IDAHO POWER
An IDACORP Company

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IDAHO PUBLIC UTILITIES COMMISSION

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 19, 2016

Ms. Jean D. Jewell
Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, ID 83720-0074

Re: Idaho Power Company's 2015 Annual FERC Form 1 Report

Dear Ms. Jewell:

Per Idaho Code 61-405, Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report and Idaho supplement for the year ending December 31, 2015. Also included is the IDACORP 2015 Annual Report. These reports will also be provided electronically.

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 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2015/Q4

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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 2015/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)* 04/15/2016

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)* 04/15/2016

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	04/15/2016	End of 2015/Q4

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	N/A
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

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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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

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	04/15/2016	End of 2015/Q4

GENERAL INFORMATION

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

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

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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 beneficiearies 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

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	04/15/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	675,000
3			
4	Executive Vice President & Chief Operating Officer	Dan Minor	460,000
5			
6	Senior Vice President & General Counsel	Rex Blackburn	350,000
7			
8	Senior Vice President, CFO & Treasurer	Steven Keen	345,000
9			
10	Senior Vice President, Power Supply	Lisa Grow	320,000
11			
12	Vice President, Public Affairs	Jeffrey Malmen	260,000
13			
14	Senior Vice President, Customer Operations	Vern Porter	260,000
15			
16	Vice President, Human Resources, Admin Services, & CIO	Lonnie Krawl	250,000
17			
18	Vice President, & Chief Risk Officer	Lori Smith	242,000
19			
20	Vice President, Corporate Controller & CAO	Ken Petersen	235,000
21			
22	Vice President of Regulatory Affairs	Gregory Said	217,000
23			
24	Corporate Secretary	Patrick Harrington	188,000
25			
26	Senior Vice President, Customer Operations	Warren Kline (1)	159,750
27			
28	Vice President, Human Resources & Corporate Services	Luci McDonald (2)	127,307
29			
30	(1) Retirement effective 6/30/15. Base shows YTD wages		
31	(2) Retirement effective 5/31/15. Base shows YTD wages		
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Jan B. Packwood (1)	900 W. Bogus View Drive, Eagle, Idaho 83616
10		
11	Darrel T. Anderson President & CEO, ** ***	Idaho Power Company, 1221 W. Idaho Street,
12		P.O. Box 70, Boise, Idaho 83707-0070
13		
14	J. LaMont Keen	481 North Strata Via Way, Boise Idaho 83712
15		
16		
17	Joan Smith (2)	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
18		
19	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
20		
21	Thomas Wilford (3)	1504 Warm Springs Avenue
22		Boise, Idaho 83712
23		
24	Richard Dahl ***	60 Laiki Pl.
25		Kailua, Hawaiil 96734
26		
27	Dennis L. Johnson	United Heritage Life Insurance
28		707 E. United Heritage Ct., Ste 130, Meridian, Idaho 83642
29		
30	Ronald W. Jibson	Questar Corporation
31		333 South State Street, Salt Lake City, Utah 84145-0433
32		
33	Richard J. Navarro (4)	1256 E. Candleridge Ct., Boise, Idaho 83712
34		
35	(1) Retired on May 21, 2015	
36	(2) Retired on May 21, 2015	
37	(3) Retired on May 21, 2015	
38	(4) Appointed to Board February 10, 2015	
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	201508285322	08/28/2015	ER09-1641-000	Idaho Power Company	FERC Electirc Tariff
2				2015 Annual	
3				Informational Filling	
4				under ER-09-1641-000	
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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 an estimated year-end 2014 net book value of approximately $43 million, subject to true-up 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 will be submitted to FERC on or before April 30, 2016.

4. None

5. None

6. Disclosed in Financial Statement footnotes, see pages 123.13 to 123.14

7. None

8. Effective 01/03/2015 a 3.0% general wage adjustment was implemented

9. Disclosed in Financial Statement footnotes, see pages 123.18 to 123.19

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 in 2015. Her husband, Matt Smith, was also an employee of Idaho Power in 2015.

11. None

12. None

13. Director Changes in 2015:
- Richard J. Navarro appointed to Board 2/11/2015
- Jan B. Packwood, Joan H. Smith, and Thomas J. Wilford retired from the Board 5/21/2015

Officer Changes in 2015:
- Warren Kline retired as Sr. Vice President- Customer Operations effective

6/30/2015
- Luci K. McDonald retired as Vice President- Human Resources and Corporate Services effective 5/31/2015
- N. Vern Porter title changed from "Vice President" to "Sr. Vice President of Customer Operations" effective 4/1/2015
- Lonnie G. Krawl title changed from "Vice President and Chief Information Officer" to "Vice President of Human Resources, Administrative Services and Chief Information Officer" effective 4/1/2015

Officer changes approved in 2015 but not effective until 2016:
- Daniel B. Minor title change from "Executive Vice President and Chief Operating Officer" to "Executive Vice President"
- Lisa A. Grow title change from "Sr. Vice President- Power Supply to "Sr. Vice President of Operations"
- N. Vern Porter title change from "Sr. Vice President of Customer Operations" to "Vice President of Customer Operations"
- Lonnie G. Krawl title change from "Vice President and Chief Information Officer" to "Sr. Vice President of Administrative Services and Chief Information Officer"
- Tessia R. Park new appointment to "Vice President of Power Supply"
- Jeffrey S. Glenn new appointment to "Vice President of Information Technology"

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	04/15/2016	End of 2015/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	5,492,554,138	5,255,302,762
3	Construction Work in Progress (107)	200-201	396,931,372	401,929,509
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,889,485,510	5,657,232,271
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,097,432,010	2,021,073,827
6	Net Utility Plant (Enter Total of line 4 less 5)		3,792,053,500	3,636,158,444
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)		3,792,053,500	3,636,158,444
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,555,480	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	84,137,401	83,477,460
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)		416	647
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,560,677	45,082,335
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		126,480	63,323
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		110,380,454	130,179,245
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		100,745,383	46,581,578
36	Special Deposits (132-134)		1,637,072	1,079,260
37	Working Fund (135)		10,600	13,600
38	Temporary Cash Investments (136)		10,000,000	100,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		75,650,719	85,040,915
41	Other Accounts Receivable (143)		23,486,155	14,677,441
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,355,042	4,650,829
43	Notes Receivable from Associated Companies (145)		1,156,202	2,053,197
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	61,818,257	55,170,482
46	Fuel Stock Expenses Undistributed (152)	227	0	599
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	52,445,228	50,305,479
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

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	04/15/2016	End of 2015/Q4

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	4,478,320	5,098,760
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)		17,845,551	18,355,589
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		65,804,608	56,269,642
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		405,239	634,183
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		126,480	63,323
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)		414,001,812	330,666,573
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,539,636	15,815,910
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	1,355,572,128	1,237,823,724
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,177	873,939
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)		1,650,910	1,053,324
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	66,701,295	45,564,713
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)		29,731,072	12,799,888
82	Accumulated Deferred Income Taxes (190)	234	270,188,395	289,103,584
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,740,384,613	1,603,035,082
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,056,820,379	5,700,039,344

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	04/15/2016	end of 2015/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	1,045,751,377	952,335,875
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	81,674,308	81,014,366
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)	-21,275,735	-24,157,999
16	Total Proprietary Capital (lines 2 through 15)		1,914,187,490	1,817,229,782
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,725,460,000	1,595,460,000
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	22,012,273	23,075,909
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,458,587	3,034,022
24	Total Long-Term Debt (lines 18 through 23)		1,743,013,686	1,615,501,887
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)		1,873,877	1,994,972
29	Accumulated Provision for Pensions and Benefits (228.3)		394,131,877	403,474,921
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	3,865,254
31	Accumulated Provision for Rate Refunds (229)		87,689,554	72,974,757
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)		26,152,620	21,930,049
35	Total Other Noncurrent Liabilities (lines 26 through 34)		509,847,928	504,239,953
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		119,524,930	113,979,552
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,058,872	2,027,220
41	Customer Deposits (235)		4,731,724	1,568,822
42	Taxes Accrued (236)	262-263	5,192,418	-10,635,253
43	Interest Accrued (237)		22,387,590	22,670,165
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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	04/15/2016	end of 2015/Q4

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)		1,921,386	2,599,099
48	Miscellaneous Current and Accrued Liabilities (242)		53,364,600	40,889,480
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		4,972,600	3,960,704
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)		213,154,120	177,059,789
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		4,678,929	3,303,553
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,654,930	79,162,831
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	11,757,998	11,635,642
60	Other Regulatory Liabilities (254)	278	67,711,655	64,843,269
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)		1,349,907,020	1,248,630,361
64	Accum. Deferred Income Taxes-Other (283)		162,906,623	178,432,277
65	Total Deferred Credits (lines 56 through 64)		1,676,617,155	1,586,007,933
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,056,820,379	5,700,039,344

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	04/15/2016	End of 2015/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	1,266,201,447	1,277,640,977		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	731,125,349	780,281,536		
5	Maintenance Expenses (402)	320-323	69,399,154	68,283,304		
6	Depreciation Expense (403)	336-337	130,382,128	125,245,540		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	549,017	495,029		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,095,926	7,172,382		
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)		82,611	73,650		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	32,808,301	31,748,230		
15	Income Taxes - Federal (409.1)	262-263	12,593,365	-7,413,733		
16	- Other (409.1)	262-263	5,986,110	6,908,583		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	86,269,807	152,963,217		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	58,085,989	134,837,097		
19	Investment Tax Credit Adj. - Net (411.4)	266	492,099	41,541		
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)		97,422	186,382		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		232,049	309,716		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,018,832,505	1,031,085,516		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		247,368,942	246,555,461		

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	04/15/2016	End of 2015/Q4

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
1,266,201,447	1,277,640,977					2
						3
731,125,349	780,281,536					4
69,399,154	68,283,304					5
130,382,128	125,245,540					6
549,017	495,029					7
7,095,926	7,172,382					8
						9
						10
						11
82,611	73,650					12
						13
32,808,301	31,748,230					14
12,593,365	-7,413,733					15
5,986,110	6,908,583					16
86,269,807	152,963,217					17
58,085,989	134,837,097					18
492,099	41,541					19
						20
						21
97,422	186,382					22
						23
232,049	309,716					24
1,018,832,505	1,031,085,516					25
247,368,942	246,555,461					26

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	04/15/2016	End of 2015/Q4

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)		247,368,942	246,555,461		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,304,085	1,009,910		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,485,862	1,136,669		
33	Revenues From Nonutility Operations (417)		33,733	37,547		
34	(Less) Expenses of Nonutility Operations (417.1)		10,586	22,828		
35	Nonoperating Rental Income (418)		-791	-527		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,659,942	7,092,887		
37	Interest and Dividend Income (419)		3,039,556	2,704,620		
38	Allowance for Other Funds Used During Construction (419.1)		21,785,246	17,930,898		
39	Miscellaneous Nonoperating Income (421)		2,365,842	2,453,947		
40	Gain on Disposition of Property (421.1)		-20	-4,240		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,691,145	30,065,545		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,156		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		750,960	747,094		
46	Life Insurance (426.2)		-1,738,804	-1,164,064		
47	Penalties (426.3)		48,305	27,106		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,477,633	1,561,921		
49	Other Deductions (426.5)		9,937,000	8,332,431		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,475,094	9,506,644		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	21,055	24,797		
53	Income Taxes-Federal (409.2)	262-263	353,061	-914,126		
54	Income Taxes-Other (409.2)	262-263	69,362	-41,215		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	5,911,613	1,085,673		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	8,478,300	2,008,392		
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)		-2,123,209	-1,853,263		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		25,339,260	22,412,164		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		83,055,805	80,561,920		
63	Amort. of Debt Disc. and Expense (428)		1,556,825	1,610,773		
64	Amortization of Loss on Reaquired Debt (428.1)		1,521,812	1,060,585		
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)		6,859	10,524		
68	Other Interest Expense (431)		5,627,193	4,800,939		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,043,775	8,464,109		
70	Net Interest Charges (Total of lines 62 thru 69)		81,724,719	79,580,632		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		190,983,483	189,386,993		
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)		190,983,483	189,386,993		

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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	04/15/2016	End of 2015/Q4

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		939,062,769	836,965,502
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)		184,323,541	182,294,106
17	Appropriations of Retained Earnings (Acct. 436)			
18				(6,613,580)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			(6,613,580)
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			-96,908,039	(88,583,259)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-96,908,039	(88,583,259)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		6,000,000	15,000,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,032,478,271	939,062,769
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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	04/15/2016	End of 2015/Q4

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)
39				
40				
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)		1,045,751,377	952,335,875
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		81,014,366	88,921,479
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,659,942	7,092,887
51	(Less) Dividends Received (Debit)		6,000,000	15,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		81,674,308	81,014,366

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	04/15/2016	End of 2015/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)	190,983,483	189,386,993
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	130,382,128	125,245,540
5	Amortization of (detail in footnote):	11,590,185	11,250,901
6			
7			
8	Deferred Income Taxes (Net)	25,793,350	17,218,276
9	Investment Tax Credit Adjustment (Net)	315,879	26,665
10	Net (Increase) Decrease in Receivables	3,988,719	22,570,540
11	Net (Increase) Decrease in Inventory	-8,079,325	-15,385,702
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	17,501,301	-18,687,818
14	Net (Increase) Decrease in Other Regulatory Assets	1,465,215	16,794,041
15	Net Increase (Decrease) in Other Regulatory Liabilities	12,233,990	15,341,861
16	(Less) Allowance for Other Funds Used During Construction	21,785,246	17,930,898
17	(Less) Undistributed Earnings from Subsidiary Companies	659,942	-7,907,113
18	Other (provide details in footnote):	-18,199,440	4,789,855
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	345,530,297	358,527,367
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-315,753,782	-291,841,495
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	-21,785,246	-17,930,898
31	Other (provide details in footnote):	13,456,680	3,551,443
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-280,511,856	-270,359,154
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	896,996	-15,317,379
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-44,105,638	-8,000,000
45	Proceeds from Sales of Investment Securities (a)	34,243,180	

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		50,208
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):	-1,374,426	4,906,085
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-290,851,744	-288,720,240
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	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)	250,000,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-121,063,637	-1,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-22,646,072	
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-96,908,039	-88,583,259
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	9,382,252	-89,646,895
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	64,060,805	-19,839,768
87			
88	Cash and Cash Equivalents at Beginning of Period	46,695,178	66,534,946
89			
90	Cash and Cash Equivalents at End of period	110,755,983	46,695,178

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

Amortization	
Plant	7,095,926
Unamortized debt expense	3,090,337
Unamortized discount	290,435
Water rights	1,042,009
Other	71,478
	11,590,185

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

Cash paid during the period for:	
Income taxes	3,547,630
Interest (net of amount capitalized)	79,225,751

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

Cash Flow from Operating Activities (Other)	
Pension and postretirement benefit plan expense	30,185,123
Contributions to pension and postretirement benefit plans	(42,821,074)
Unbilled revenues	(7,691,484)
Prepayments	922,055
Company owned life insurance	5,327,068
Deposits from third parties	5,309,053
Other	(9,430,181)
	(18,199,440)

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	23,839,605

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

Other Cash Flows from Plant	
Sale of utility property	71,180
Payments received from joint funding partners	11,377,277
Sale of emission allowances and renewable energy certificates	2,008,223
	13,456,680

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

Other Investing Cash Flows	
EDC plan investments	32,308
Feasibility study costs	(1,406,964)
Miscellaneous other investing activities	230
	(1,374,426)

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

Other Financing Cash Flows	
Make-whole premium on retirement of long-term debt	(17,871,600)
Debt issuance costs	(3,059,472)
Discount on debt issuance	(1,715,000)
	(22,646,072)

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	04/15/2016	End of 2015/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(16,553,375)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,728,379
3	Preceding Quarter/Year to Date Changes in Fair Value				(9,333,003)
4	Total (lines 2 and 3)				(7,604,624)
5	Balance of Account 219 at End of Preceding Quarter/Year				(24,157,999)
6	Balance of Account 219 at Beginning of Current Year				(24,157,999)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,667,521
8	Current Quarter/Year to Date Changes in Fair Value				214,743
9	Total (lines 7 and 8)				2,882,264
10	Balance of Account 219 at End of Current Quarter/Year				(21,275,735)

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	04/15/2016	End of 2015/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(16,553,375)		
2			1,728,379		
3			(9,333,003)		
4			(7,604,624)	189,386,993	181,782,369
5			(24,157,999)		
6			(24,157,999)		
7			2,667,521		
8			214,743		
9			2,882,264	190,983,483	193,865,747
10			(21,275,735)		

NOTES TO FINANCIAL STATEMENTS

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

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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 with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. 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. As a result, 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, primarily notes receivable from business transactions, 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, 2015 and 2014. 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 rider 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 2.68 percent in 2015 and 2014.

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 2015 or 2014.

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 2015 and 7.7 percent for 2014.

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.

Recently Issued Accounting Pronouncements

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 amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2017, including interim periods, with early adoption permitted one year earlier. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. Idaho Power is currently evaluating the impact of ASU 2014-09 on its financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (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, and are effective for interim and annual reporting periods beginning after December 31, 2015. Idaho Power does not believe the impact of ASU 2015-02 on its financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. Idaho Power is currently evaluating the impact of ASU 2016-01 on its financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2015 up to February 18, 2016, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2016. 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:

	2015	2014
Federal income tax expense at 35% statutory rate	$ 82,633	$ 71,810
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,331)	(2,483)
AFUDC	(11,140)	(9,238)
Capitalized interest	2,693	2,278
Investment tax credits	(2,963)	(3,002)
Removal costs	(4,807)	(3,656)
Capitalized overhead costs	(8,750)	(8,750)
Capitalized repair costs	(28,700)	(26,250)
Bond redemption costs	(6,459)	—
Tax method change – capitalized repairs	—	(24,516)
State income taxes, net of federal benefit	7,503	5,334
Depreciation	17,149	16,040
Other, net	283	(1,783)
Total income tax expense	$ 45,111	$ 15,784
Effective tax rate	19.10%	7.70%

The items comprising income tax expense are as follows:

	2015	2014
	(thousands of dollars)	
Income taxes current:		
Federal	$ 12,946	$ (8,328)
State	6,056	6,867
Total	19,002	(1,461)
Income taxes deferred:		
Federal	28,103	23,624
State	(2,486)	(6,421)
Total	25,617	17,203
Investment tax credits:		
Deferred	3,455	3,044
Restored	(2,963)	(3,002)
Total	492	42
Total income tax expense	$ 45,111	$ 15,784

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

	2015	2014
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 51,131	$ 55,490
Deferred compensation	27,489	25,240
Deferred revenue	34,282	28,529
Tax credits	30,223	26,768
Retirement benefits	126,885	132,571
Other	10,745	14,553
Total	280,755	283,151
Deferred tax liabilities:		
Property, plant and equipment	474,879	451,118
Regulatory assets	875,028	802,188
Power cost adjustments	18,489	23,192
Retirement benefits	126,090	122,360
Other	28,895	22,252
Total	1,523,381	1,421,110
Net deferred tax liabilities	$ 1,242,626	$ 1,137,959

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 they have no material income tax uncertainties for 2015 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 their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2015 for federal and 2012-2015 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 2015, the IRS completed its examination of IDACORP's 2014 tax year with no unresolved income tax issues.

Tax Accounting Method Changes for Repair-Related Expenditures

In the fourth quarter of 2014, Idaho Power finalized an income tax accounting method change for its 2014 tax year associated with the electric generation property portion of its capitalized repairs tax method it adopted in fiscal year 2010. As a result of the change, Idaho Power recorded an $8.8 million tax benefit related to the cumulative method change adjustment for years prior to 2014 and reversed a related $4.6 million tax expense estimate it had recorded in 2013 (discussed below), for a total adjustment of $13.4 million.

The method change was pursuant to Revenue Procedure 2013-24 and brought Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric generation property. The change also incorporated provisions of the final tangible property regulations issued by the U.S. Treasury Department and IRS in 2013 that addressed the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP's 2014 consolidated federal income tax return in September 2015. The IRS approved the method change prior to the filing of the return as part of IDACORP's 2014 CAP examination.

In 2014 Idaho Power, in coordination with the IRS through IDACORP's CAP examination process, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in the third quarter of 2014. Idaho Power finalized these changes with the filing of IDACORP's 2013 consolidated federal income tax return in September 2014. The IRS approved the repairs method modifications prior to the filing of the return as part of IDACORP's 2013 CAP examination.

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 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):

Description	Remaining Amortization Period	As of December 31, 2015 Earning a Return(1)	Not Earning a Return	Total as of December 31, 2015	2014
Regulatory Assets:					
Income taxes		$	$ 875,027	$ 875,027	$ 802,188
Unfunded postretirement benefits(2)		—	251,762	251,762	264,548
Pension expense deferrals		62,642	23,148	85,790	63,644
Energy efficiency program costs(3)		4,482	—	4,482	4,690
Power supply costs(4)	Varies	47,220	—	47,220	59,189
Fixed cost adjustment(4)	2016-2017	36,820	—	36,820	23,737
Asset retirement obligations(5)		—	14,410	14,410	17,309
Mark-to-market liabilities(6)		—	4,973	4,973	3,961
Long-term service agreement(7)	2043	18,592	11,633	30,225	—
Other	2016-2021	1,096	3,704	4,800	3,121
Total		$ 170,852	$ 1,183,573	$ 1,355,509	$ 1,242,387
Regulatory Liabilities:					
Income taxes		$	$ 51,131	$ 51,131	$ 55,490
Energy efficiency program costs(3)		6,554	—	6,554	—
Power supply costs(4)		—	—	—	1
Settlement agreement sharing mechanism(4)	2016-2017	3,159	—	3,159	7,999
Mark-to-market assets(6)		—	405	405	1,880
Other		5,219	1,180	6,399	4,036
Total		$ 14,932	$ 52,716	$ 67,648	$ 69,406

(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 10.

(3) The 2015 energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance. Both jurisdictions' balances were assets at December 31, 2014.

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

(5) Asset retirement obligations are discussed in Note 12.

(6) Mark-to-market assets and liabilities are discussed in Note 15.

(7) A portion not earning a return as of December 31, 2015 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 (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA 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. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs 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.

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 Idaho 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 Idaho 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, 2015	$ (11.6)	The net decrease in Idaho 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.
June 1, 2014	$ (88.2)	2014 PCA rates are net of (a) $20.0 million of surplus Idaho energy efficiency rider funds, and (b) $7.6 million of customer revenue sharing under a regulatory settlement stipulation. In addition, on June 1, 2014, there was an increase in base net power supply costs that shifted $99.3 million in power supply expenses from recovery via the PCA mechanism to recovery via base rates. The shifting of base net power supply costs is discussed in more detail below.

In March 2014, the IPUC issued an order approving Idaho Power's application requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

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 (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2015, and 2014, are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
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.
2014 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.

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 Idaho PCA rate that became effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: In December 2011, the IPUC issued an order, separate from the 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 may 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.

As Idaho Power's Idaho ROE exceeded 10.5 percent for each of 2012, 2013, and 2014, Idaho Power did not amortize additional ADITC for those years, but instead shared a portion of its Idaho-jurisdiction earnings with Idaho customers. The amounts Idaho

Power recorded in 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation was $8 million as refunds to customers and $16.7 million as pre-tax charges to pension expenses.

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 power cost adjustment 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 power cost adjustment, 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.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015 under the October 2014 Idaho settlement stipulation, as its Idaho ROE for 2015 was above 10.0 percent.

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)
2014	June 1, 2015-May 31, 2016	$16.9
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

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.

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 three most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate	(per kW-year)
October 1, 2015 to September 30, 2016	$	23.43
October 1, 2014 to September 30, 2015	$	22.48
October 1, 2013 to September 30, 2014	$	22.80

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $121.3 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):

	2015	2014
First mortgage bonds:		
6.025% Series due 2018	$ —	$ 120,000
6.15% Series due 2019	100,000	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% 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	—
Total first mortgage bonds	1,555,000	1,425,000
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	2,127	3,191
Unamortized discounts	(4,459)	(3,034)
Total Idaho Power outstanding debt(2)	$ 1,743,013	$ 1,615,502

(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, 2015 to $1.721 billion.
(2) At December 31, 2015 and 2014, the overall effective cost of Idaho Power's outstanding debt was 4.96 percent and 5.19 percent, respectively.

At December 31, 2015, the maturities for the aggregate amount of Idaho Power's long-term debt outstanding were as follows (in thousands of dollars):

2016	2017	2018	2019	2020	Thereafter
$ 1,064	$ 1,064	$ —	$ 100,000	$ 230,000	$ 1,415,344

Long-Term Debt Issuances, Maturities, and Availability

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, 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 2013, 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. 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. 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 maximum interest rate limit of seven percent.

On May 22, 2013, IDACORP and Idaho Power filed a joint shelf registration statement with the 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 July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight 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 J (Series J Notes), under Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes pursuant to the Indenture. As of December 31, 2015, $250 million in principal amount of Series J Notes remained available for issuance under the Indenture.

In March 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 March 10, 2016, Idaho Power issued a notice of redemption to redeem, prior to maturity, its $100 million in principal amount of 6.15% first mortgage bonds, medium-term notes, Series H due April 2019, with the redemption effective April 11, 2016. 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 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.

Mortgage: As of December 31, 2015, Idaho Power could issue under its Indenture approximately $1.5 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 chooses 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.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Indenture for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 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 Credit Agreements replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide credit facilities 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 Idaho Power credit facility has similar terms and conditions. The interest rates for any borrowings under the facilities are 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, as applicable; 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 their respective credit facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities. The credit facilities mature on November 6, 2020, though Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

At December 31, 2015 and December 31, 2014 no loans or commercial paper were outstanding under Idaho Power's facility. At December 31, 2015, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding.

6. COMMON STOCK

No contributions were made to Idaho Power in 2015 or 2014, 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 their respective credit facilities 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, 2015, the leverage ratio for Idaho Power was 48 percent. Based on these restrictions, Idaho Power's dividends were limited to $980 million, at December 31, 2015. 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, 2015, 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, 2015, Idaho Power's common equity capital was 52 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 prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the Federal Power Act 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). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP (for officers and key employees) permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2015, the maximum number of shares available under the LTICP and RSP were 1,043,542 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. 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 portion of IDACORP common stock:

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2015	250,396	$ 43.91
Shares granted	115,863	54.05
Shares forfeited	(10,413)	55.63
Shares vested	(127,056)	36.84
Nonvested shares at December 31, 2015	228,790	$ 52.44

The total fair value of shares vested during the years ended December 31, 2015 and 2014 was $8.3 million and $6.6 million, respectively. At December 31, 2015, Idaho Power had $4.7 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 1.68 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2015, a total of 15,324 of IDACORP common stock shares were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $62.62 per share. Directors elected to defer receipt of 3,831 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 the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to Idaho Power for those costs associated with Idaho Power's employees (in thousands of dollars):

	2015	2014
Compensation cost	$ 5,221	$ 5,458
Income tax benefit	2,042	2,134

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2015, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2016	2017	2018	2019	2020	Thereafter
Cogeneration and power production	$ 199,156	$ 233,197	$ 241,356	$ 234,772	$ 234,316	$ 3,592,891
Fuel	60,122	43,276	16,206	9,169	8,833	114,417

As of December 31, 2015, Idaho Power had 784 MW nameplate capacity of PURPA-related projects on-line, with an additional 448 MW nameplate capacity of projects projected to be on-line by June 1, 2017. Of the 448 MW nameplate capacity of projected PURPA-related projects at the end of 2015, as of February 5, 2016, three contracts with solar projects with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts. 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 $131 million in 2015 and $145 million in 2014.

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

	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 233	$ 971	$ 985	$ 1,062	$ 897	$ 12,625
Equipment, maintenance, and service agreements	48,707	11,703	14,869	9,214	12,095	83,721
FERC and other industry-related fees	12,894	12,746	12,746	8,632	5,942	29,708

Idaho Power's expense for operating leases was approximately $4.4 million in 2015 and $5.9 million in 2014.

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 $73 million at December 31, 2015, 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, 2015, the value of the reclamation trust fund was $70 million. During 2015, 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 add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. 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, 2015, 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 in this Note 9. 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 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 the financial statements as a whole; however, future accruals could be material in a given period. Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. For matters that affect Idaho Power's operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

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. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit, and thus there remains some uncertainty about the ultimate outcome of the proceedings. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that the current state of the FERC's orders, if maintained, and the settlement releases they have obtained, will restrict potential claims that might result from the pending proceedings. As a result, Idaho Power predicts that these matters will not have a material adverse effect on the results of operations or financial condition. However, if unanticipated orders are issued by the FERC or by the Ninth Circuit Court of Appeals or other courts, exposure to indirect claims in the proceedings could exist. These indirect claims would consist of so-called "ripple claims," which involve potential claims for refunds in the Pacific Northwest markets from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. Given the speculative nature of ripple claims and in light of Idaho Power's and IESCo participating in the market as both a buyer and seller of energy, Idaho Power and IESCo are unable to estimate the possible loss or range of loss that could result from the proceedings and have no amount accrued relating to the proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

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 includes alternative causes of action for constructive fraudulent transfer under the federal bankruptcy code, Idaho law, and federal law, with requests for recovery from Idaho Power in amounts up to approximately $36 million. The complaint alleges that the payments made by Hoku Corporation to Idaho Power are 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.

As of the date of this report, the proceedings are in preliminary stages and it is not possible to determine Idaho Power's potential liability, if any, or to reasonably estimate a possible loss or range of possible loss, if any, within the trustee's alternative prayers for relief. Idaho Power intends to vigorously defend against the claims.

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 the 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 generating 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 a nonqualified defined benefit pension plan for certain senior management employees called the Security Plan for Senior Management Employees (SMSP). Idaho Power also has a nonqualified defined benefit pension plan for directors that were 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 2015, and 2014 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	
	2015	2014	2015	2014
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 844,812	$ 695,093	$ 94,410	$ 77,773
Service cost	33,164	25,292	1,689	1,645
Interest cost	35,171	35,415	3,868	3,856
Actuarial (gain) loss	(47,952)	114,496	(352)	15,324
Benefits paid	(29,672)	(25,484)	(4,226)	(4,188)
Projected benefit obligation at December 31	835,523	844,812	95,389	94,410
Change in plan assets:				
Fair value at January 1	559,719	545,092	—	—
Actual return on plan assets	(9,431)	10,111	—	—
Employer contributions	39,000	30,000	—	—
Benefits paid	(29,672)	(25,484)	—	—
Fair value at December 31	559,616	559,719	—	—
Funded status at end of year	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,423)	$ (4,193)
Noncurrent liabilities	(275,907)	(285,093)	(90,966)	(90,217)
Net amount recognized	(275,907)	(285,093)	(95,389)	(94,410)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	253,212	263,350	34,260	38,808
Prior service cost	74	295	673	857
Subtotal	253,286	263,645	34,933	39,665
Less amount recorded as regulatory asset	(253,286)	(263,645)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,933	$ 39,665
Accumulated benefit obligation	$ 714,994	$ 719,617	$ 86,838	$ 84,684

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 $69.3 million and $65.0 million at December 31, 2015 and 2014, 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	
	2015	2014	2015	2014
Service cost	$ 33,164	$ 25,292	$ 1,689	$ 1,645
Interest cost	35,171	35,415	3,868	3,856
Expected return on assets	(42,310)	(42,289)	—	—
Amortization of net loss	13,927	3,911	4,195	2,618
Amortization of prior service cost	221	347	185	220
Net periodic pension cost	40,173	22,676	9,937	8,339
Adjustments due to the effects of regulation(1)	(21,173)	12,124	—	—
Net periodic benefit cost recognized for financial reporting	$ 19,000	$ 34,800	$ 9,937	$ 8,339

(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	
	2015	2014	2015	2014
Actuarial (loss) gain during the year	$ (3,790)	$ (146,674)	$ 353	$ (15,324)
Reclassification adjustments for:				
Amortization of net loss	13,927	3,911	4,195	2,618
Amortization of prior service cost	221	347	185	220
Adjustment for deferred tax effects	(4,050)	55,678	(1,851)	4,881
Adjustment due to the effects of regulation	(6,308)	86,738	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ 2,882	$ (7,605)

In 2016, Idaho Power expects to recognize as components of net periodic benefit cost $17.3 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2015, relating to the pension plan and SMSP. This amount consists of $13.5 million of amortization of net loss and $0.1 million of amortization of prior service cost for the pension plan, and $3.5 million of amortization of net loss and $0.2 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):

	2016	2017	2018	2019	2020	2021-2025
Pension Plan	$ 30,086	$ 32,529	$ 35,156	$ 37,795	$ 40,527	$ 241,079
SMSP	4,516	4,582	4,371	4,547	4,964	25,659

As of December 31, 2015, Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2016, though Idaho Power plans to contribute at least $20 million to the pension plan during 2016 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):

	2015	2014
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 65,999	$ 57,341
Service cost	1,235	1,011
Interest cost	2,678	2,841
Actuarial (gain) loss	(5,008)	7,026
Benefits paid(1)	(2,511)	(2,220)
Benefit obligation at December 31	62,393	65,999
Change in plan assets:		
Fair value of plan assets at January 1	38,375	37,111
Actual return on plan assets	85	3,888
Employer contributions(1)	(383)	(404)
Benefits paid(1)	(2,511)	(2,220)
Fair value of plan assets at December 31	35,566	38,375
Funded status at end of year (included in noncurrent liabilities)	$ (26,827)	$ (27,624)

(1) Contributions and benefits paid are each net of $3,518 thousand and $3,379 thousand of plan participant contributions, and $330 thousand and $344 thousand of Medicare Part D subsidy receipts for 2015 and 2014, respectively.

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

	2015	2014
Net (gain) loss	$ (1,654)	$ 759
Prior service cost	130	145
Subtotal	(1,524)	904
Less amount recognized in regulatory assets	1,524	(904)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2015	2014
Service cost	$ 1,235	$ 1,011
Interest cost	2,678	2,841
Expected return on plan assets	(2,680)	(2,595)
Amortization of prior service cost	15	183
Net periodic postretirement benefit cost	$ 1,248	$ 1,440

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

	2015	2014
Actuarial gain (loss) during the year	$ 2,413	$ (5,733)
Reclassification adjustments for:		
Amortization of prior service cost	15	183
Adjustment for deferred tax effects	(949)	2,170
Adjustment due to the effects of regulation	(1,479)	3,380
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2016, Idaho Power expects to recognize as components of net periodic benefit cost $26 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2015, relating to the postretirement benefit plan. The entire amount represents $26 thousand of amortization of prior service cost.

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):

	2016	2017	2018	2019	2020	2021-2025
Expected benefit payments	$4,010	$4,050	$4,100	$4,150	$4,190	$21,030
Expected Medicare Part D subsidy receipts	380	430	470	510	560	3,480

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	
	2015	2014	2015	2014	2015	2014
Discount rate	4.6%	4.25%	4.6%	4.2%	4.6%	4.2%
Rate of compensation increase[1]	4.11%	4.3%	4.5%	4.5%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5%	5%
Measurement date	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014

(1) The 2015 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	
	2015	2014	2015	2014	2015	2014
Discount rate	4.25%	5.2%	4.2%	5.1%	4.2%	5.15%
Expected long-term rate of return on assets	7.5%	7.75%	—	—	7.25%	7.25%
Rate of compensation increase	4.11%	4.3%	4.5%	4.5%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5%	5%

In October 2014, the Society of Actuaries released a new set of mortality tables referred to as RP-2014. Mortality tables are used by defined benefit plans to estimate the life expectancy of plan participants and the expected length of benefit payments in retirement. Idaho Power's measurement of its plan benefit obligations as of December 31, 2015 and 2014, and its net periodic benefit cost for 2015, reflect the adoption of the new tables, which was not material.

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 9.7 percent in 2015 and is assumed to decrease to 8.3 percent in 2016, 6.8 percent in 2017, and 5.4 percent in 2018 and to gradually decrease to 4.8 percent by 2099. 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, 2015 (in thousands of dollars):

	One-Percentage-Point Increase	Decrease
Effect on total of cost components	$ 407	$ (297)
Effect on accumulated postretirement benefit obligation	3,719	(2,838)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2015 for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2015
Debt securities	24%	25%
Equity securities	54%	55%
Real estate	6%	7%
Other plan assets	16%	13%
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 15. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2015				
Pension plan assets:				
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	59,787	—	67,485
Equity Securities: Emerging Markets	9,679	23,167	—	32,846
Real estate	—	—	39,035	39,035
Private market investments	—	—	37,316	37,316
Commodities funds	—	27,555	—	27,555
Total pension assets	$ 258,267	$ 224,998	$ 76,351	$ 559,616
Postretirement plan assets(1)	$ 16	$ 35,550	$ —	$ 35,566
Assets at December 31, 2014				
Pension plan assets:				
Cash and cash equivalents	$ 19,190	$ —	$ —	$ 19,190
Short-term bonds	—	10,991	—	10,991
Intermediate bonds	—	101,867	—	101,867
Long-term bonds	—	21,615	—	21,615
Equity Securities: Large-Cap	66,151	—	—	66,151
Equity Securities: Mid-Cap	68,974	—	—	68,974
Equity Securities: Small-Cap	50,972	—	—	50,972
Equity Securities: Micro-Cap	22,962	—	—	22,962
Equity Securities: International	6,555	57,705	—	64,260
Equity Securities: Emerging Markets	8,629	22,915	—	31,544
Real estate	—	—	33,996	33,996
Private market investments	—	—	37,118	37,118
Commodities funds	—	30,079	—	30,079
Total pension assets	$ 243,433	$ 245,172	$ 71,114	$ 559,719
Postretirement plan assets(1)	$ 11	$ 38,364	$ —	$ 38,375

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

For the year ended December 31, 2015, there were no significant transfers into or out of Levels 1, 2, or 3. For the year ended December 31, 2014, there were $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1.

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3) (in thousands of dollars):

	Private Equity	**Real Estate**	**Total**
Beginning balance - January 1, 2014	$ 33,709	$ 28,019	$ 61,728
Realized gains	1,430	866	2,296
Unrealized (losses) gains	(545)	1,305	760
Purchases	2,434	3,806	6,240
Settlements	90	—	90
Ending balance - December 31, 2014	37,118	33,996	71,114
Realized gains	1,897	923	2,820
Unrealized (losses) gains	(3,152)	3,193	41
Purchases	2,255	923	3,178
Sales	(802)	—	(802)
Ending balance - December 31, 2015	$ 37,316	$ 39,035	$ 76,351

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs:

Level 2 Bonds, Equity Securities, and Level 2 Commodities: These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 2 Postretirement Assets: These assets represent an investment in a life insurance contract and are 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.

Level 3 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 company, 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.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. 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. Venture capital fund investments are valued by the fund company 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.

The fair value of the Level 3 assets is determined based on pricing provided or reviewed by third-party vendors to our investment managers. While the input amounts used by the pricing vendors in determining fair value are not provided, and therefore unavailable for Idaho Power's review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar assets classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately $7 million each year from 2014 to 2015.

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, 2015 and 2014 were $2.0 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 2015 and 2014 (in thousands of dollars):

	2015		2014	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 2,422,175	2.46%	$ 2,316,941	2.48%
Transmission	1,077,065	2.01%	1,016,207	2.03%
Distribution	1,578,445	2.72%	1,516,933	2.72%
General and Other	407,779	5.62%	398,131	5.49%
Total in service	5,485,464	2.68%	5,248,212	2.68%
Accumulated provision for depreciation	(2,097,432)		(2,021,074)	
In service - net	$ 3,388,032		$ 3,227,138	

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, 2015 (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	$ 641,382	$ 46,094	$ 296,671	33	771
Boardman	Boardman, OR	81,252	113	63,715	10	64
Valmy Units 1 and 2	Winnemucca, NV	402,276	1,135	184,604	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 2015 and $79 million in 2014.

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 2015 and $9 million in 2014.

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 2015, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $5.0 million in the recorded AROs. The increase in the AROs in 2015 is primarily related to the impact of new coal combustion residual regulations on the Bridger generating facility.

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

	2015	2014
Balance at beginning of year	$ 21,930	$ 25,765
Accretion expense	993	1,061
Revisions in estimated cash flows	5,043	(4,140)
Liability settled	(1,813)	(756)
Balance at end of year	$ 26,153	$ 21,930

13. INVESTMENTS

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

	2015	2014
Idaho Power investments:		
IERCO	$ 84,137	$ 83,477
Exchange traded short-term bond funds and cash equivalents	24,459	44,942
Executive deferred compensation plan investments	102	141
Other investments	—	1
Total Idaho Power investments	108,698	128,561

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, 2015 and December 31, 2014. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2015	2014
Proceeds from sales	$ 34,243	$ —
Gross realized gains from sales	—	—
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, 2015 and December 31, 2014, 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, 2015 and 2014 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income(1)	
		2015	2014
Financial swaps	Off-system sales	$ 2,882	$ (4,119)
Financial swaps	Purchased power	748	(1,416)
Financial swaps	Fuel expense	(6,045)	3,862
Financial swaps	Other operations and maintenance	(50)	(158)
Forward contracts	Off-system sales	—	277
Forward contracts	Purchased power	(6)	(279)
Forward contracts	Fuel expense	54	94

(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, 2015 and 2014 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
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
December 31, 2014							
Current:							
Financial swaps	Other current assets	$ 2,509	$ (2,002)	$ 507	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	379	(379)	—	4,335	(379)	3,956
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	5	—	5
Long-term:							
Forward contracts	Other assets	63	—	63	—	—	—
Total		$ 3,015	$ (2,381)	$ 634	$ 5,096	$ (1,135)	$ 3,961

(1) Current asset and current liability derivative amounts offset include $0.9 million of collateral receivable and $1.2 million of collateral payable and for the periods ending December 31, 2015 and 2014, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2015 and 2014 (in thousands of units):

		December 31,	
Commodity	**Units**	**2015**	**2014**
Electricity purchases	MWh	357	115
Electricity sales	MWh	120	238
Natural gas purchases	MMBtu	11,597	6,913
Natural gas sales	MMBtu	78	409
Diesel purchases	Gallons	1,068	243

Credit Risk

At December 31, 2015, 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, 2015, was $5.7 million. Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2015, Idaho Power would have been required to post an additional $9.0 million of cash collateral to its counterparties.

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, 2015 and 2014.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014 (in thousands of dollars):

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
-Money market funds	10,000	—	—	10,000	100	—	—	100
Derivatives	340	64	—	404	506	128	—	634
Trading securities: Equity securities	102	—	—	102	141	—	—	141
Available-for-sale securities: ETFs	24,459	—	—	24,459	44,942	—	—	44,942
Liabilities:								
Derivatives	$ 286	$ 4,686	$ —	$ 4,972	$ 17	$ 3,944	$ —	$ 3,961

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 exchange-traded short-term bond and money market funds related to the SMSP and are held in a Rabbi Trust.

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2015 and 2014, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Liabilities:				
Long-term debt(1)	$ 1,726,474	$ 1,813,243	$ 1,615,502	$ 1,788,197

(1 long-term debt is categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 15.

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

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, 2015, and 2014, (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI Year Ended December 31,	
	2015	2014
Unrealized gains on available-for-sale securities		
Realized gain on sale of securities, before tax(1)	$	$
Tax benefit(2)	—	—
Net of tax	—	—
Amortization of defined benefit pension items(3)		
Prior service cost	185	220
Net loss	4,195	2,618
Total before tax	4,380	2,838
Tax benefit(2)	(1,712)	(1,110)
Net of tax	2,668	1,728
Total reclassification for the period	$ 2,668	$ 1,728

(1) The realized gain is included in Idaho Power's consolidated income statement in other income (expense), net.

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

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

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 $0.9 million in 2015 and $1.4 million in 2014.

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 2015 and $9 million in 2014.

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	04/15/2016	End of 2015/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,485,463,707	5,485,463,707
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,485,463,707	5,485,463,707
9	Leased to Others		
10	Held for Future Use	7,090,431	7,090,431
11	Construction Work in Progress	396,931,372	396,931,372
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,889,485,510	5,889,485,510
14	Accum Prov for Depr, Amort, & Depl	2,097,432,010	2,097,432,010
15	Net Utility Plant (13 less 14)	3,792,053,500	3,792,053,500
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,071,784,276	2,071,784,276
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	25,647,734	25,647,734
22	Total In Service (18 thru 21)	2,097,432,010	2,097,432,010
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)	2,097,432,010	2,097,432,010

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	04/15/2016	End of 2015/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	29,296,781	462,901
4	(303) Miscellaneous Intangible Plant	29,627,507	3,479,891
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	58,929,991	3,942,792
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,712,208	18,263
9	(311) Structures and Improvements	150,084,364	3,911,857
10	(312) Boiler Plant Equipment	595,163,147	100,272,650
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	159,336,727	13,999,188
13	(315) Accessory Electric Equipment	70,043,047	816,126
14	(316) Misc. Power Plant Equipment	15,934,815	2,104,268
15	(317) Asset Retirement Costs for Steam Production	6,372,118	7,557,943
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	998,646,426	128,680,295
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	31,188,341	35,573
28	(331) Structures and Improvements	175,002,423	1,215,068
29	(332) Reservoirs, Dams, and Waterways	262,578,901	7,483,596
30	(333) Water Wheels, Turbines, and Generators	207,190,561	5,110,769
31	(334) Accessory Electric Equipment	56,827,891	1,778,270
32	(335) Misc. Power PLant Equipment	21,769,922	1,140,922
33	(336) Roads, Railroads, and Bridges	9,584,640	1,295,862
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	764,142,679	18,060,060
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	140,902,354	1,808,711
39	(342) Fuel Holders, Products, and Accessories	10,452,547	
40	(343) Prime Movers	238,896,447	858,744
41	(344) Generators	66,355,256	176,620
42	(345) Accessory Electric Equipment	88,607,565	2,591,423
43	(346) Misc. Power Plant Equipment	6,247,393	-236,918
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	554,151,568	5,198,580
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,316,940,673	151,938,935

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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
			29,759,682		3
4,613,599			28,493,799		4
4,613,599			58,259,184		5
					6
					7
			1,730,471		8
587,492			153,408,729		9
12,546,647			682,889,150		10
					11
10,791,836			162,544,079		12
157,384			70,701,789		13
535,197			17,503,886		14
			13,930,061		15
24,618,556			1,102,708,165		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,223,914		27
221,120			175,996,371		28
102,655			269,959,842		29
621,974			211,679,356		30
131,843			58,474,318		31
114,581			22,796,263		32
			10,880,502		33
					34
1,192,173			781,010,566		35
					36
			2,690,006		37
			142,711,065		38
			10,452,547		39
20,794,299			218,960,892		40
			66,531,876		41
100,000			91,098,988		42
			6,010,475		43
					44
20,894,299			538,455,849		45
46,705,028			2,422,174,580		46

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	04/15/2016	End of 2015/Q4

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	36,146,124	232,955
49	(352) Structures and Improvements	72,737,991	5,128,194
50	(353) Station Equipment	399,787,968	11,017,730
51	(354) Towers and Fixtures	168,186,852	16,612,039
52	(355) Poles and Fixtures	142,597,655	16,669,245
53	(356) Overhead Conductors and Devices	196,360,600	16,587,047
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)	1,016,207,456	66,247,210
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,175,131	125,393
61	(361) Structures and Improvements	33,716,699	493,837
62	(362) Station Equipment	202,030,200	16,141,880
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	241,088,379	8,202,243
65	(365) Overhead Conductors and Devices	128,008,024	3,488,928
66	(366) Underground Conduit	47,294,326	1,240,181
67	(367) Underground Conductors and Devices	218,656,607	13,091,098
68	(368) Line Transformers	494,614,876	28,686,286
69	(369) Services	57,867,385	1,245,760
70	(370) Meters	80,528,574	4,777,999
71	(371) Installations on Customer Premises	2,914,525	111,792
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,504,500	89,586
74	(374) Asset Retirement Costs for Distribution Plant	533,712	-369,521
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,516,932,938	77,325,462
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	
87	(390) Structures and Improvements	107,038,338	6,306,655
88	(391) Office Furniture and Equipment	45,902,762	4,656,977
89	(392) Transportation Equipment	74,214,375	8,247,219
90	(393) Stores Equipment	1,936,397	359,137
91	(394) Tools, Shop and Garage Equipment	7,574,780	602,385
92	(395) Laboratory Equipment	12,652,489	396,754
93	(396) Power Operated Equipment	13,938,120	1,923,220
94	(397) Communication Equipment	53,788,304	3,488,278
95	(398) Miscellaneous Equipment	5,577,125	511,022
96	SUBTOTAL (Enter Total of lines 86 thru 95)	339,201,272	26,491,647
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)	339,201,272	26,491,647
100	TOTAL (Accounts 101 and 106)	5,248,212,330	325,946,046
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)	5,248,212,330	325,946,046

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	04/15/2016	End of 2015/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
			36,379,079		48
85,939			77,780,246		49
3,203,069			407,602,629		50
170,836			184,628,055		51
886,706			158,380,194		52
1,042,990			211,904,657		53
					54
					55
			390,266		56
					57
5,389,540			1,077,065,126		58
					59
			5,300,524		60
35,183			34,175,353		61
1,318,351			216,853,729		62
					63
2,304,956			246,985,666		64
2,165,484			129,331,468		65
211,898			48,322,609		66
1,604,537			230,143,168		67
7,648,883			515,652,279		68
342,381			58,770,764		69
59,115			85,247,458		70
71,859			2,954,458		71
					72
50,837			4,543,249		73
			164,191		74
15,813,484			1,578,444,916		75
					76
					77
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					80
					81
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					83
					84
					85
			16,578,582		86
2,420,337			110,924,656		87
3,867,656			46,692,083		88
6,582,731			75,878,863		89
40,131			2,255,403		90
155,609			8,021,556		91
345,424			12,703,819		92
779,305			15,082,035		93
1,861,382			55,415,200		94
120,443			5,967,704		95
16,173,018			349,519,901		96
					97
					98
16,173,018			349,519,901		99
88,694,669			5,485,463,707		100
					101
					102
					103
88,694,669			5,485,463,707		104

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	04/15/2016	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		655,550
3	Production			109,961
4	Transmission Stations			423,089
5	Transmission Lines			195,489
6	Distribution Stations			1,077,217
7	Beacon Light Substation	12/30/02		465,662
8	Homedale Substation	2/29/08		109,453
9	North River Operations Center	1/31/08		2,630,412
10	Line #854 500 Kv	3/31/09		308,066
11				
12				
13				
14	Column B if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Transmission Stations			199,069
24	Distribution Stations			69,941
25	Homedale Substation	2/29/08		217,797
26	Beacon Light Substation	12/30/02		555,940
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45				
46				
47	Total			7,090,431

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	04/15/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ROLLUP RELIC COST BROWNLEE	86,963,920
2	ROLLUP RELIC COST HELLS CANYON	59,261,154
3	BRIDGER 2011C039 JB4 SCR SYS D	37,547,331
4	GATEWAY WEST 500KV LINE	29,199,462
5	ROLLUP RELIC COST OXBOW	27,524,739
6	HELLS CANYON RELICENSING OUTSI	22,519,224
7	BOARDMAN - HEMINGWAY 500 KV LI	11,567,064
8	B2H PERMITTING 11/1/2011 & FOR	9,853,267
9	BROWNLEE TURBINE REFURBISHMENT	9,811,096
10	LOWER SALMON RUNNER REPLACEMEN	6,896,703
11	BROWNLEE UNIT 1 TURBINE REFURB	6,339,392
12	HCC WATERSHED ENHANCEMENT PROG	3,816,660
13	LEGAL DEPT. LABOR FOR RELICENS	3,285,241
14	BRIDGER UNDISTRIBUTED WORK ORD	3,283,000
15	REL-HCC OREGON REAUTHORIZATION	2,654,393
16	B2H TLINE CONSTRUCTION COSTS	2,479,755
17	MPSN T501 - REPLACE FAILED 500	2,362,687
18	REWIND GENERATOR STATOR #4	2,136,864
19	WQ HCC401 CERTIFICATION OPS AN	1,982,499
20	WDRI-KCHM NEW 138KV	1,643,935
21	WQ HCC401 APPLICATION, REVISIO	1,566,482
22	FALL CHINOOK PROGRAM - REDD SU	1,410,685
23	HBND-041:ALT LINE ROUTE TO GAR	1,405,061
24	RELICENSING: BAKER COUNTY SETT	1,380,185
25	T216 7.1 MILES OF 69KV LINE FR	1,353,368
26	BRIDGER 2015C070 U4 REPLACE FI	1,315,646
27	REC - BAKER COUNTY SETTLEMENT	1,260,702
28	HEMINGWAY 500 KV IN AND OUT RE	1,233,651
29	T4331001-UPGRADE T433 TO 230KV	1,203,508
30	314 DESIGN TEAMS - CAPITAL - C	1,112,931
31	BULL TROUT PROGRAM - ADMINISTR	1,109,406
32	METEOROLOGY MODEL FOR OPERATIO	1,079,859
33	BROWNLEE UNIT 3 TURBINE REFURB	1,004,404
34	OTHER MINOR PROJECTS UNDER $1,000,000	49,367,098
35		
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42		
43	TOTAL	396,931,372

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	04/15/2016	End of 2015/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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	1,997,908,418	1,997,908,418		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	130,382,128	130,382,128		
4	(403.1) Depreciation Expense for Asset Retirement Costs	549,017	549,017		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,896,082	3,896,082		
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)	134,929,440	134,929,440		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	84,081,070	84,081,070		
13	Cost of Removal	13,728,966	13,728,966		
14	Salvage (Credit)	26,189,699	26,189,699		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	71,620,337	71,620,337		
16	Other Debit or Cr. Items (Describe, details in footnote):	10,566,755	10,566,755		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,071,784,276	2,071,784,276		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	540,252,070	540,252,070		
21	Nuclear Production				
22	Hydraulic Production-Conventional	402,629,313	402,629,313		
23	Hydraulic Production-Pumped Storage				
24	Other Production	90,194,940	90,194,940		
25	Transmission	337,675,154	337,675,154		
26	Distribution	590,665,462	590,665,462		
27	Regional Transmission and Market Operation				
28	General	110,367,337	110,367,337		
29	TOTAL (Enter Total of lines 20 thru 28)	2,071,784,276	2,071,784,276		

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

CIAC, Reserve Adjustments and Asset Retirement Obligation activity.

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	04/15/2016	End of 2015/Q4

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			81,014,366
5				
6	Subtotal Idaho Energy Resources Company			83,477,460
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41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	83,477,460

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
6,659,942	6,000,000	81,674,307		4
				5
6,659,942	6,000,000	84,137,401		6
				7
				8
				9
				10
				11
				12
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				41
6,659,942	6,000,000	84,137,401		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	04/15/2016	End of 2015/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)	55,170,482	61,818,257	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	599		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)	17,010,420	17,384,869	
8	Transmission Plant (Estimated)	11,212,105	11,191,094	
9	Distribution Plant (Estimated)	20,564,459	21,957,543	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,518,495	1,911,722	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	50,305,479	52,445,228	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)	5,098,760	4,478,320	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	110,575,320	118,741,805	

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	04/15/2016	End of 2015/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 78318516	12,245	186623	(7,270)	186623
3	BPAP TRANS SIS 80289606		186623	8,169	186623
4	PAC PTP SIS 80381517	2,367	186623	7,633	186623
5					
6					
7					
8					
9					
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13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LAGOON SOLAR #490	1,624	186623.00000	(1,624)	186623.00000
23	LITTLE VALLEY SOLAR 491	3,571	186623.00000	(11,430)	186623.00000
24	ACADIA SOLAR #474	5,095	186623.00000	(5,095)	186623.00000
25	ADA PV2-A #482	15,932	186623.00000	(15,932)	186623.00000
26	ADA PV2-B #483	14,796	186623.00000	(14,796)	186623.00000
27	AMERICAN FALLS SOLAR # 431	35,941	186623.00000	(26,415)	186623.00000
28	AMERICAN FALLS SOLAR II # 433	20,518	186623.00000	(13,735)	186623.00000
29	BAKER SOLAR 1 #507	1,046	186623.00000	(1,000)	186623.00000
30	BAKER SOLAR 2 #508	1,047	186623.00000	(1,000)	186623.00000
31	BENSON CREEK WINDFARM GI 401		186623.00000	85,666	186623.00000
32	BIG DOG SOLAR #470	5,024	186623.00000	(5,024)	186623.00000
33	BOISE CITY SOLAR #432	34,164	186623.00000	(65,289)	186623.00000
34	BRUSH SOLAR #500	914	186623.00000	(914)	186623.00000
35	BUTLER SOLAR #471	3,872	186623.00000	(3,872)	186623.00000
36	CHERRY LANE SOLAR #462 10MW	709	186623.00000	(709)	186623.00000
37	CLARK 2 SOLAR-20MW #438	9,001	186623.00000	(8,086)	186623.00000
38	CLARK 4 SOLAR-20MW #440	8,908	186623.00000	(7,993)	186623.00000
39	CLARK SOLAR 1 #437 7MW	13,763	186623.00000	(4,620)	186623.00000
40	CLARK SOLAR 3 #439 30MW	10,267	186623.00000	(437)	186623.00000

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	04/15/2016	End of 2015/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**				
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20					
21	**Generation Studies**				
22	COOPER SOLAR #478	2,184	186623.00000	(2,184)	186623.00000
23	DAVIS SOLAR # 506	1,102	186623.00000	(1,000)	186623.00000
24	DAVIS SOLAR #498	207	186623.00000	(207)	186623.00000
25	DURKEE SOLAR #496	1,630	186623.00000	(1,630)	186623.00000
26	EVERGREEN SOLAR #475	8,020	186623.00000	(43,964)	186623.00000
27	FAIRWAY SOLAR #493	5,601	186623.00000	(12,933)	186623.00000
28	FALLS CITY SOLAR #461 10MW	1,568	186623.00000	(1,568)	186623.00000
29	FOURTH AVE. SOLAR #481	2,849	186623.00000	(2,849)	186623.00000
30	GRANDVIEW PV SOLAR FIVE GI 411		186623.00000	1,578	186623.00000
31	GROVE SOLAR CENTER - GI 414	1,753	186623.00000	20,351	186623.00000
32	HUNTINGTON SOLAR 1 #505	954	186623.00000	(1,000)	186623.00000
33	HYLINE SOLAR CENTER - GI 419	4,177	186623.00000	10,942	186623.00000
34	IPCL TRANS SIS 80914710	1,025	186623.00000	(1,025)	186623.00000
35	JACKPOT SOLAR NORTH #502	9,446	186623.00000	(11,000)	186623.00000
36	JACKPOT SOLAR SOUTH #503	9,631	186623.00000	(11,000)	186623.00000
37	JAMIESON SOLAR #472	5,830	186623.00000	(5,830)	186623.00000
38	JOHN DAY SOLAR #480	4,822	186623.00000	(44,324)	186623.00000
39	KINGMAN SOLAR 489	2,794	186623.00000	(2,794)	186623.00000
40	LUTHER SOLAR #492	324	186623.00000	(324)	186623.00000

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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**				
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20					
21	**Generation Studies**				
22	MAHLHUER RIVER SOLAR #477	5,776	186623.00000	(32,689)	186623.00000
23	MERIDIAN/NORTH RD PV1-A	1,958	186623.00000	(11,518)	186623.00000
24	MERIDIAN/NORTH RD PV1-B #485	1,581	186623.00000	(1,581)	186623.00000
25	MOORES HOLLOW #476	6,610	186623.00000	(42,981)	186623.00000
26	MORTH GOODING MAIN HYDRO #494	3,494	186623.00000	(25,075)	186623.00000
27	MOUTAIN HOME SOLAR-20MW #435	29,563	186623.00000	(47,195)	186623.00000
28	MT. HOME SOLAR #444	1,211	186623.00000	(211)	186623.00000
29	MURPHY FLAT POWER NORTH #426	42,708	186623.00000	(37,772)	186623.00000
30	MURPHY FLAT POWER SOUTH #427		186623.00000	(2,540)	186623.00000
31	OLD FERRY ROAD SOLAR #473	8,743	186623.00000	(44,281)	186623.00000
32	ONTARIO SOLAR #504	1,013	186623.00000	(1,000)	186623.00000
33	OPEN RANGE SOLAR CENTER - GI 413	1,681	186623.00000	8,737	186623.00000
34	ORCHARD RANCH 2 #488		186623.00000	(10,000)	186623.00000
35	ORCHARD RANCH SOLAR-20MW #441	37,093	186623.00000	(52,867)	186623.00000
36	OWYHEE SOLAR #479	5,750	186623.00000	(5,750)	186623.00000
37	POCATELLO SOLAR-20MW #436	15,230	186623.00000	(33,041)	186623.00000
38	RAILROAD SOLAR CENTER - GI 423	9,127	186623.00000	16,063	186623.00000
39	RAILROAD SOLAR CENTER - GI 424	5,281	186623.00000	13,759	186623.00000
40	SALMON RIVER CANAL 550KW		186623.00000	(534)	186623.00000

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					
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20					
21	**Generation Studies**				
22	SIDDOWAY SOLAR #486	3,352	186623.00000	(3,352)	186623.00000
23	SIMCO SOLAR #442	2,985	186623.00000	(1,985)	186623.00000
24	SIMCOE SOLAR 2 # 487	7,192	186623.00000	(50,000)	186623.00000
25	SIMCOE SOLAR CENTER #428	37,638	186623.00000	(42,822)	186623.00000
26	SOUTHERN IDAHO SOLID WASTE #501	1,776	186623.00000	(11,000)	186623.00000
27	SUTTON CREEK SOLAR #495	1,457	186623.00000	(10,329)	186623.00000
28	TILLI SOLAR #443	1,599	186623.00000	(599)	186623.00000
29	VALE AIR SOLAR CENTER - GI 412	1,711	186623.00000	12,056	186623.00000
30	VALLEY LANE SOLAR PV1	2,697	186623.00000	(2,697)	186623.00000
31	WEGNER SOLAR #499	329	186623.00000	(1,000)	186623.00000
32	WRIGHT PLACE SOLAR #445	3,463	186623.00000	(2,463)	186623.00000
33	ZEHR SOLAR #497	1,694	186623.00000	(1,694)	186623.00000
34					
35					
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Schedule Page: 231 Line No.: 22 Column: d

Amounts represent both reimbursements received and refunds back to the counterparties. Refunds are initiated when the final expenses exceed the intial deposit received.

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	04/15/2016	End of 2015/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	Asset Retirement Obligations (182341)	17,033,635	363,196	Various	3,216,060	14,180,771
2	IPUC Order #29414-OPUC Order #04-585					
3						
4	ASC 815 Mark to Market (182330 & 182333)	3,960,704	18,595,015	244	17,583,119	4,972,600
5	IPUC Order #28661					
6						
7	FAS 109 Unfunded (182322)	802,188,345	87,385,943	382	14,546,806	875,027,482
8	Accum Deferred Income Noncurrent					
9						
10	PCA Deferral Idaho - IPUC Order #33306	45,412,570	59,429,323	401	55,501,666	49,340,227
11	(Amort period 06/16 thru 05/17) (182323)					
12						
13	PCA Prior Year Deferral Idaho - IPUC Order #33049	12,535,848	34,627,781	401	47,160,880	2,749
14	(Amort period 06/15 thru 05/16) (182324)					
15						
16	Fixed Cost Adjustment (FCA) (182302)	16,811,911	31,393,901	1823	20,266,964	27,938,848
17	IPUC Order #33302 (Amort period 06/16 thru 05/17)					
18						
19	Prior Year FCA IPUC Order #33047 (182309)	6,925,678	25,831,710	400	24,932,619	7,824,769
20	(Amort period 6/15 thru 5/16)					
21						
22	AOCI Impact of Unfunded Post Retirement Liability	903,788	117	2283	2,428,321	-1,524,416
23	IPUC Order #30256 (182306)					
24						
25	Oregon Pension Expense Capitalized (182339)	2,750,366	611,255	4073	94,960	3,266,661
26	OPUC Order #10-064 (Amort period thru 2052)					
27						
28	Deferred Pension Expense Net of Contributions	20,077,507	39,659,896	Various	38,532,812	21,204,591
29	IPUC Order #30333 (182321)					
30						
31	AOCI Impact of Unfunded Pension Liability	263,644,763	4,999,578	2283	15,358,112	253,286,229
32	IPUC Order #30256 (182320)					
33						
34	PCA Unbilled Forecast (182325)	(1,055,813)	19,463,835	401	20,525,175	-2,117,153
35						
36	PCAM Oregon 2008 (182346)	5,534,507	121,552	401	2,424,616	3,231,443
37	OPUC Order #08-238 & #13-439 (Amort 1/14 - 6/17)					
38						
39	PCAM Interest Reserve 2008 (182329)	(568,429)	237,936			-330,493
40	(Amort 1/14 - 6/17)					
41						
42	PCA SBA Unbilled Adj (182326)		33,645,247	401	35,104,595	-1,459,348
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	04/15/2016	End of 2015/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	FCA Calender Mo Adj IPUC Order (182308)		26,687,947	400	25,631,172	1,056,775
2						
3	Idaho Boardman Decomissioning (182493)	1,217,507	5,674,701	Various	5,478,565	1,413,643
4	IPUC Order #32549 & #32457					
5						
6	Idaho Pension Cash IPUC Order #32248 (182327)	40,816,708	37,690,655	401	17,188,437	61,318,926
7	(Amort period beginning 06/11 thru unknown)					
8						
9	2008 PCAM Unbilled Amort (182356)	(158,302)	1,812,976	401	1,820,146	-165,472
10	(Amort period 1/14 thru 6/17)					
11						
12	Lidar Surveys IPUC Order #32426 (182361)	305,233		402	43,605	261,628
13	(Amort period 01/12 thru 12/21)					
14						
15	PCA Unbilled Amortization (182316)	(2,380,650)	44,612,555	400, 401	43,441,968	-1,210,063
16	(Amort period 06/15 thru 05/16)					
17						
18	Idaho Boardman ARO IPUC Order #29414 (182393)	261,340		4110, 4031	43,557	217,783
19	(Amort period thru 2020)					
20						
21	Langley Revenue Accrual IPUC Order #12-226 (182398)	941,957	75,471			1,017,428
22						
23	Other RA-PS&I Shoshone Order #29904 (182368)		800,373	401	133,395	666,978
24						
25	RA-OATT Deferral-IPUC Order #33313 (182350)		1,083,701			1,083,701
26						
27	RA-OR CUB Fund Amort 15-399 (182386)		272,714			272,714
28	(Amort period 1/16 thru 5/17)					
29						
30	RA-SIEMENS LTP DEF RB 33420 (182410)		11,632,907			11,632,907
31	(Amort period 1/16 thru 12/42)					
32						
33	RA-SIEMENS LTP RB 33420 (182411)		17,358,636			17,358,636
34	(Amort period 1/16 thru 12/42)					
35						
36	RA-SIEMENS LTP DEF RB 15-387 (182412)		446,876			446,876
37	(Amort period 1/16 thru 12/42)					
38						
39	RA-SIEMENS LTP RB 15-387 (182413)		786,315			786,315
40	(Amort period 1/16 thru 12/42)					
41						
42	Bennett Mtn Maintenance IPUC ORder #32426	74,887		402	74,887	
43	(Amort period 01/12 thru 12/15) (182379)					

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	04/15/2016	End of 2015/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	OATT Revenue Deferred Reserve (182336)	286,732			286,732	
2	IPUC Order #30940 (Amort period 6/12 thru 5/15)					
3						
4	Oregon DSM Rider - (182405)		4,482,485	Various		4,482,485
5	Advice #05-03					
6						
7	Minor Items (36)	302,932	312,390	Various	529,414	85,908
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43						
44	**TOTAL :**	1,237,823,724	510,096,987		392,348,583	1,355,572,128

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	04/15/2016	End of 2015/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)	669,396	1,716,012	165, 431	1,340,926	1,044,482
2	(Amort period 11/16 thru 11/20)					
3						
4	Prepaid Service Contract	1,659,405	556,171	Various	1,461,732	753,844
5	Long Term Portion (186052)					
6						
7	Long Term (186121)	1,130,749		2282,401	61,090	1,069,659
8	Workers Compensation					
9						
10	Prepaid ROW (186160)	425,944		401	42,970	382,974
11	Rents/Easements Long Term					
12						
13	Long-Term Portfolio (186255)	1,791,148	5,070,889	165, 402	5,768,411	1,093,626
14						
15	OATT Reserve (186350)			400	1,083,701	-1,083,701
16						
17	Advance Prepaid (186709)	1,241,610		151	71,478	1,170,132
18	Coal Royalties					
19						
20	Stable Value Life (186719)		30,004,992			30,004,992
21						
22	Security Plan (186720)	20,059,079	324,769	143,4262	5,613,855	14,769,993
23	Net Insurance Asset					
24						
25	American Falls Bond Ref(186722)	147,948		401	14,553	133,395
26	(Amort Period 04/00 thru 02/25)					
27						
28	Retiree Medical-COLI (186726)	3,834,224	1,128,996	143,4262	1,171,972	3,791,248
29						
30	American Falls Water Rights	10,506,922		401	1,042,009	9,464,913
31	(amort 01/06 - 02/25) (186727)					
32						
33	Shelf Registration (186732)	160,469	2,416,222	181	2,576,691	
34						
35	Milner Bond Guarantee (186734)	3,190,909		253	1,063,636	2,127,273
36	(Amort 02/07 - 2/17)					
37						
38	American Falls - Bond Refinance	487,991		401	47,999	439,992
39	(Amort through 02/25) (186770)					
40						
41	Power Plant - Bridger (186780)	254,793		401	127,396	127,397
42	(Amort thru 06/14 thru 12/16)					
43						
44	Bridger Coal Study (186781)		3,932,864	107, 401	2,527,077	1,405,787
45						
46	Minor Items (3)	4,126	2,777,223	Various	2,776,060	5,289
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,564,713				66,701,295

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	04/15/2016	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5	Other Electric (See footnote)	97,597,101	**83,181,338**
6			
7	Other (See footnote)	169,747,033	**163,213,808**
8	TOTAL Electric (Enter Total of lines 2 thru 7)	267,344,134	246,395,146
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	21,759,450	**23,793,249**
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	289,103,584	270,188,395

Notes

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

	Beginning Balance	Ending Balance
Prov for Rate Refund-HC Relicensing (AFUDC)	28,529,481	34,282,231
Regulatory Asset-Non Current	18,067,486	-
Deferred Idaho ITC	17,378,549	19,624,338
VEBA-Post Retirement Benefits	10,617,384	11,343,166
Incentive Deferral-Profit Sharing-Not in Rates	5,085,262	3,814,372
Stock Based Compensation-FAS 123R	3,782,196	3,813,934
Revenue Sharing	3,127,266	1,235,198
Pension Expense-Oregon	2,488,771	3,008,600
Rate Case Disallowance	2,273,741	2,273,741
Regulatory Liability-Current	1,918,442	-
Construction Advances	1,016,324	1,637,625
Valmy Union Pacific Contract	919,072	-
Asset Retirement Obligation (ARO)	865,690	1,171,048
M & E Reserve	592,049	-
Postretirement Benefits-FAS 112	568,869	486,873
Bridger Revenue Deferral	316,603	316,603
Executive Deferred Compensation	54,988	39,761
Deferred GBC Federal	31,500	31,500
USBR-American Falls O&M Costs Settlement	-	138,920
Non-VEBA Pension and Benefits	(36,572)	(36,572)
Total Other Electric	97,597,101	83,181,338

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

	Beginning Balance	Ending Balance
Pension-FAS 158	103,071,920	99,022,251
Regulatory Asset-FAS 109	50,814,726	51,130,605
Minimum Pension Liability	15,507,051	13,656,923
Postretirement Plan-FAS 158	353,336	(595,971)
Total Other	169,747,033	163,213,808

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

	Beginning Balance	Ending Balance
Senior Management Security Plan	21,402,608	23,635,408
Micron CIAC-Depr Timing Diff	336,836	153,366
Meridian Gold CIAC-Depr Timing Diff	20,006	4,475
Total Non Electric	21,759,450	23,793,249

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	04/15/2016	End of 2015/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			
7				
8				
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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) 04/15/2016	Year/Period of Report End of 2015/Q4

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
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						42

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	
9		
10		
11		
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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	04/15/2016	End of 2015/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		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
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21		
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	04/15/2016	End of 2015/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	31,181,894

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	04/15/2016	End of 2015/Q4

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	100,000,000	6,150,000	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
				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/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	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	6.025 % Series Due 2018	120,000,000	1,630,120
17			
18	4.30% Series Due 2042	75,000,000	802,240
19			49,417 D
20			
21	2.95% Series Due 2022	75,000,000	708,490
22			127,607 D
23			
24	3.68% Series Due 2045	250,000,000	2,559,510
25			1,715,000 D
26			
27	Subtotal Account 221	1,845,460,000	31,181,894
28			
29	Account 222 - Reaquired Bonds		
30			
31	Account 223: Advances for Associated Companies		
32			
33	TOTAL	1,877,045,000	31,181,894

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	14,841	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
7/10/08	7/15/18	7/10/08	7/15/08		2,249,333	16
						17
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	18
						19
						20
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	21
						22
						23
3/6/15	3/1/45	3/6/15	3/1/45	250,000,000	7,477,431	24
						25
						26
				1,725,460,000	83,055,805	27
						28
						29
						30
						31
						32
				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/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 224:		
2	Bond Guarantee - American Falls	19,885,000	
3	Note Guarantee - Milner Dam	11,700,000	
4	Subtotal Account 224	31,585,000	
5			
6			
7			
8			
9			
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31			
32			
33	TOTAL	1,877,045,000	31,181,894

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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
04/26/00	2/1/25			19,885,000		2
02/10/92				2,127,273		3
				22,012,273		4
						5
						6
						7
						8
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				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/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)	190,983,483
2		
3		
4	Taxable Income Not Reported on Books	
5		34,015,846
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-2,121,812
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		29,665,225
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		168,047,554
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	25,164,738
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	8,807,658
30		
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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	04/15/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

4005-AVOIDED COST	7,692,969
4003-CONSTRUCTION ADVANCES	1,775,147
4013-CIAC - TAXABLE - ACCT 107	(5,362,106)
4021-ENGINEERING FEES - TAXABLE - ACCT 107	(109,771)
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	451,208
4506-MERIDIAN GOLD CIAC - DEPR TIMING DIFF - NON-OP	(39,726)
4507-MICRON CIAC - DEPR TIMING DIFF - NON-OP	(469,295)
GAIN ON PAC LIKE KIND EXCHANGE	13,052,859
GAIN ON SALE OF SPARE PARTS TO SIEMENS	17,024,561
Total	**34,015,846**

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

Total Federal and State taxes deducted on books	**45,111,128**
5001-BAD DEBT EXPENSE	(2,022,198)
5024-NON-DEDUCTIBLE MEALS	500,000
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	1,109,555
5022-263A CAPITALIZED OVERHEADS	(25,000,000)
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	534,181
5010-POSTEMPLOYMENT BENEFITS-SFAS112	(209,735)
5023-PENSION EXPENSE	(21,846,287)
5035-PCA EXPENSE DEFERRAL	9,955,542
5046-EXECUTIVE DEFERRED COMP - ST	(32,425)
5047-EXECUTIVE DEFERRED COMP - LT	(6,524)
5053-STOCK BASED COMPENSATION - FAS 123R	80,979
5058-FIXED COST ADJUSTMENT	(13,082,804)
5060-OREGON - PCAM	2,072,297
5061-PENSION EXPENSE - OREGON	1,329,658
5065-VALMY UNION PACIFIC CONTRACT	(2,350,868)
5067-ASSET RETIREMENT OBLIGATION (ARO)	781,066
5069-M & E RESERVE	(1,514,386)
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	(3,250,774)
5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST	8,566
5505-SMSP - NET	5,711,217
Total	**(2,121,812)**

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

7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	6,659,942
7509-SMSP - INSURANCE PROCEEDS	1,286,474
7502-ALLOWANCE FOR OFUDC	21,785,246
7503-ALLOWANCE FOR BFUDC	10,043,775
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	(14,714,797)
7011-OATT REVENUE DEFICIENCY	(286,732)
7012-REVENUE SHARING	4,839,667
7013-LANGLEY REVENUE ACCRUAL	51,650
Total	**29,665,225**

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

8025-MANUFACTURING DEDUCTION	2,776,466
8034-REMOVAL COSTS	13,735,582
8042-GAIN/LOSS ON REACQUIRED DEBT	16,931,184

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8073-REPAIRS DEDUCTION	82,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES	256,232
8001-VEBA - POST RETIREMENT BENEFITS	(1,926,786)
8020-CONSERVATION EXPENSES	638,796
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107	1,000,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	2,800,000
8009-DEPR TIMING DIFF - OPERATING - FEDERAL	42,953,555
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	6,882,525
Total	**168,047,554**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	-17,861,172		13,222,719	546,919	
3	Social Security - (FOAB)	-1,179		14,633,862	14,633,217	
4	Unemployment			93,143	93,143	
5	Subtotal Federal	-17,862,351		27,949,724	15,273,279	
6						
7	State of Idaho:					
8	Property	9,028,370		21,603,531	21,196,819	-15
9	Non-Operating	11,508		19,188	20,350	
10	Income	-2,913,887		5,454,898	2,799,259	
11	KWH	86,152		1,465,259	1,458,487	
12	Unemployment			557,293	557,293	
13	Regulatory Commission			2,842,553	2,842,553	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	6,212,143		31,942,872	28,874,911	-15
16						
17	State of Oregon					
18	Property		1,435,643	2,974,336	3,135,491	
19	Non-Operating Property		918	1,867		
20	Income	-171,566		268,067	203,277	
21	Regulatory Commission			206,569	206,569	
22	Unemployment			52,232	53,089	
23	Franchise	205,949		824,997	833,458	
24	Subtotal Oregon	34,383	1,436,561	4,328,068	4,431,884	
25						
26	State of Montana:					
27	Property	161,411		339,510	331,295	
28	Subtotal Montana	161,411		339,510	331,295	
29						
30	State of Nevada:					
31	Property		502,346	1,063,273	1,097,236	
32	Subtotal Nevada		502,346	1,063,273	1,097,236	
33						
34	State of Wyoming					
35	Corporate License			4,843	4,843	
36	Property	802,464		1,627,460	1,614,781	
37	Subtotal Wyoming	802,464		1,632,303	1,619,624	
38						
39						
40						
41	TOTAL	-10,635,253	1,938,907	51,966,919	51,674,868	5,823

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	04/15/2016	End of 2015/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 (l) 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
(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)	No.
						1
-5,185,372		12,593,365			629,354	2
-534		14,633,862				3
		93,143				4
-5,185,906		27,320,370			629,354	5
						6
						7
9,435,081		21,602,678			853	8
10,346					19,188	9
-258,247		5,656,832			-201,934	10
92,925		1,465,259				11
		557,293				12
		2,842,553				13
		150				14
9,280,105		32,124,765			-181,893	15
						16
						17
	1,596,798	2,830,399			143,937	18
	948				1,867	19
-106,776		277,503			-9,436	20
		206,569				21
-857		52,232				22
197,487		824,997				23
89,854	1,597,746	4,191,700			136,368	24
						25
						26
169,627		339,510				27
169,627		339,510				28
						29
						30
	536,309	1,063,273				31
	536,309	1,063,273				32
						33
						34
		4,843				35
815,142		1,627,460				36
815,142		1,632,303				37
						38
						39
						40
5,192,418	2,134,055	51,387,776			579,143	41

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	04/15/2016	End of 2015/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			610	610	
3	Subtotal Washington			610	610	
4						
5	Other States Income	-17,398		47,089	-1,825	
6	Payroll Tax Credit			-15,336,530		
7	Canada GST tax	34,095			47,854	5,838
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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39						
40						
41	TOTAL	-10,635,253	1,938,907	51,966,919	51,674,868	5,823

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	04/15/2016	End of 2015/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 (l) 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
		610				2
		610				3
						4
31,516		51,775			-4,686	5
		-15,336,530				6
-7,920						7
						8
						9
						10
						11
						12
						13
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						40
5,192,418	2,134,055	51,387,776			579,143	41

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

```
Account 409.2      $    353,061
Account 234.020      (1,485,757)
Account 182.410        1,762,050
                   -------------
Total              $    629,354
                   =============
```

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

Miscellaneous Rounding

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

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Account 107        $        853
```

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

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Account 408.2      $     19,188
```

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

```
Account 409.2      $    65,362
Account 234.020       (267,296)
                   ------------
Total              $  (201,934)
                   ============
```

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

```
Account 107        $   143,937
```

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

```
Account 408.2      $     1,867
```

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

```
Account 409.2      $     4,155
Account 234.020        (13,591)
                   ------------
Total              $    (9,436)
                   ============
```

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

```
Account 409.2      $       (155)
Account 234.020          (4,531)
                   -------------
Total              $     (4,686)
                   =============
```

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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%	434,199				56,428	
4	7%						
5	10%	19,699,576				1,383,541	
6	11%	1,161,824				26,029	
7	Other- State	57,867,232	411.4	3,455,060	411.4	1,496,963	
8	TOTAL	79,162,831		3,455,060		2,962,961	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	57,867,232	411.4	3,455,060	411.4	1,496,963	
13							
14							
15							
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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	04/15/2016	End of 2015/Q4

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
377,771	7.69		3
			4
18,316,035	14.24		5
1,135,795	44.64		6
59,825,329	38.66		7
79,654,930			8
			9
			10
			11
59,825,329			12
			13
			14
			15
			16
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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	04/15/2016	End of 2015/Q4

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)	1,287,950	186, 242	8,854,688	9,625,463	2,058,725
2						
3	FTV (253202)	2,866,666	400	400,000		2,466,666
4	(Amort Period Mar 1998-Feb 2023)					
5						
6	Sho Ban Trans ROW (253480)	202,500	242	15,000		187,500
7	(Amort Period Jan 2005-Dec 2027)					
8						
9	Operations Accrual (253550)	1,271,388	232, 401	66,776	88,641	1,293,253
10	(amort period 1 year for dues)					
11						
12	Milner Falling Water (253953)	667,185	186	1,190,450	1,237,096	713,831
13	Amort Period (Feb 1992 - Feb 2017)					
14						
15	Postretirement Benefits (253960)	1,455,093	253, 401	1,455,093	1,245,358	1,245,358
16						
17	Directors Deferred Compensation	3,883,100	131	417,959	324,206	3,789,347
18	(253980-253999)					
19						
20	Minor Items (1) 253042	1,760	Various	59,403	60,961	3,318
21						
22						
23						
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46						
47	TOTAL	11,635,642		12,459,369	12,581,725	11,757,998

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	04/15/2016	End of 2015/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	451,117,692	41,997,682	18,235,837
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	451,117,692	41,997,682	18,235,837
6	Non-Operating Property			
7	Other - Regulatory Asset	797,512,669		
8	Like Kind Exchange- Reclass No			
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,248,630,361	41,997,682	18,235,837
10	Classification of TOTAL			
11	Federal Income Tax	1,071,548,840	41,671,931	18,118,546
12	State Income Tax	177,081,521	325,751	117,291
13	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		Balance at End of Year (k)	Line No.
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
	5,706,531	282.111	69,255			469,103,751	2
							3
							4
	5,706,531		69,255			469,103,751	5
							6
				182	77,514,814	875,027,483	7
5,706,531				282100	69,255	5,775,786	8
5,706,531	5,706,531		69,255		77,584,069	1,349,907,020	9
							10
5,706,531	5,706,531		69,255		61,569,691	1,156,602,661	11
					16,014,378	193,304,359	12
							13

NOTES (Continued)

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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) 04/15/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year: DR to 410.1 c	Changes during Year: CR to 411.1 d	Adjustments Debits: CR to 411.2 f	Adjustments Debits: Acct. credited g	Adjustments Debits: Amount h	2015 Ending Balance k
Line 2:	Depreciation Timing Diff-Operating	439,778,212	37,566,234	18,176,936	5,706,531	282.111	69,255	453,391,724
	Intangible-Labor Costs Deducted-Acct 107	17,382,911	965,708					18,348,619
	CIAC-Taxable-Acct 107	(6,010,733)	2,722,934					(3,287,799)
	Valmy Capitalized Items	121,766		58,206				63,560
	Software-Labor Costs Deducted-Acct 107	347,096	704,386					1,051,482
	Engineering Fees-Taxable-Acct 107	(501,560)	38,420	695				(463,835)
	TOTAL Line 2	451,117,692	41,997,682	18,235,837	5,706,531		69,255	469,103,751

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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	74,155,896	15,289,514	25,283,305
4				
5				
6				
7				
8	Other -- See Note	103,425,257		
9	TOTAL Electric (Total of lines 3 thru 8)	177,581,153	15,289,514	25,283,305
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	851,124		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	178,432,277	15,289,514	25,283,305
20	Classification of TOTAL			
21	Federal Income Tax	149,678,643	12,825,671	21,209,003
22	State Income Tax	28,753,634	2,463,843	4,074,302
23	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						64,162,105	3
							4
							5
							6
							7
		190	4,998,975			98,426,282	8
			4,998,975			162,588,387	9
							10
							11
							12
							13
							14
							15
							16
							17
6,080	538,968					318,236	18
6,080	538,968		4,998,975			162,906,623	19
							20
5,100	452,116		4,193,411			136,654,884	21
980	86,852		805,564			26,251,739	22
							23

NOTES (Continued)

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	2015 Ending Balance k
Line 3:	Pension Expense	18,934,259	8,729,744		27,664,003
	PCA Expense	21,311,448		3,892,119	17,419,329
	Conservation Expenses	1,789,468	249,737	305,813	1,733,392
	Fixed Cost Adjustment	9,280,211	5,114,722		14,394,933
	Regulatory Asset-Current	18,067,486		18,067,486	(0)
	Oregon PCAM	1,942,270		810,947	1,131,323
	Regulatory Liability-Non Current	1,918,442		1,918,442	0
	Boardman Decommission	484,201			484,201
	Oregon Excess Power Costs	(61,888)		0	(61,888)
	OATT Revenue Deficiency	112,098		112,098	0
	Renewable Energy Certificates (REC) Sales	(228,084)	1,150,343	176,400	745,859
	Langley Revenue Accrual	350,781	20,193		370,974
	2011 LIDAR Surveys Deferral	119,331			119,331
	Bennett Mtn Maint Deferral	29,277		0	29,277
	Intervenor Funding Orders	121,344	0		121,344
	OPUC Grid West Loans	925	0	0	925
	Emission Allowances	3,722	5,380		9,102
	Delivery Accruals	(19,395)	19,395		(0)
	TOTAL Line 3	74,155,896	15,289,514	25,283,305	64,162,105

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. credited g	Amount h	2015 Ending Balance k
Line 8:	Pension-FAS 158	103,071,921					190	4,049,669	99,022,252
	Postretirement Plan-FAS 158	353,336					190	949,306	(595,970)
	TOTAL Line 8	103,425,257	0	0	0	0		4,998,975	98,426,282

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. credited g	Amnt h	2015 Ending Balance k
Line 18:	EDC-Unrealized Gain/Loss From Rabbit Trust	543,030				538,610			4,420
	SMSP-Unrealized Gain/Loss From Rabbi Trust	(41,951)							(41,951)
	Royalty Income	349,687			5,721				355,408
	Oregon Non-Op Prop Tax Adj	358			359	358			359
	TOTAL Line 18	851,124	0	0	6,080	538,968		0	318,236

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	04/15/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Market to Market Short Term - (254001)	1,817,027	175	6,301,317	4,763,049	278,759
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	63,322	175	378,924	442,082	126,480
5	IPUC Order # 28661					
6						
7	Unfunded Accum Def Income Tax (254966)	50,814,726	Various	378,735	694,614	51,130,605
8						
9	Idaho DSM Rider (254201)	(782,231)	Various	37,911,476	45,247,781	6,554,074
10	Order #29026					
11						
12	Oregon Solar Pilot - (254005)	2,400,864	Various	554,880	1,194,533	3,040,517
13	Order #10-198					
14						
15	Green Tags Oregon (254415)	132,831	1823, 254	137,928	78,074	72,977
16	Order #11-086					
17						
18	Regulatory Unfunded Accum Def Income Tax (254419)	4,675,677	1823	5,341,917	666,240	
19						
20	Revenue Sharing (254101)	7,999,145	1823, 400	11,026,832	6,187,165	3,159,478
21	IPUC Order #33149					
22						
23	BPA Credit Residential Idaho (254401)	643,903	142	2,481,690	3,862,855	2,025,068
24	Advice # 11-03 (ID) #11-15 (OR)					
25						
26	WAQC Carryover (254901)	112,536	401	112,536	48,688	48,688
27	IPUC Order #29505					
28						
29	Bridger Depreciation #12-296 -(254800)	809,830			321,839	1,131,669
30						
31	Oregon DSM Rider - (254202)	(3,907,536)			3,907,536	
32	Advice #05-03					
33						
34	Minor Items (7)	63,175	Various	593,846	674,011	143,340
35						
36						
37						
38						
39						
40						
41	TOTAL	64,843,269		65,220,081	68,088,467	67,711,655

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	04/15/2016	End of 2015/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	512,068,335	500,194,726
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	466,541,569	453,982,593
5	Large (or Ind.) (See Instr. 4)	182,254,287	182,675,224
6	(444) Public Street and Highway Lighting	4,039,381	4,133,623
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,164,903,572	1,140,986,166
11	(447) Sales for Resale	30,887,261	77,164,887
12	TOTAL Sales of Electricity	1,195,790,833	1,218,151,053
13	(Less) (449.1) Provision for Rate Refunds	13,865,518	18,348,408
14	TOTAL Revenues Net of Prov. for Refunds	1,181,925,315	1,199,802,645
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,119,479	3,780,239
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	24,852,979	23,695,291
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	31,174,302	27,734,886
22	(456.1) Revenues from Transmission of Electricity of Others	24,129,372	22,627,916
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	84,276,132	77,838,332
27	TOTAL Electric Operating Revenues	1,266,201,447	1,277,640,977

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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
4,977,176	4,965,076	432,275	425,036	2
				3
6,059,428	5,877,580	85,560	84,425	4
3,195,786	3,217,070	119	116	5
32,103	32,641	2,592	2,380	6
				7
				8
				9
14,264,493	14,092,367	520,546	511,957	10
1,254,136	2,220,419			11
15,518,629	16,312,786	520,546	511,957	12
				13
15,518,629	16,312,786	520,546	511,957	14

Line 12, column (b) includes $ 7,691,485 of unbilled revenues.
Line 12, column (d) includes 97,949 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)	$	3,991,239
Misc. Under $250,000		128,240
Total Account 451	$	4,119,479

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

This amount consists of:

Alternate Distribution Service	$	321,995
DSM Activity		30,531,891
Misc. Under $250,000		320,416
Total Account 456	$	31,174,302

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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	04/15/2016	End of 2015/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	4,909,951	485,187,406	430,891	11,395	0.0988
3	03 - Residential Master Meter	3,915	369,431	22	177,955	0.0944
4	05 - Residential - TOD	22,760	2,173,445	1,362	16,711	0.0955
5	15 - Dusk to dawn lighting	2,643	647,369			0.2449
6	Unbilled Revenues	37,907	3,804,720			0.1004
7	Other Revenues		19,885,964			
8	Total 440	4,977,176	512,068,335	432,275	11,514	0.1029
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	148,554	18,030,960	30,568	4,860	0.1214
12	09P - General service	468,026	30,263,440	210	2,228,695	0.0647
13	09S - General service	3,310,465	242,228,577	33,750	98,088	0.0732
14	09T - General service	5,919	427,302	4	1,479,750	0.0722
15	15 - Dusk to Dawn Light	4,161	740,435			0.1779
16	19P - Uniform rate contracts	2,219,894	128,442,280	112	19,820,482	0.0579
17	19S - Uniform rate contracts	6,409	407,625	1	6,409,000	0.0636
18	19T - Uniform rate contracts	133,079	7,770,633	3	44,359,667	0.0584
19	24S - Irrigation Pumping	2,046,290	162,170,953	20,151	101,548	0.0793
20	40 - General service	10,300	887,261	877	11,745	0.0861
21	Special Contracts	842,100	43,182,373	3	280,700,000	0.0513
22	Commercial & Industrial Unbill	60,017	3,882,851			0.0647
23	Other Revenues		10,361,166			
24	Total 442	9,255,214	648,795,856	85,679	108,022	0.0701
25						
26	444 - Public Street Lighting:					
27	40 - General service	1,120	96,700	456	2,456	0.0863
28	41 - Street lighting	28,127	3,696,413	1,607	17,503	0.1314
29	42 - Traffic control lighting	2,832	178,272	529	5,353	0.0629
30	Unbilled	24	3,915			0.1631
31	Other Revenues		64,081			
32	Total 444	32,103	4,039,381	2,592	12,385	0.1258
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,166,544	1,157,212,087	520,546	27,215	0.0817
42	Total Unbilled Rev.(See Instr. 6)	97,949	7,691,485	0	0	0.0785
43	TOTAL	14,264,493	1,164,903,572	520,546	27,403	0.0817

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	04/15/2016	End of 2015/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)	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	Avista Corp.	SF	WSPP	n/a	n/a	n/a
4	Basin Electric Power Cooperative	SF	WSPP	n/a	n/a	n/a
5	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
6	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
7	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
8	BP Energy Company	SF	WSPP	n/a	n/a	n/a
9	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
10	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
11	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
12	Cargill Power Markets LLC	OS	ISDA	n/a	n/a	n/a
13	City of Anaheim	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**

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.
			-861,190	-861,190	1
4,400		64,000		64,000	2
72,813		1,230,085		1,230,085	3
2,118		54,030		54,030	4
845		16,805		16,805	5
150			1,200	1,200	6
32,888		653,025		653,025	7
2,400		62,464		62,464	8
300		4,500		4,500	9
1,810		38,245		38,245	10
2,353			17,690	17,690	11
			1,128,634	1,128,634	12
37,200		919,472		919,472	13
160		3,134		3,134	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	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	Grant County Public Utility District #2	SF	WSPP	n/a	n/a	n/a
6	Iberdrola Renewables, Inc.	SF	WSPP	n/a	n/a	n/a
7	Iberdrola Renewables, Inc.	OS	-	n/a	n/a	n/a
8	Iberdrola Renewables, Inc.	OS	WSPP	n/a	n/a	n/a
9	Jeffries Bache	OS	-	n/a	n/a	n/a
10	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
11	Macquarie Energy LLC	OS	ISDA	n/a	n/a	n/a
12	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
13	Morgan Stanley Capital Group Inc.	SF	ISDA	n/a	n/a	n/a
14	Morgan Stanley Capital Group Inc.	OS	ISDA	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.
51,000		1,438,760		1,438,760	1
10		220		220	2
3,437		73,384		73,384	3
153,345		3,412,586		3,412,586	4
2,163		50,606		50,606	5
13,600		305,566		305,566	6
			17,113	17,113	7
			16,472	16,472	8
			2,361,474	2,361,474	9
148,400		4,362,200		4,362,200	10
			215,438	215,438	11
			272	272	12
43,627		833,497		833,497	13
401			5,359	5,359	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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 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	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
2	Nevada Power Company, dba NVEnergy	SF	WSPP	n/a	n/a	n/a
3	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
4	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
5	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
6	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
7	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
8	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
9	PacifiCorp Inc.	OS	T-7	n/a	n/a	n/a
10	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
11	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
12	Portland General Electric Company	OS	T-7	n/a	n/a	n/a
13	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
14	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
	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) 04/15/2016	Year/Period of Report End of 2015/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.
			574,949	574,949	1
18,161		299,299		299,299	2
14,846			191,688	191,688	3
			10,766	10,766	4
3,428		68,022		68,022	5
3,375			27,490	27,490	6
9,544		173,862		173,862	7
400			5,600	5,600	8
87			1,805	1,805	9
57,704		1,311,422		1,311,422	10
1,672			26,420	26,420	11
4			72	72	12
			20,130	20,130	13
9,610		119,981		119,981	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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 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.	OS	WSPP	n/a	n/a	n/a
2	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
3	Puget Sound Energy, Inc.	OS	T-7	n/a	n/a	n/a
4	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
5	Seattle City Light	SF	WSPP	n/a	n/a	n/a
6	Seattle City Light	OS	WSPP	n/a	n/a	n/a
7	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
8	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
9	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
10	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
11	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
12	Talen Energy Marketing, LLC	SF	WSPP	n/a	n/a	n/a
13	Talen Energy Marketing, LLC	OS	WSPP	n/a	n/a	n/a
14	Talen Energy Marketing, LLC	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	04/15/2016	End of 2015/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.
10,358			29,345	29,345	1
14,746		303,898		303,898	2
22			394	394	3
4,200		69,800		69,800	4
11,628		274,040		274,040	5
425			2,825	2,825	6
301,897		6,048,170		6,048,170	7
25			150	150	8
			476,119	476,119	9
58			1,145	1,145	10
1,081		33,752		33,752	11
1,863		31,603		31,603	12
			7,232	7,232	13
350			1,950	1,950	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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 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	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
2	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
3	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
4	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
5	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
6	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
8	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
9	Prior Year Adjustments	AD	-	n/a	n/a	n/a
10	Transmission Penalty Distribution	AD	-	n/a	n/a	n/a
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) 04/15/2016	Year/Period of Report End of 2015/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.
7,511		178,846		178,846	1
50			400	400	2
			1,769	1,769	3
173,226		3,261,545		3,261,545	4
75			1,625	1,625	5
			23,133	23,133	6
34,376		819,694		819,694	7
			38,535	38,535	8
-6			194	194	9
			24,550	24,550	10
					11
					12
					13
					14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Schedule Page: 310 Line No.: 1 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

Schedule Page: 310 Line No.: 6 Column: b
Non-firm Sales

Schedule Page: 310 Line No.: 11 Column: b
Non-firm Sales

Schedule Page: 310 Line No.: 12 Column: b
ISDA Master Agreement with Cargill Power Markets, LLC dated June 13, 2011

Schedule Page: 310.1 Line No.: 7 Column: b
Iberdrola Renewables, Inc, Capacity Agreement, dated January 16, 2015

Schedule Page: 310.1 Line No.: 8 Column: b
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 9 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4,2008

Schedule Page: 310.1 Line No.: 11 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

Schedule Page: 310.1 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 14 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 3 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 4 Column: b
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 6 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 8 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 9 Column: b
Spinning or Operating Reserves

Schedule Page: 310.2 Line No.: 11 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 12 Column: b
Spinning or Operating Reserves

Schedule Page: 310.2 Line No.: 13 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 1 Column: b
Non-firm Sales

Schedule Page: 310.3 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 310.3 Line No.: 6 Column: b
Non-firm Sales

Schedule Page: 310.3 Line No.: 8 Column: b
Non-firm Sales

Schedule Page: 310.3 Line No.: 9 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 310.3 Line No.: 13 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 14 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 2 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 3 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 5 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 6 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 8 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 9 Column: b

Prior Year Adjustments

Schedule Page: 310.4 Line No.: 10 Column: b

Transmission Penalty Distribution

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	04/15/2016	End of 2015/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	1,287,887	1,376,709
5	(501) Fuel	131,286,356	156,172,175
6	(502) Steam Expenses	9,791,612	8,741,266
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,262,175	1,599,507
10	(506) Miscellaneous Steam Power Expenses	6,676,269	9,598,723
11	(507) Rents	432,038	530,520
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	150,736,337	178,018,900
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	126,993	277,886
16	(511) Maintenance of Structures	878,071	708,308
17	(512) Maintenance of Boiler Plant	13,861,559	10,923,064
18	(513) Maintenance of Electric Plant	5,412,553	6,044,954
19	(514) Maintenance of Miscellaneous Steam Plant	6,923,251	5,806,415
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	27,202,427	23,760,627
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	177,938,764	201,779,527
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	5,798,402	5,700,460
45	(536) Water for Power	9,070,347	7,316,134
46	(537) Hydraulic Expenses	14,907,949	14,097,825
47	(538) Electric Expenses	1,623,508	1,530,453
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,675,338	5,732,591
49	(540) Rents	235,266	259,705
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	37,310,810	34,637,168
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	120,335	122,182
54	(542) Maintenance of Structures	1,120,484	1,387,369
55	(543) Maintenance of Reservoirs, Dams, and Waterways	575,444	366,307
56	(544) Maintenance of Electric Plant	2,655,929	2,279,584
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,860,095	2,554,638
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,332,287	6,710,080
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	44,643,097	41,347,248

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	04/15/2016	End of 2015/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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	646,633	813,875
63	(547) Fuel	54,944,643	45,068,831
64	(548) Generation Expenses	4,603,907	3,596,219
65	(549) Miscellaneous Other Power Generation Expenses	934,376	905,574
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	61,129,559	50,384,499
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	363,695	378,067
71	(553) Maintenance of Generating and Electric Plant	71,909	86,516
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,270,216	1,391,428
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,705,820	1,856,011
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	62,835,379	52,240,510
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	217,596,604	237,121,899
77	(556) System Control and Load Dispatching	2,436	-1,242
78	(557) Other Expenses	20,615,245	25,139,587
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	238,214,285	262,260,244
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	523,631,525	557,627,529
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,136,382	4,019,284
84			
85	(561.1) Load Dispatch-Reliability		55,425
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,757,323	1,673,701
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,159,643	926,555
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	21,585	38,422
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,633,328	2,458,270
94	(563) Overhead Lines Expenses	967,338	669,240
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,279,133	6,081,299
97	(566) Miscellaneous Transmission Expenses	2,365	18,274
98	(567) Rents	3,084,849	3,284,850
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,041,946	19,225,320
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	157,051	169,505
102	(569) Maintenance of Structures	12,690	26,645
103	(569.1) Maintenance of Computer Hardware	23,408	9,454
104	(569.2) Maintenance of Computer Software	867,398	960,142
105	(569.3) Maintenance of Communication Equipment	29,123	42,031
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,286,329	3,702,550
108	(571) Maintenance of Overhead Lines	2,935,312	3,198,420
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		1,593
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,311,311	8,110,340
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,353,257	27,335,660

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	04/15/2016	End of 2015/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	4,289,300	4,028,859
135	(581) Load Dispatching	3,897,253	3,643,133
136	(582) Station Expenses	1,339,544	1,180,321
137	(583) Overhead Line Expenses	3,968,009	3,138,798
138	(584) Underground Line Expenses	2,889,346	2,525,008
139	(585) Street Lighting and Signal System Expenses	87,956	76,902
140	(586) Meter Expenses	4,769,220	4,424,696
141	(587) Customer Installations Expenses	784,157	694,859
142	(588) Miscellaneous Expenses	6,041,032	5,788,865
143	(589) Rents	262,071	466,127
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,327,888	25,967,568
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	10,627	16,451
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,630,618	3,950,824
149	(593) Maintenance of Overhead Lines	14,203,471	13,906,165
150	(594) Maintenance of Underground Lines	604,456	630,375
151	(595) Maintenance of Line Transformers	36,603	148,125
152	(596) Maintenance of Street Lighting and Signal Systems	486,847	531,740
153	(597) Maintenance of Meters	767,987	735,448
154	(598) Maintenance of Miscellaneous Distribution Plant	289,620	418,635
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,030,229	20,337,763
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	48,358,117	46,305,331
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	484,451	503,846
160	(902) Meter Reading Expenses	1,843,348	1,698,642
161	(903) Customer Records and Collection Expenses	15,508,388	16,630,398
162	(904) Uncollectible Accounts	3,319,967	6,715,796
163	(905) Miscellaneous Customer Accounts Expenses	395	95
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	21,156,549	25,548,777

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	04/15/2016	End of 2015/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	807,713	593,673
168	(908) Customer Assistance Expenses	37,606,989	34,149,782
169	(909) Informational and Instructional Expenses	424,680	374,524
170	(910) Miscellaneous Customer Service and Informational Expenses	735,552	696,365
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	39,574,934	35,814,344
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	79,720	
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	79,720	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	73,062,858	73,163,837
182	(921) Office Supplies and Expenses	14,719,911	17,437,094
183	(Less) (922) Administrative Expenses Transferred-Credit	26,120,468	27,257,584
184	(923) Outside Services Employed	8,177,858	4,705,146
185	(924) Property Insurance	3,382,607	3,461,411
186	(925) Injuries and Damages	6,644,800	6,125,055
187	(926) Employee Pensions and Benefits	45,004,540	61,971,169
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,616,257	3,457,838
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	618,107	453,160
192	(930.2) Miscellaneous General Expenses	5,444,853	4,907,415
193	(931) Rents	2,000	176
194	TOTAL Operation (Enter Total of lines 181 thru 193)	134,553,323	148,424,717
195	Maintenance		
196	(935) Maintenance of General Plant	5,817,078	7,508,482
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	140,370,401	155,933,199
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	800,524,503	848,564,840

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	04/15/2016	End of 2015/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	[illegible]	[illegible]
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					

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	04/15/2016	End of 2015/Q4

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)	
25,577				2,160,857		2,160,857	1
1,401			155,672	57,887		213,559	2
278				10,695		10,695	3
8,705				434,633		434,633	4
35,670				2,210,264		2,210,264	5
10,600				790,198		790,198	6
8,739				545,582		545,582	7
							8
257				18,420		18,420	9
951				69,799		69,799	10
832				62,070		62,070	11
42				1,094		1,094	12
3,972				184,552		184,552	13
688				49,396		49,396	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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	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 Gulch Wind Park	LU		N/A	N/A	N/A
6	Cassia Wind Farm	LU	-	N/A	N/A	N/A
7	City of Cove, Oregon / Mill Creek	LU	-	N/A	N/A	N/A
8	City of Hailey	LU	-	N/A	N/A	N/A
9	City of Pocatello	LU	-	N/A	N/A	N/A
10	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
11	Clifton E. Jenson/Birch Creek	LU	-	.05 Mw		
12	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
13	Consolidated Hydro Inc. / Enel		-			
14	Barber 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.
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)	
51,243				2,888,444		2,888,444	1
27,344				1,463,915		1,463,915	2
52,909				4,403,823		4,403,823	3
8,474				732,581		732,581	4
							5
20,563				978,061		978,061	6
3,479				244,601		244,601	7
15				1,076		1,076	8
1,133				84,473		84,473	9
3,420				332,895		332,895	10
340			17,500	14,062		31,562	11
44,366				3,049,703		3,049,703	12
							13
9,370				485,620		485,620	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	Dietrich Drop	LU	-	N/A	N/A	N/A
2	GeoBon #2	LU	-	N/A	N/A	N/A
3	Lowline #2	LU	-	N/A	N/A	N/A
4	Rock Creek #2	LU	-	N/A	N/A	N/A
5	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
6	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
7	Curry Cattle Company	LU	-	.084Mw		
8	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
9	David R Snedigar	LU	-	N/A	N/A	N/A
10	Desert Meadow Wind Farm	LU	-	N/A	N/A	N/A
11	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
12	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
13	Fisheries Development	OS	-	N/A	N/A	N/A
14	Fossil Gulch 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.
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)	
14,262				802,944		802,944	1
3,031				228,100		228,100	2
10,091				537,227		537,227	3
6,250				328,832		328,832	4
4,766				337,984		337,984	5
9,621				659,848		659,848	6
744			26,796	30,741		57,537	7
482				8,074		8,074	8
1,386				97,333		97,333	9
51,329				3,531,906		3,531,906	10
1,378				75,765		75,765	11
3,540				274,398		274,398	12
1,205				19,937		19,937	13
21,790				1,245,178		1,245,178	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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.

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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	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
2	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
3	Hammett Hill Windfarm, LLC	LU	-	N/A	N/A	N/A
4	Hazelton B Power Company	LU	-	N/A	N/A	N/A
5	Head of U Canal	LU		N/A	N/A	N/A
6	High Mesa Energy	LU	-	N/A	N/A	N/A
7	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
8	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
9	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
10	Hot Springs Wind Farm	LU	--	N/A	N/A	N/A
11	Idaho Winds / Sawtooth Wind Project	LU	-	N/A	N/A	N/A
12	J R Simplot Co.	LU	-	N/A	N/A	N/A
13	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
14	James B. Howell / CHI Elk Creek	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)	
21,162				1,347,228		1,347,228	1
28,758				1,625,860		1,625,860	2
50,491				3,479,377		3,479,377	3
23,244				1,651,824		1,651,824	4
3,449				273,969		273,969	5
80,916				3,911,669		3,911,669	6
1,605				137,200		137,200	7
42,403				3,015,688		3,015,688	8
15,404				881,159		881,159	9
33,111				2,041,072		2,041,072	10
49,976				3,952,392		3,952,392	11
80,768				4,288,263		4,288,263	12
1,244				93,768		93,768	13
4,181				265,983		265,983	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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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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.

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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	John R LeMoyne	LU	--	N/A	N/A	N/A
2	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
3	Kootenai Electric Cooperative / Fighti	LU	-	N/A	N/A	N/A
4	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
5	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
6	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
7	Lime Wind	LU	-	N/A	N/A	N/A
8	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
9	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
10	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
11	Mainline Windfarm	LU	-	N/A	N/A	N/A
12	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
13	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
14	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
	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	04/15/2016	End of 2015/Q4

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)	
644				35,836		35,836	1
3,429				307,307		307,307	2
11,750				960,262		960,262	3
2,494				235,927		235,927	4
5,927				383,764		383,764	5
1,188				88,578		88,578	6
6,089				448,194		448,194	7
5,460				358,462		358,462	8
2,298				166,850		166,850	9
5,570				279,222		279,222	10
48,257				3,328,970		3,328,970	11
3,021				211,453		211,453	12
40,347				2,564,160		2,564,160	13
47,105				2,640,493		2,640,493	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
2	New Energy One / Rock Creek Dairy	LU	-	N/A	N/A	N/A
3	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
4	Owyhee Irrigation District					
5	Mitchell Butte	LU	-	N/A	N/A	N/A
6	Owyhee Dam	LU		N/A	N/A	N/A
7	Tunnel #1	LU	-	N/A	N/A	N/A
8	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
9	Pigeon Cove Power	LU	-	1.389Mw	[illegible]	[illegible]
10	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
11	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
12	Pristine Springs Inc. #3	LU	-	N/A	N/A	N/A
13	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
14	Richard Kaster					
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
495				34,652		34,652	1
9,546				410,768		410,768	2
30,428				1,701,015		1,701,015	3
							4
1,076				33,412		33,412	5
8,507				215,727		215,727	6
							7
51,718				4,335,833		4,335,833	8
8,982			486,150	322,895		809,045	9
28,014				1,577,456		1,577,456	10
766				46,694		46,694	11
1,289				75,188		75,188	12
1,394				104,822		104,822	13
							14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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	Box Canyon	LU	-	N/A	N/A	N/A
2	Briggs Creek	LU	-	N/A	N/A	N/A
3	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
4	Riverside Investments					
5	Arena Drop	LU	-	N/A	N/A	N/A
6	Fargo Drop	LU	-	N/A	N/A	N/A
7	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
8	Rockland Wind Project	LU	-	N/A	N/A	N/A
9	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
10	Ryegrass Windfarm	LU	-	N/A	N/A	N/A
11	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
12	SE Hazelton A LP	LU	-	N/A	N/A	N/A
13	Shorock Hydro Inc.					
14	Shoshone CSPP	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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)	
1,983				131,593		131,593	1
3,589				244,916		244,916	2
4,652				247,321		247,321	3
							4
1,501				113,516		113,516	5
3,498				194,410		194,410	6
10,617			552,508	438,780		991,288	7
218,662				13,836,699		13,836,699	8
76,677				5,138,703		5,138,703	9
46,727				3,212,867		3,212,867	10
53,270				2,990,578		2,990,578	11
23,982				1,653,087		1,653,087	12
							13
1,258				116,018		116,018	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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.

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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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	Shoshone #2	LU	-	N/A	N/A	N/A
2	Snake River Pottery	LU	-	N/A	N/A	N/A
3	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
4	Tamarack Energy Partnership	LU	-	4.942Mw		
5	Tasco - Nampa	OS	-	N/A	N/A	N/A
6	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
7	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
8	Thousand Springs Wind Park	LU	-	N/A	N/A	N/A
9	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
10	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
11	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
12	Two Ponds Windfarm	LU	-	N/A	N/A	N/A
13	White Water Ranch	LU	-	N/A	N/A	N/A
14	William Arkoosh/Littlewood	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)	
2,308				163,659		163,659	1
349				23,856		23,856	2
27,677				2,002,990		2,002,990	3
29,409			1,576,498	1,389,851		2,966,349	4
483				10,412		10,412	5
8							6
29,844				1,674,260		1,674,260	7
26,491				1,485,785		1,485,785	8
23,774				1,330,238		1,330,238	9
62,944				4,183,746		4,183,746	10
8,456				515,850		515,850	11
51,309				3,507,588		3,507,588	12
587				40,536		40,536	13
3,071				233,393		233,393	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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	Littlewood River Ranch II	LU		N/A	N/A	N/A
2	Willis and Betty Deveny/Shingle Creek	LU	-	N/A	N/A	N/A
3	Wilson Power Company	LU	-	N/A	N/A	N/A
4	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
5	Prior Period Overpayment Recovery		-			
6	Scheduling Deviation		-			
7	Other Purchased Power					
8	ADM Investor Services Inc	OS		N/A	N/A	N/A
9	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
10	Avista Corp.	OS	T-12	N/A	N/A	N/A
11	Avista Corp.	SF	WSPP	N/A	N/A	N/A
12	Avista Corp.	OS	WSPP	N/A	N/A	N/A
13	Basin Electric Power Cooperative	SF	WSPP	N/A	N/A	N/A
14	Black Hills Power Inc.	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)	
74				1,167		1,167	1
805				62,025		62,025	2
27,057				1,920,418		1,920,418	3
52,415				4,382,894		4,382,894	4
				-8,976		-8,976	5
2,190							6
							7
					-1,064,614	-1,064,614	8
34,096				1,047,016		1,047,016	9
21					537	537	10
75,515				1,952,680		1,952,680	11
					215,447	215,447	12
149				11,513		11,513	13
20				1,100		1,100	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
2	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
3	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
4	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
5	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
6	Cargill Power Markets LLC	OS	ISDA	N/A	N/A	N/A
7	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
8	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
9	Citigroup Energy Inc.	OS	ISDA	N/A	N/A	N/A
10	City of Anaheim	SF	WSPP	N/A	N/A	N/A
11	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
12	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
13	EDF Trading North America, LLC	OS	WSPP	N/A	N/A	N/A
14	Energy Keepers	SF	WSPP	N/A	N/A	N/A
	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	04/15/2016	End of 2015/Q4

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)	
					297,481	297,481	1
135					3,512	3,512	2
103,286				2,926,124		2,926,124	3
12,898				485,020		485,020	4
18,450				441,070		441,070	5
					540,762	540,762	6
5,200				137,652		137,652	7
5					127	127	8
					151,944	151,944	9
76				2,006		2,006	10
833				9,100		9,100	11
60,385				2,250,545		2,250,545	12
10,495					697,010	697,010	13
650				11,936		11,936	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
2	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
3	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
4	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
5	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
6	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
7	Jefferies Bache	OS	-	N/A	N/A	N/A
8	Macquarie Energy LLC	OS	ISDA	N/A	N/A	N/A
9	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
10	Nevada Power Company, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
11	Nevada Power Company, DBA NV Energy	OS	WSPP	N/A	N/A	N/A
12	Nobles Americas Energy Solutions LLC	SF	WSPP	N/A	N/A	N/A
13	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
14	NorthWestern Energy	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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,075				49,842		49,842	1
15,625				392,480		392,480	2
10					273	273	3
20,475				617,147		617,147	4
64,883				1,581,907		1,581,907	5
30,800				1,101,100		1,101,100	6
					-14,108	-14,108	7
					-286,198	-286,198	8
113,679				3,197,264		3,197,264	9
21,949				898,271		898,271	10
					6,703	6,703	11
6,400				218,208		218,208	12
21					532	532	13
5,427				102,523		102,523	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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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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	PacifiCorp Inc.	OS	T-13	N/A	N/A	N/A
2	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
3	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
4	Portland General Electric Company	OS	T-14	N/A	N/A	N/A
5	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
6	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
7	Puget Sound Energy, Inc.	OS	T-9	N/A	N/A	N/A
8	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
9	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
10	Salt River Project	SF	WSPP	N/A	N/A	N/A
11	Seattle City Light	OS	WSPP	N/A	N/A	N/A
12	Seattle City Light	SF	WSPP	N/A	N/A	N/A
13	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Co., dba NV Energ	OS	T-55	N/A	N/A	N/A
	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	04/15/2016	End of 2015/Q4

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: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
99					2,575	2,575	1
690				16,900		16,900	2
					212,313	212,313	3
31					826	826	4
23,016				759,724		759,724	5
120,289				5,078,264		5,078,264	6
36					949	949	7
28,130				681,348		681,348	8
400				10,112		10,112	9
124,717				2,811,045		2,811,045	10
14					357	357	11
13,189				360,555		360,555	12
87,416				2,937,085		2,937,085	13
58					1,537	1,537	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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 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	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
2	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
3	Tacoma Power	OS	WSPP	N/A	N/A	N/A
4	Tacoma Power	SF	WSPP	N/A	N/A	N/A
5	Talen Energy	SF	WSPP	N/A	N/A	N/A
6	Talen Energy	OS	WSPP	N/A	N/A	N/A
7	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
8	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
9	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
10	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
11	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
12	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
13	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
14	Oregon Solar Customers	OS	-	N/A	N/A	N/A
	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	04/15/2016	End of 2015/Q4

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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					311	311	1
1,125				21,830		21,830	2
3					75	75	3
4,050				152,250		152,250	4
82,444				2,818,569		2,818,569	5
5,517					210,309	210,309	6
2,787				81,251		81,251	7
19,144				466,924		466,924	8
50,951				1,786,158		1,786,158	9
1,680				33,412		33,412	10
75,595				4,868,360		4,868,360	11
293,122				16,786,786		16,786,786	12
176,868				18,806,764		18,806,764	13
820					24,261	24,261	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

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	04/15/2016	End of 2015/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	Prior Year Adjustments	AD	-	N/A	N/A	N/A
2	Power Exchanges		-			
3	Avista Corp	EX		N/A	N/A	N/A
4	Bonneville Power Administration	EX	-	N/A	N/A	N/A
5	NorthWestern Energy	EX	-	N/A	N/A	N/A
6	PacifiCorp Inc.	EX	-	N/A	N/A	N/A
7	Sierra Pacific Power Co., dba NV Energ	EX	-	N/A	N/A	N/A
8	Clatskanie PUD	EX	153	N/A	N/A	N/A
9	Other Transactions					
10	Acctg Valuation of Clatskanie PUD	OS				
11	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
12	PacifiCorp Loss Repayment	OS	-	N/A	N/A	N/A
13	Black Thunder Test Burn	OS		N/A	N/A	N/A
14						
	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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
-6					237	237	1
							2
	359						3
	66,231						4
		448					5
	144,521	97,125					6
		1,691					7
	65,399	62,975					8
							9
					114,584	114,584	10
					6,701,263	6,701,263	11
64,775							12
					2,526,094	2,526,094	13
							14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Schedule Page: 326 Line No.: 2 Column: e
Unavailable

Schedule Page: 326 Line No.: 2 Column: f
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Schedule Page: 326.1 Line No.: 11 Column: e
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Schedule Page: 326.1 Line No.: 11 Column: f
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Schedule Page: 326.2 Line No.: 7 Column: e
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Schedule Page: 326.2 Line No.: 7 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 13 Column: b
Non-Firm Purchases

Schedule Page: 326.3 Line No.: 4 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 13 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.5 Line No.: 9 Column: e
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Schedule Page: 326.5 Line No.: 9 Column: f
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Schedule Page: 326.6 Line No.: 7 Column: e
Unavailable

Schedule Page: 326.6 Line No.: 7 Column: f
Unavailable

Schedule Page: 326.7 Line No.: 3 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.7 Line No.: 4 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Co. The actual demand is not used in determining the cost of energy.

Schedule Page: 326.7 Line No.: 4 Column: e
Unavailable

Schedule Page: 326.7 Line No.: 4 Column: f
Unavailable

Schedule Page: 326.7 Line No.: 5 Column: b
Non-Firm Purchases

Schedule Page: 326.7 Line No.: 6 Column: b
Non-Firm Purchases

Schedule Page: 326.8 Line No.: 3 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.8 Line No.: 6 Column: a
Difference between booked and scheduled energy.

Schedule Page: 326.8 Line No.: 8 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

Schedule Page: 326.8 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 326.8 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 2 Column: b
Spinning or Operating Reserves

Schedule Page: 326.9 Line No.: 6 Column: b
ISDA Master Agreement With Cargill Power Markets, LLC, dated June 13, 2011

Schedule Page: 326.9 Line No.: 8 Column: b
Spinning or Operating Reserves

Schedule Page: 326.9 Line No.: 9 Column: b
ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011

Schedule Page: 326.9 Line No.: 13 Column: b
Unit Contingent Purchases

Schedule Page: 326.10 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 7 Column: b
Prudential Bache Commodities, LLC (Jefferies Bache) Futures Account Document, dated September 4, 2008 and contract ended on May 19, 2015.

Schedule Page: 326.10 Line No.: 8 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

Schedule Page: 326.10 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 326.10 Line No.: 13 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 1 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 326.11 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 7 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 11 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 14 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 326.12 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 6 Column: b
Unit Contingent Purchases

Schedule Page: 326.12 Line No.: 14 Column: b
Schedule 88 Oregon Solar

Schedule Page: 326.13 Line No.: 1 Column: b
Out of period adjustments

Schedule Page: 326.13 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 4 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 5 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 8 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam.

Schedule Page: 326.13 Line No.: 10 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam.

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FOOTNOTE DATA

Schedule Page: 326.13 Line No.: 11 Column: b

Incentive program for customers to reduce demand during peak hours

Schedule Page: 326.13 Line No.: 12 Column: b

Repayment of transmisssion losses

Schedule Page: 326.13 Line No.: 13 Column: b

Coal supply test burn at Jim Bridger Plant

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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 - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
4	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	AD
5	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
6	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	AD
7	PacifiCorp - Imnaha	PacifiCorp West	PacifiCorp West	FNO
8	PacifiCorp - Imnaha	PacifiCorp West	PacifiCorp West	AD
9	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
10	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
11	Shell Energy North America (US), L.P.	Seattle City Light	Bonneville Power Administration	OS
12	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	OS
13	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
14	United Materials of Great Falls	PacifiCorp East	Sierra Pacific Power	OS
15	United Materials of Great Falls			AD
16				
17	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	LFP
18	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	LFP
19	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
20	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	LFP
21	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
22	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	LFP
23				
24	Black Hills Power			NF
25	Bonneville Power Adminstration	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
26	Bonneville Power Adminstration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
27	Bonneville Power Adminstration	Bonneville Power Administration	Bonneville Power Administration	NF
28	Bonneville Power Adminstration	Bonneville Power Administration	Sierra Pacific Power	NF
29	Bonneville Power Adminstration	Avista	Bonneville Power Administration	NF
30	Bonneville Power Adminstration	Avista	Sierra Pacific Power	NF
31	Bonneville Power Administration			AD
32	Cargill-Alliant			AD
33	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34				
	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	04/15/2016	End of 2015/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				336,735	336,735	1
9						2
9				297,100	297,100	3
9						4
9				1,260,469	1,260,469	5
9						6
9				2,067	2,067	7
9						8
Legacy	Minidoka, Idaho	Various in Idaho		9,393	9,393	9
Legacy	LaGrande, Oregon	Various in Idaho		16,261	16,261	10
4				277,687	277,687	11
5/6				6	6	12
5/6				7,539	7,539	13
5/6				7,859	7,859	14
5/6						15
						16
7/8	BORA	KPRT		663,949	663,949	17
7/8	BORA	LAGRANDE		69,227	69,227	18
7/8	BORA	HURR		287,668	287,668	19
7/8	JBWT	HMWY		470,041	470,041	20
7/8	KPRT	HURR		121,062	121,062	21
7/8	LYPK	LAGRANDE		21,675	21,675	22
						23
7/8						24
7/8	BPAT.NWMT	LAGRANDE		1,369	1,369	25
7/8	BPAT.NWMT	M345		266	266	26
7/8	LAGRANDE	LAGRANDE		776	776	27
7/8	LAGRANDE	M345		10,813	10,813	28
7/8	LOLO	LAGRANDE		3,193	3,193	29
7/8	LOLO	M345		1,956	1,956	30
7/8						31
7/8						32
7/8	BPAT.NWMT	BRDY		40	40	33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
2	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
3	Iberdrola Renewables LLC	PacifiCorp East	Bonneville Power Administration	NF
4	Iberdrola Renewables LLC	Idaho Power Company	PacifiCorp East	NF
5	Iberdrola Renewables LLC	Idaho Power Company	Sierra Pacific Power	NF
6	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
7	Iberdrola Renewables LLC	Bonneville Power Administration	PacifiCorp East	NF
8	Iberdrola Renewables LLC	Bonneville Power Administration	Sierra Pacific Power	NF
9	Iberdrola Renewables LLC	Avista	PacifiCorp East	NF
10	Iberdrola Renewables LLC	Avista	Sierra Pacific Power	NF
11	Iberdrola Renewables LLC	Sierra Pacific Power	Bonneville Power Administration	NF
12	Iberdrola Renewables LLC	PacifiCorp West	PacifiCorp East	NF
13	Iberdrola Renewables LLC			AD
14	MacQuarie Cook	Bonneville Power Administration	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	Idaho Power Company	NF
17	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
22	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
27	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp West	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp East	Avista	NF
33	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
34				
	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	04/15/2016	End of 2015/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)	MegaWatt Hours Delivered (j)	Line No.
7/8	BPAT.NWMT	M345		115	115	1
7/8	BRDY	M345		40	40	2
7/8	GSHN	LAGRANDE		62	62	3
7/8	HMWY	BORA		3,286	3,286	4
7/8	HMWY	M345		635	635	5
7/8	JBSN	M345		140	140	6
7/8	LAGRANDE	BORA		1,669	1,669	7
7/8	LAGRANDE	M345		9,565	9,565	8
7/8	LOLO	BORA		40	40	9
7/8	LOLO	M345		1,762	1,762	10
7/8	M345	LAGRANDE		1,214	1,214	11
7/8	SMLK	BORA		250	250	12
7/8						13
7/8	LAGRANDE	M345		379	379	14
7/8	AVAT.NWMT	BORA		309	309	15
7/8	AVAT.NWMT	HMWY		25	25	16
7/8	AVAT.NWMT	LAGRANDE		856	856	17
7/8	AVAT.NWMT	M345		47,673	47,673	18
7/8	AVAT.NWMT	M345		29,450	29,450	19
7/8	BORA	LAGRANDE		410	410	20
7/8	BORA	M345		3,187	3,187	21
7/8	BPAT.NWMT	BORA		1,350	1,350	22
7/8	BPAT.NWMT	BRDY		612	612	23
7/8	BPAT.NWMT	LAGRANDE		6,720	6,720	24
7/8	BPAT.NWMT	M345		6,527	6,527	25
7/8	BPAT.NWMT	M345		5,382	5,382	26
7/8	BRDY	AVAT.NWMT		19	19	27
7/8	BRDY	BORA		540	540	28
7/8	BRDY	HMWY		607	607	29
7/8	BRDY	HURR		10	10	30
7/8	BRDY	LAGRANDE		10,379	10,379	31
7/8	BRDY	LOLO		186	186	32
7/8	BRDY	M345		37,611	37,611	33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp West	SFP
2	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
3	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
4	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
5	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
7	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
8	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
9	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp West	SFP
10	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
11	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
15	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	SFP
17	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
18	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp West	SFP
20	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	SFP
22	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	Avista	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
26	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp West	SFP
27	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
30	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	NF
33	Morgan Stanley Capital Group Inc.			AD
34				
	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	04/15/2016	End of 2015/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	M345		3,885	3,885	1
7/8	ENPR	BORA		1,379	1,379	2
7/8	ENPR	BRDY		146	146	3
7/8	ENPR	M345		8,288	8,288	4
7/8	HMWY	BORA		804	804	5
7/8	HMWY	BRDY		134	134	6
7/8	HMWY	M345		5,033	5,033	7
7/8	JBSN	M345		1,366	1,366	8
7/8	JBSN	M345		4,081	4,081	9
7/8	JBWT	M345		287	287	10
7/8	JEFF	BORA		316	316	11
7/8	JEFF	LAGRANDE		11,344	11,344	12
7/8	JEFF	M345		158,131	158,131	13
7/8	JEFF	M345		1,450	1,450	14
7/8	LAGRANDE	BORA		3,142	3,142	15
7/8	LAGRANDE	BORA		566	566	16
7/8	LAGRANDE	BRDY		1,844	1,844	17
7/8	LAGRANDE	M345		27,130	27,130	18
7/8	LAGRANDE	M345		140	140	19
7/8	LOLO	BORA		6,356	6,356	20
7/8	LOLO	BORA		368	368	21
7/8	LOLO	BRDY		507	507	22
7/8	LOLO	JEFF		32	32	23
7/8	LOLO	LAGRANDE		117	117	24
7/8	LOLO	M345		135,160	135,160	25
7/8	LOLO	M345		191,191	191,191	26
7/8	M345	AVAT.NWMT		451	451	27
7/8	M345	BPAT.NWMT		416	416	28
7/8	M345	BRDY		80	80	29
7/8	M345	JEFF		82	82	30
7/8	M345	LAGRANDE		415	415	31
7/8	M345	LOLO		95	95	32
7/8						33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
2	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
3	Nevada Power Company	Idaho Power Company	Sierra Pacific Power	NF
4	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
5	Nevada Power Company	Bonneville Power Administration	Sierra Pacific Power	NF
6	Nevada Power Company	Avista	Sierra Pacific Power	NF
7	Nevada Power Company	Avista	PacifiCorp West	SFP
8	Nevada Power Company			AD
9	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
10	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
11	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
12	PacifiCorp Inc.	PacifiCorp East	Sierra Pacific Power	NF
13	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
14	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
15	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
16	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
17	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
18	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
19	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
20	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
21	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
22	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
23	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
24	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
25	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	NF
26	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
27	PacifiCorp Inc.	Idaho Power Company	Bonneville Power Administration	NF
28	PacifiCorp Inc.	Idaho Power Company	Avista	NF
29	PacifiCorp Inc.	Avista	PacifiCorp East	NF
30	PacifiCorp Inc.	Avista	PacifiCorp West	NF
31	PacifiCorp Inc.			AD
32	Portland General Electric Company	PacifiCorp East	NorthWestern/PacifiCorp East	NF
33	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
34				
	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	04/15/2016	End of 2015/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	BORA	M345		2,020	2,020	1
7/8	BRDY	M345		1,011	1,011	2
7/8	HMWY	M345		750	750	3
7/8	JEFF	M345		1,409	1,409	4
7/8	LAGRANDE	M345		701	701	5
7/8	LOLO	M345		4,065	4,065	6
7/8	LOLO	M345		2,400	2,400	7
7/8						8
7/8	BORA	ENPR		4,279	4,279	9
7/8	BORA	HMWY		745	745	10
7/8	BORA	HURR		837	837	11
7/8	BORA	M345		48	48	12
7/8	BRDY	BRDY		1,061	1,061	13
7/8	BRDY	BRDY		2,244	2,244	14
7/8	BRDY	ENPR		7,978	7,978	15
7/8	BRDY	KPRT		553	553	16
7/8	BRDY	LAGRANDE		16,396	16,396	17
7/8	ENPR	BORA		136,570	136,570	18
7/8	ENPR	BORA		2,176	2,176	19
7/8	ENPR	BRDY		884	884	20
7/8	HURR	BORA		219	219	21
7/8	HURR	BORA		5,604	5,604	22
7/8	JBWT	BORA		1,126	1,126	23
7/8	JBWT	GSHN		51	51	24
7/8	JBWT	HMWY		4,000	4,000	25
7/8	JBWT	KPRT		4,975	4,975	26
7/8	JBWT	LAGRANDE		154,480	154,480	27
7/8	JBWT	LOLO		1,637	1,637	28
7/8	LOLO	BORA		2,239	2,239	29
7/8	LOLO	ENPR		8,820	8,820	30
7/8						31
7/8	BORA	BPAT.NWMT		250	250	32
7/8	BORA	LAGRANDE		1,670	1,670	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Portland General Electric Company	PacifiCorp East	Sierra Pacific Power	NF
2	Portland General Electric Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Portland General Electric Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
5	Portland General Electric Company	Idaho Power Company	PacifiCorp East	NF
6	Portland General Electric Company	Idaho Power Company	Sierra Pacific Power	NF
7	Portland General Electric Company	Idaho Power Company	PacifiCorp East	NF
8	Portland General Electric Company	Idaho Power Company	Bonneville Power Administration	NF
9	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
10	Portland General Electric Company	Bonneville Power Administration	PacifiCorp East	NF
11	Portland General Electric Company	Bonneville Power Administration	Sierra Pacific Power	NF
12	Portland General Electric Company	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
13	Portland General Electric Company	Sierra Pacific Power	Bonneville Power Administration	NF
14	Portland General Electric Company			AD
15	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
17	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
18	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
19	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
20	Powerex Corporation	PacifiCorp East	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	SFP
24	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
25	Powerex Corporation	NorthWestern/PacifiCorp East	Idaho Power Company	NF
26	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
27	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
28	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
29	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
31	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
32	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
33	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	BORA	M345		2	2	1
7/8	BPAT.NWMT	BORA		200	200	2
7/8	BPAT.NWMT	M345		100	100	3
7/8	BRDY	LAGRANDE		10,396	10,396	4
7/8	HMWY	BORA		1,535	1,535	5
7/8	HMWY	M345		3,900	3,900	6
7/8	JBWT	BORA		114	114	7
7/8	JBWT	LAGRANDE		75	75	8
7/8	JEFF	LAGRANDE		1,435	1,435	9
7/8	LAGRANDE	BORA		979	979	10
7/8	LAGRANDE	M345		813	813	11
7/8	M345	BPAT.NWMT		50	50	12
7/8	M345	LAGRANDE		324	324	13
7/8						14
7/8	AVAT.NWMT	M345		76	76	15
7/8	BORA	BPAT.NWMT		512	512	16
7/8	BORA	ENPR		80	80	17
7/8	BORA	HMWY		525	525	18
7/8	BORA	JEFF		30	30	19
7/8	BORA	LAGRANDE		211	211	20
7/8	BORA	M345		184	184	21
7/8	BPAT.NWMT	BORA		1,558	1,558	22
7/8	BPAT.NWMT	BORA		2,613	2,613	23
7/8	BPAT.NWMT	BRDY		588	588	24
7/8	BPAT.NWMT	IPCOLOSS		43	43	25
7/8	BPAT.NWMT	LAGRANDE		1,012	1,012	26
7/8	BPAT.NWMT	M345		7,276	7,276	27
7/8	BPAT.NWMT	M345		55,295	55,295	28
7/8	BRDY	BPAT.NWMT		213	213	29
7/8	BRDY	HMWY		41	41	30
7/8	BRDY	LAGRANDE		2,849	2,849	31
7/8	BRDY	M345		2,430	2,430	32
7/8	ENPR	BORA		47,641	47,641	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Powerex Corporation	PacifiCorp West	PacifiCorp East	SFP
2	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
3	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
4	Powerex Corporation	PacifiCorp West	PacifiCorp West	SFP
5	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
6	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
7	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
8	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
9	Powerex Corporation	Idaho Power Company	Sierra Pacific Power	NF
10	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
11	Powerex Corporation	Idaho Power Company	Idaho Power Company	NF
12	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
14	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
15	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
16	Powerex Corporation	Bonneville Power Administration	Idaho Power Company	NF
17	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
18	Powerex Corporation	Bonneville Power Administration	PacifiCorp West	SFP
19	Powerex Corporation	Avista	PacifiCorp East	NF
20	Powerex Corporation	Avista	PacifiCorp East	NF
21	Powerex Corporation	Avista	Sierra Pacific Power	NF
22	Powerex Corporation	Avista	PacifiCorp West	SFP
23	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
24	Powerex Corporation	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
25	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
26	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
27	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
28	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
29	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
30	Powerex Corporation			AD
31	Puget Sound Energy, Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
32	Puget Sound Energy, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
33	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
34				
	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	04/15/2016	End of 2015/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	ENPR	BORA		12,700	12,700	1
7/8	ENPR	BRDY		1,590	1,590	2
7/8	ENPR	M345		6,152	6,152	3
7/8	ENPR	M345		2,534	2,534	4
7/8	GSHN	LAGRANDE		905	905	5
7/8	GSHN	M345		60	60	6
7/8	HMWY	BORA		44,475	44,475	7
7/8	HMWY	BRDY		3,587	3,587	8
7/8	HMWY	M345		22,746	22,746	9
7/8	JBSN	M345		49	49	10
7/8	JBWT	HMWY		265	265	11
7/8	JEFF	BORA		25	25	12
7/8	JEFF	BRDY		59	59	13
7/8	LAGRANDE	BORA		15,644	15,644	14
7/8	LAGRANDE	BRDY		3,628	3,628	15
7/8	LAGRANDE	IPCOLOSS		27	27	16
7/8	LAGRANDE	M345		56,732	56,732	17
7/8	LAGRANDE	M345		266	266	18
7/8	LOLO	BORA		885	885	19
7/8	LOLO	BRDY		216	216	20
7/8	LOLO	M345		14,872	14,872	21
7/8	LOLO	M345		7,598	7,598	22
7/8	M345	BORA		125	125	23
7/8	M345	BPAT.NWMT		116	116	24
7/8	M345	JEFF		50	50	25
7/8	M345	LAGRANDE		2,764	2,764	26
7/8	SMLK	BORA		3,003	3,003	27
7/8	SMLK	BRDY		138	138	28
7/8	SMLK	M345		648	648	29
7/8						30
7/8	M345	BPAT.NWMT		1	1	31
7/8	M345	LAGRANDE		40	40	32
7/8	BORA	M345		440	440	33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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	Shell Energy North America (US), L.P.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
2	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
3	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
4	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp West	SFP
5	Shell Energy North America (US), L.P.	PacifiCorp West	Bonneville Power Administration	NF
6	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
7	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
8	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp West	SFP
9	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
10	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
11	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
12	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
13	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
14	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
15	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
16	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	SFP
17	Shell Energy North America (US), L.P.	Bonneville Power Administration	Avista	NF
18	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
19	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp West	SFP
20	Shell Energy North America (US), L.P.	Avista	Idaho Power Company	NF
21	Shell Energy North America (US), L.P.	Avista	Bonneville Power Administration	NF
22	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
23	Shell Energy North America (US), L.P.	Avista	PacifiCorp West	SFP
24	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
25	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
26	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	SFP
27	Shell Energy North America (US), L.P.	Idaho Power Company	Idaho Power Company	NF
28	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
29	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
30	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp West	SFP
31	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
32	Shell Energy North America (US), L.P.	Sierra Pacific Power	Idaho Power Company	NF
33	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
34				
	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	04/15/2016	End of 2015/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	BPAT.NWMT		50	50	1
7/8	BRDY	LAGRANDE		3,387	3,387	2
7/8	BRDY	M345		43,016	43,016	3
7/8	BRDY	M345		68,767	68,767	4
7/8	ENPR	LAGRANDE		36	36	5
7/8	ENPR	M345		1,218	1,218	6
7/8	HMWY	M345		5,144	5,144	7
7/8	HMWY	M345		2,417	2,417	8
7/8	IPCOGEN	BRDY		30	30	9
7/8	IPCOGEN	LAGRANDE		924	924	10
7/8	IPCOGEN	M345		5	5	11
7/8	JEFF	LAGRANDE		182	182	12
7/8	JEFF	M345		651	651	13
7/8	JEFF	M345		1,176	1,176	14
7/8	LAGRANDE	BRDY		1,040	1,040	15
7/8	LAGRANDE	BRDY		900	900	16
7/8	LAGRANDE	LOLO		56	56	17
7/8	LAGRANDE	M345		98,756	98,756	18
7/8	LAGRANDE	M345		1,216	1,216	19
7/8	LOLO	IPCO		56	56	20
7/8	LOLO	LAGRANDE		68	68	21
7/8	LOLO	M345		7,660	7,660	22
7/8	LOLO	M345		16,512	16,512	23
7/8	LYPK	BORA		230	230	24
7/8	LYPK	BRDY		19,241	19,241	25
7/8	LYPK	BRDY		5,464	5,464	26
7/8	LYPK	HMWY		71	71	27
7/8	LYPK	LAGRANDE		10,872	10,872	28
7/8	LYPK	M345		77,800	77,800	29
7/8	LYPK	M345		132,217	132,217	30
7/8	M345	BRDY		50	50	31
7/8	M345	HMWY		248	248	32
7/8	M345	LAGRANDE		4,397	4,397	33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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.	Idaho Power Company	Bonneville Power Administration	NF
2	Shell Energy North America (US), L.P.	Idaho Power Company	Avista	NF
3	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
4	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
5	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp West	SFP
6	Shell Energy North America (US), L.P.			AD
7	Talen Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	Talen Energy	PacifiCorp East	Idaho Power Company	NF
9	Talen Energy	PacifiCorp East	Idaho Power Company	NF
10	Talen Energy	PacifiCorp East	Bonneville Power Administration	NF
11	Talen Energy	Idaho Power Company	PacifiCorp East	NF
12	Talen Energy	Idaho Power Company	Sierra Pacific Power	NF
13	Talen Energy	PacifiCorp East	PacifiCorp East	NF
14	Talen Energy	PacifiCorp East	Bonneville Power Administration	NF
15	Talen Energy	Avista	PacifiCorp East	NF
16	Talen Energy	Sierra Pacific Power	PacifiCorp East	NF
17	Talen Energy			AD
18	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Tenaska Power Services Co.	PacifiCorp East	Bonneville Power Administration	NF
20	Tenaska Power Services Co.	PacifiCorp East	Sierra Pacific Power	NF
21	Tenaska Power Services Co.	PacifiCorp East	Sierra Pacific Power	NF
22	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
24	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
26	The Energy Authority, Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	The Energy Authority, Inc.	PacifiCorp East	Idaho Power Company	NF
28	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
29	The Energy Authority, Inc.	Idaho Power Company	PacifiCorp East	NF
30	The Energy Authority, Inc.	Idaho Power Company	PacifiCorp East	NF
31	The Energy Authority, Inc.	Idaho Power Company	Sierra Pacific Power	NF
32	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
33	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
34				
	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	04/15/2016	End of 2015/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.
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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	MDSK	LAGRANDE		451	451	1
7/8	MDSK	LOLO		50	50	2
7/8	OBBLPR	LAGRANDE		135	135	3
7/8	SMLK	M345		1,082	1,082	4
7/8	SMLK	M345		4,192	4,192	5
7/8						6
7/8	BPAT.NWMT	LAGRANDE		15	15	7
7/8	BRDY	IPCO		1,800	1,800	8
7/8	BRDY	IPCOEAST		150	150	9
7/8	BRDY	LAGRANDE		2,082	2,082	10
7/8	HMWY	BRDY		1,340	1,340	11
7/8	HMWY	M345		950	950	12
7/8	JEFF	BRDY		210	210	13
7/8	JEFF	LAGRANDE		447	447	14
7/8	LOLO	BRDY		175	175	15
7/8	M345	BRDY		100	100	16
7/8						17
7/8	BPAT.NWMT	M345		100	100	18
7/8	BRDY	LAGRANDE		167	167	19
7/8	BRDY	M345		250	250	20
7/8	JEFF	M345		900	900	21
7/8	BPAT.NWMT	BORA		4,972	4,972	22
7/8	BPAT.NWMT	BORA		400	400	23
7/8	BPAT.NWMT	M345		2,368	2,368	24
7/8	BPAT.NWMT	M345		11,713	11,713	25
7/8	BRDY	BPAT.NWMT		545	545	26
7/8	BRDY	HMWY		25	25	27
7/8	BRDY	LAGRANDE		1,182	1,182	28
7/8	HMWY	BORA		190	190	29
7/8	HMWY	BRDY		161	161	30
7/8	HMWY	M345		50	50	31
7/8	LAGRANDE	BORA		270	270	32
7/8	LAGRANDE	BRDY		7,444	7,444	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
2	The Energy Authority, Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF
4	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
5	The Energy Authority, Inc.			AD
6	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Idaho Power Company	NF
7	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
8	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
9	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
10	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
11	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
12	Transalta Energy Marketing (U.S.) Inc.	Avista	PacifiCorp East	NF
13	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
14	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
15	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	PacifiCorp East	NF
16	Transalta Energy Marketing (U.S.) Inc.			AD
17	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
18	Utah Associated Municipal Power			AD
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	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	04/15/2016	End of 2015/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	LAGRANDE	M345		1,493	1,493	1
7/8	M345	BPAT.NWMT		202	202	2
7/8	M345	BRDY		45	45	3
7/8	M345	LAGRANDE		504	504	4
7/8						5
7/8	BORA	HMWY		292	292	6
7/8	BORA	LAGRANDE		1,136	1,136	7
7/8	HMWY	BORA		36,005	36,005	8
7/8	HMWY	M345		906	906	9
7/8	LAGRANDE	BORA		3,324	3,324	10
7/8	LAGRANDE	M345		2,407	2,407	11
7/8	LOLO	BORA		150	150	12
7/8	M345	BPAT.NWMT		165	165	13
7/8	M345	LAGRANDE		1,550	1,550	14
7/8	SMLK	BORA		575	575	15
7/8						16
7/8	BORA	M345		4,288	4,288	17
7/8						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**5,920,350**	**5,920,350**	

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	04/15/2016	End of 2015/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.
1,356,463	134,488		1,490,951	1
-3,155			-3,155	2
1,450,555	84,591		1,535,146	3
-1,609			-1,609	4
4,870,927	479,709		5,350,636	5
-10,878			-10,878	6
8,391	1,032		9,423	7
-19			-19	8
	15,217		15,217	9
54,752			54,752	10
	65,123		65,123	11
	6		6	12
	7,766		7,766	13
	8,096		8,096	14
				15
				16
				17
	269,445		269,445	18
	941,105		941,105	19
	3,776,788		3,776,788	20
	766,651		766,651	21
	2,294,437		2,294,437	22
				23
	643		643	24
	5,808		5,808	25
	1,128		1,128	26
	3,292		3,292	27
	45,877		45,877	28
	13,547		13,547	29
	8,299		8,299	30
	-482		-482	31
	-13		-13	32
	167		167	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	481		481	1
	167		167	2
	259		259	3
	13,746		13,746	4
	2,656		2,656	5
	586		586	6
	6,982		6,982	7
	40,014		40,014	8
	167		167	9
	7,371		7,371	10
	5,078		5,078	11
	1,046		1,046	12
	-488		-488	13
	3,210		3,210	14
	1,178		1,178	15
	95		95	16
	3,262		3,262	17
	181,699		181,699	18
	112,245		112,245	19
	1,563		1,563	20
	12,147		12,147	21
	5,145		5,145	22
	2,332		2,332	23
	25,612		25,612	24
	24,877		24,877	25
	20,513		20,513	26
	72		72	27
	2,058		2,058	28
	2,313		2,313	29
	38		38	30
	39,558		39,558	31
	709		709	32
	143,349		143,349	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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	04/15/2016	End of 2015/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.
	14,807		14,807	1
	5,256		5,256	2
	556		556	3
	31,588		31,588	4
	3,064		3,064	5
	511		511	6
	19,182		19,182	7
	5,206		5,206	8
	15,554		15,554	9
	1,094		1,094	10
	1,204		1,204	11
	43,236		43,236	12
	602,695		602,695	13
	5,526		5,526	14
	11,975		11,975	15
	2,157		2,157	16
	7,028		7,028	17
	103,402		103,402	18
	534		534	19
	24,225		24,225	20
	1,403		1,403	21
	1,932		1,932	22
	122		122	23
	446		446	24
	515,144		515,144	25
	728,698		728,698	26
	1,719		1,719	27
	1,586		1,586	28
	305		305	29
	313		313	30
	1,582		1,582	31
	362		362	32
	-9,194		-9,194	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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	04/15/2016	End of 2015/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.
	7,647		7,647	1
	3,827		3,827	2
	2,839		2,839	3
	5,334		5,334	4
	2,654		2,654	5
	21,739		21,739	6
	2,736		2,736	7
	-67		-67	8
	31,277		31,277	9
	5,446		5,446	10
	6,118		6,118	11
	351		351	12
	7,755		7,755	13
	16,403		16,403	14
	58,315		58,315	15
	4,042		4,042	16
	119,847		119,847	17
	998,262		998,262	18
	15,905		15,905	19
	6,462		6,462	20
	1,601		1,601	21
	40,963		40,963	22
	8,231		8,231	23
	373		373	24
	29,238		29,238	25
	36,365		36,365	26
	1,129,176		1,129,176	27
	11,966		11,966	28
	16,366		16,366	29
	64,470		64,470	30
	-12,044		-12,044	31
	1,030		1,030	32
	6,879		6,879	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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	04/15/2016	End of 2015/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.
	8		8	1
	824		824	2
	412		412	3
	42,822		42,822	4
	6,323		6,323	5
	16,065		16,065	6
	470		470	7
	309		309	8
	5,911		5,911	9
	4,033		4,033	10
	3,349		3,349	11
	206		206	12
	1,335		1,335	13
	-540		-540	14
	348		348	15
	2,347		2,347	16
	367		367	17
	2,406		2,406	18
	137		137	19
	967		967	20
	843		843	21
	7,140		7,140	22
	11,976		11,976	23
	2,695		2,695	24
	197		197	25
	4,638		4,638	26
	33,346		33,346	27
	253,420		253,420	28
	976		976	29
	188		188	30
	13,057		13,057	31
	11,137		11,137	32
	218,342		218,342	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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	04/15/2016	End of 2015/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.
	58,205		58,205	1
	7,287		7,287	2
	28,195		28,195	3
	11,613		11,613	4
	4,148		4,148	5
	275		275	6
	203,832		203,832	7
	16,439		16,439	8
	104,246		104,246	9
	225		225	10
	1,215		1,215	11
	115		115	12
	270		270	13
	71,697		71,697	14
	16,627		16,627	15
	124		124	16
	260,006		260,006	17
	1,219		1,219	18
	4,056		4,056	19
	990		990	20
	68,159		68,159	21
	34,822		34,822	22
	573		573	23
	532		532	24
	229		229	25
	12,668		12,668	26
	13,763		13,763	27
	632		632	28
	2,970		2,970	29
	-3,506		-3,506	30
	8		8	31
	300		300	32
	67		67	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	8		8	1
	515		515	2
	6,536		6,536	3
	10,449		10,449	4
	5		5	5
	185		185	6
	782		782	7
	367		367	8
	5		5	9
	140		140	10
	1		1	11
	28		28	12
	99		99	13
	179		179	14
	158		158	15
	137		137	16
	9		9	17
	15,006		15,006	18
	185		185	19
	9		9	20
	10		10	21
	1,164		1,164	22
	2,509		2,509	23
	35		35	24
	2,924		2,924	25
	830		830	26
	11		11	27
	1,652		1,652	28
	11,822		11,822	29
	20,090		20,090	30
	8		8	31
	38		38	32
	668		668	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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	04/15/2016	End of 2015/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.
	69		69	1
	8		8	2
	21		21	3
	164		164	4
	637		637	5
	-6,180		-6,180	6
	69		69	7
	8,306		8,306	8
	692		692	9
	9,608		9,608	10
	6,184		6,184	11
	4,384		4,384	12
	969		969	13
	2,063		2,063	14
	808		808	15
	461		461	16
	-807		-807	17
	465		465	18
	776		776	19
	1,162		1,162	20
	4,182		4,182	21
	22,334		22,334	22
	1,797		1,797	23
	10,637		10,637	24
	52,615		52,615	25
	2,448		2,448	26
	112		112	27
	5,310		5,310	28
	853		853	29
	723		723	30
	225		225	31
	1,213		1,213	32
	33,438		33,438	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	6,707		6,707	1
	907		907	2
	202		202	3
	2,264		2,264	4
	-56		-56	5
	1,188		1,188	6
	4,620		4,620	7
	146,443		146,443	8
	3,685		3,685	9
	13,520		13,520	10
	9,790		9,790	11
	610		610	12
	671		671	13
	6,304		6,304	14
	2,339		2,339	15
	-520		-520	16
	17,587		17,587	17
	-165		-165	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

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

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30, 2028. 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.: 6 Column: h

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2016. 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.: 8 Column: h

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328 Line No.: 9 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 9 Column: h

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

Schedule Page: 328 Line No.: 10 Column: h

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.: 11 Column: e

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

Schedule Page: 328 Line No.: 11 Column: h

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 Shell and Shell is now responsible for payment.

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

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

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

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.: 13 Column: h

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.

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Schedule Page: 328 Line No.: 14 Column: h
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.: 15 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328 Line No.: 17 Column: e
7/8, Open Access Transmission Tariff, Schedule 7/8 Point-to-Point Transmission Service

Schedule Page: 328 Line No.: 17 Column: h
Legacy agreement providing OATT-like service, but billed under 454 Facilities revenue.

Schedule Page: 328 Line No.: 31 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328 Line No.: 32 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.1 Line No.: 13 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.2 Line No.: 33 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.3 Line No.: 8 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.3 Line No.: 31 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.4 Line No.: 14 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.5 Line No.: 30 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.7 Line No.: 6 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.7 Line No.: 17 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 5 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 16 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 18 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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	04/15/2016	End of 2015/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	Avista Corp-WWP Div	NF	29,184	29,184		214,621		214,621
2	Avista Corp-WWP Div	SFP	144,542	144,542		802,613		802,613
3	Avista Corp-WWP Div	OS					-802	-802
4	Bonneville Power Admin	LFP	179,776	179,776		3,200,575		3,200,575
5	Bonneville Power Admin	SFP	321,574	321,574		24,107		24,107
6	Bonneville Power Admin	NF	540	540		2,473		2,473
7	Bonneville Power Admin	OS					15,312	15,312
8	Bonneville Power Admin	OS					521,220	521,220
9	Bonneville Power Adminn	AD					29,754	29,754
10	Bonneville Power Adminn	AD					-48,769	-48,769
11	Bonneville Power Adminn	OS	811	811				
12	Exelon Generation Co	OS					-65,522	-65,522
13	Iberdrola Renewables	OS					-3,087	-3,087
14	Morgan Stanley Capital	OS					-725	-725
15	Nevada Power Company	SFP	14,850	14,850		132,500		132,500
16	Nevada Power Company	NF	328	328		2,150		2,150
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

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	04/15/2016	End of 2015/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)	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	Nevada Power Company	OS					19,540	19,540
2	NextEra Energy	OS					-3,522	-3,522
3	NorthWestern Energy	NF	7,775	7,775		74,353		74,353
4	NorthWestern Energy	SFP	1,985	1,985		10,509		10,509
5	NorthWestern Energy	OS					4,410	4,410
6	PacifiCorp Inc.	LFP	63,546	63,546		928,749		928,749
7	PacifiCorp Inc.	NF	38,104	38,104		208,077		208,077
8	PacifiCorp Inc.	SFP	115,328	115,328		125,584		125,584
9	PacifiCorp Inc.	OS					-2,048	-2,048
10	PacifiCorp Inc.	OS					-65,539	-65,539
11	PacifiCorp Inc.	OS					28	28
12	PacifiCorp Inc.	OS					58,436	58,436
13	Powerex Corp.	OS					-57,056	-57,056
14	Puget Sound Energy, Inc	SFP				187,620		187,620
15	Shell Energy N. America	SFP				600		600
16	Shell Energy N. America	OS					-1,736	-1,736
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

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	04/15/2016	End of 2015/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	TransAlta Energy U.S.	OS					-35,292	-35,292
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

FOOTNOTE DATA

Schedule Page: 332 Line No.: 3 Column: a
Unreserved Use Penalty

Schedule Page: 332 Line No.: 4 Column: b
Contract Expiration Date 09/30/2016

Schedule Page: 332 Line No.: 7 Column: a
Spinning/Supplemental Reserves

Schedule Page: 332 Line No.: 8 Column: a
Ancillary Services

Schedule Page: 332 Line No.: 9 Column: a
Correction of refund for System Control and Dispatch Charges in 2013

Schedule Page: 332 Line No.: 10 Column: a
Refund of Adjustment for System Control and Dispatch Charges.

Schedule Page: 332 Line No.: 11 Column: a
BPAT is provider for transmission services settled with PSEMKT.

Schedule Page: 332 Line No.: 12 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 13 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 14 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 1 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 5 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 6 Column: b
Contract Expiration Date 05/31/2019.

Schedule Page: 332.1 Line No.: 11 Column: a
Energy Imbalance Market

Schedule Page: 332.1 Line No.: 12 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 13 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 14 Column: a
BPAT is provider for transmission services settled with PSEMKT

Schedule Page: 332.1 Line No.: 16 Column: a
Resale Transmission

Schedule Page: 332.2 Line No.: 1 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	04/15/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	505,604
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,602,436
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	64,833
6		
7	Director Fees and Expenses:	
8	Christine King	88,359
9	Dennis Johnson	70,290
10	J Lamont Keen	64,350
11	Jan Packwood	26,812
12	Joan Smith	35,395
13	Judith Johansen	78,331
14	Richard Dahl	91,575
15	Richard Navarro	65,066
16	Robert Tintsman	170,775
17	Ronald Jibson	74,473
18	Thomas Carlile	76,230
19	Thomas Wilford	30,571
20		
21	Corporate Memberships and Subscriptions:	
22	Arizona State University	50,000
23	Associated Taxpayers of Idaho	22,000
24	Boston College for Corporations	5,000
25	Business Plus	5,000
26	Ceati International	13,350
27	Corporate Executive Board	87,535
28	Idaho Association of Commerce & Industry	15,000
29	Idaho Technology Council	12,500
30	National Association of Directors	7,125
31	National Hydropower Association	36,069
32	North American Energy Standard	7,000
33	Northwest Power Pool	342,472
34	Pacific NW Utilities	40,160
35	SNL Financial Unlimited Subscription	23,200
36	Western Alliance for Economic	2,500
37	Western Energy Coordinating Council	1,604,339
38	Western Energy Institute	30,794
39	Misc Memberships Under $2,000	5,574
40		
41	Chambers of Commerce & Other Civic Organizations	
42		90,135
43		
44		
45		
46	TOTAL	5,444,853

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Mgmt Services	$ 65,293
Bloomberg Finance LP	Misc Expense	10,146
Broadridge Financial Solutions	Misc Expense	46,949
Deutsche Bank	Broker Fees	30,000
E Source	Mgmt Services	39,906
Moody's Analytics	Mgmt Services	32,310
NASDAQ Corp Solutions	Mgmt Services	62,573
New York Stock Exchange	Listing Services	50,163
Payroll Related Expenses	Misc Expense	175,051
PR Newswire	Misc Expense	14,813
Rivel Research Group	Mgmt Services	15,840
Stock Based Compensation	Misc Expense	949,993
Wells Fargo Shareowner Services	Mgmt Services	107,626
Miscellaneous under $5,000	Misc Expense	1,773

		$ 1,602,436
		=======

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

Recipient	Purpose	Amount
Bank of New York	Revenue Bonds	$ 13,925
Payroll Related Expense	Misc Expense	22,311
Total Electric	Misc Expense	5,175
Union Bank	Revenue Bonds	9,680
Miscellaneous under $5,000	Misc Expense	13,742

		$ 64,833
		======

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	04/15/2016	End of 2015/Q4

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			7,095,926		7,095,926
2	Steam Production Plant	25,480,959	549,017			26,029,976
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,513,923				14,513,923
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,072,839				17,072,839
7	Transmission Plant	20,991,260				20,991,260
8	Distribution Plant	41,882,379				41,882,379
9	Regional Transmission and Market Operation					
10	General Plant	10,440,768				10,440,768
11	Common Plant-Electric					
12	TOTAL	130,382,128	549,017	7,095,926		138,027,071

B. Basis for Amortization Charges

Acct 404	Balance 1/1/2015	2015 Amortization	Balance 12/31/2015	Remaining Months
(1)	36,000	12,000	24,000	24
(2)	10,339,996	545,446	9,794,550	-
(3)	5,251,629	189,064	5,062,565	321
(4)	15,747,708	6,035,788	13,191,811	-
(5)	3,747,997	287,899	3,460,098	156
(6)	201,821	8,026	193,795	-
(7)	604,625	17,702	878,552	-
	---------------	--------------	----------------	
Total	35,929,777	7,095,926	32,605,372	

(1) Shoshone-Bannock Tribe License & Use Agreement(Termination date December 31, 2023).
(2) Middle Snake Relicesing Costs (Amortized over a 30 year license period).
(3) Swan Falls Relicesing 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 December 31, 2028).
(6) Boardman Retrofit Tech Analysis (Termination date December 31,2040)
(7) FERC License Compliance Costs (Termination date will be expiration date of the FERC Licenses)

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	04/15/2016	End of 2015/Q4

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	657	75.00		3.63	R4.0	20.20
13	311.00	153,408	100.00	-10.00	1.84	S1.0	21.30
14	312.10	133,426	60.00	-5.00	1.15	R3.0	21.80
15	312.20	545,122	60.00	-5.00	2.77	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.36	R3.0	7.90
17	314.00	162,544	45.00	-5.00	3.25	S1.0	19.40
18	315.00	70,702	60.00		1.44	S1.5	19.80
19	316.00	12,808	45.00	-5.00	3.75	R0.5	19.00
20	316.10	84	12.00	15.00	8.72	L2.0	6.30
21	316.40	247	12.00	15.00	0.87	L2.0	7.90
22	316.50	310	12.00	15.00	5.60	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	3,855	20.00	30.00	3.52	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	13,930					
28	Subtotal Steam	1,101,634					
29	331.00	175,996	105.00	-25.00	2.40	R2.5	33.00
30	332.10	19,460	95.00	-20.00	1.31	S4.0	39.80
31	332.20	245,027	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	SQUARE	49.10
33	333.00	211,679	80.00	-5.00	1.73	R3.0	32.60
34	334.00	58,474	50.00	-5.00	2.75	R1.5	26.10
35	335.00	22,054	95.00		2.28	R2.0	28.10
36	335.10	88	15.00		6.77	SQUARE	6.50
37	335.20	366	20.00		5.57	SQUARE	5.30
38	335.30	288	5.00		12.90	SQUARE	3.30
39	336.00	10,881	75.00		2.22	R3.0	21.40
40	Subtotal Hydro	749,785					
41	341.00	142,711			2.89	SQUARE	27.20
42	342.00	10,453	50.00		2.98	S2.5	28.50
43	343.00	218,961	40.00		3.46	S1.5	25.90
44	344.00	66,532	45.00		2.45	S2.0	26.80
45	345.00	91,099	50.00		3.23	S1.5	22.60
46	346.00	6,010	35.00		3.40	R2.5	24.50
47	Subtotal Other	535,766					
48	350.20	31,780	70.00		1.39	R3.0	58.50
49	350.22	171	30.00		2.93		
50	352.00	77,780	65.00	-35.00	1.84	R3.0	53.70

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	04/15/2016	End of 2015/Q4

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	407,603	50.00	-5.00	1.90	R1.5	40.70
13	354.00	184,628	65.00	-15.00	1.65	S3.0	50.80
14	355.00	157,531	60.00	-70.00	2.70	R2.0	43.60
15	355.10	849	10.00		7.78		
16	356.00	211,905	65.00	-40.00	2.19	R2.0	48.50
17	359.00	390	65.00		0.79	R2.5	24.00
18	Subtotal Transmission	1,072,637					
19	360.22	476	30.00		3.49		30.00
20	361.00	34,175	65.00	-40.00	2.13	R2.5	53.30
21	362.00	216,854	50.00	-5.00	1.98	R1.0	40.20
22	364.00	244,791	44.00	-45.00	3.06	R1.5	31.30
23	364.10	2,195	12.00		7.55		
24	365.00	129,331	45.00	-35.00	2.96	R0.5	33.60
25	366.00	48,323	60.00	-20.00	1.93	R2.0	48.40
26	367.00	230,143	46.00	-15.00	2.23	R2.0	35.30
27	368.00	515,652	35.00	-3.00	2.57	R1.0	27.00
28	369.00	58,771	40.00	-40.00	2.54	R2.0	29.50
29	370.00	16,979	22.00	1.00	3.46	O1.0	17.50
30	370.10	68,269	15.00		6.88	S2.5	13.10
31	371.10		12.00	-2.00		S4.0	9.00
32	371.20	2,954	17.00	-2.00	1.51	R1.5	14.70
33	373.20	4,543	30.00	-25.00	2.41	R1.0	20.60
34	374.00	164					
35	Subtotal Distribution	1,573,620					
36	390.11	29,421	100.00	-5.00	2.57	S0.5	28.80
37	390.12	81,504	55.00	-5.00	1.89	S0.5	44.30
38	390.20		35.00		3.94	S3.0	25.70
39	391.10	14,155	20.00		2.92	SQUARE	12.90
40	391.20	24,594	5.00		11.73	SQUARE	3.20
41	391.21	7,944	8.00		11.50	L2.0	5.70
42	392.10	822	12.00	15.00	7.39	L2.0	8.90
43	392.30	4,563	10.00	50.00	2.06	S2.5	3.40
44	392.40	23,290	12.00	15.00	7.03	L2.0	6.80
45	392.50	1,127	12.00	15.00	3.33	L2.0	9.00
46	392.60	34,103	20.00	15.00	4.03	L2.0	13.40
47	392.70	6,944	20.00	15.00	3.12	L2.0	12.50
48	392.90	5,031	35.00	15.00	2.05	S1.0	24.30
49	393.00	2,255	25.00		3.18	SQUARE	19.40
50	394.00	8,022	20.00		4.14	SQUARE	13.30

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	04/15/2016	End of 2015/Q4

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	12,704	20.00		4.31	SQUARE	12.10
13	396.00	15,082	20.00	30.00	1.57	O1.0	17.60
14	397.10	4,672	15.00		4.41	SQUARE	8.30
15	397.20	30,517	15.00		5.44	SQUARE	9.80
16	397.30	3,472	15.00		6.03	SQUARE	8.00
17	397.40	16,754	10.00		7.44	SQUARE	6.50
18	398.00	5,968	15.00		5.19	SQUARE	10.60
19	Subtotal General	332,944					
20	Total Plant	5,366,386					
21							
22							
23							
24							
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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 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 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 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	04/15/2016	End of 2015/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	3,306,791		3,306,791	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		17,061	17,061	
6					
7	Oregon Hydro - Fees Amortization	158,501		158,501	
8					
9	Regulatory Commission Expenses - Idaho				
10	Rate Case - Misc expenses		1,066	1,066	
11					
12	Regulatory Commission Expenses - Oregon				
13	Rate Case - Misc expenses		138	138	
14	General Regulatory		111,541	111,541	
15	Other OPUC expenses		21,159	21,159	
16					
17					
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19					
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45					
46	TOTAL	3,465,292	150,965	3,616,257	

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	04/15/2016	End of 2015/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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	3,306,791					2
							3
							4
Electric	928	17,061					5
							6
Electric	928	158,501					7
							8
							9
Electric	928	1,066					10
							11
							12
Electric	928	138					13
Electric	928	111,541					14
Electric	928	21,159					15
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		3,616,257					46

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	04/15/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & 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 2015.	
3		
4		
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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	04/15/2016	End of 2015/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		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					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	04/15/2016	End of 2015/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	23,391,734		
4	Transmission	7,150,122		
5	Regional Market			
6	Distribution	19,443,315		
7	Customer Accounts	11,146,099		
8	Customer Service and Informational	5,063,852		
9	Sales			
10	Administrative and General	45,969,645		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	112,164,767		
12	Maintenance			
13	Production	4,962,423		
14	Transmission	3,482,962		
15	Regional Market			
16	Distribution	8,340,987		
17	Administrative and General	963,324		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,749,696		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	28,354,157		
21	Transmission (Enter Total of lines 4 and 14)	10,633,084		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	27,784,302		
24	Customer Accounts (Transcribe from line 7)	11,146,099		
25	Customer Service and Informational (Transcribe from line 8)	5,063,852		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	46,932,969		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	129,914,463		129,914,463
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			

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	04/15/2016	End of 2015/Q4

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)	129,914,463		129,914,463
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	5,289,704		5,289,704
79	Other Clearing Accounts	3,200,159		3,200,159
80	Construction Work in Progress	57,439,811		57,439,811
81	Other Work in Progress	3,287,058		3,287,058
82	Paid Absences	23,344,477		23,344,477
83	Preliminary Survey and Investigation	4,463		4,463
84	Other Accounts	5,389,068		5,389,068
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	97,954,740		97,954,740
96	TOTAL SALARIES AND WAGES	227,869,203		227,869,203

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	04/15/2016	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (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			563,957			
2	Reactive Supply and Voltage			39,649			
3	Regulation and Frequency Response				3,202,871	KW	313,721
4	Energy Imbalance				-2,946	KWH	-15,107
5	Operating Reserve - Spinning			7,991	4,154,060	KW	406,890
6	Operating Reserve - Supplement			7,321	4,154,060	KW	406,890
7	Other						
8	Total (Lines 1 thru 7)			618,918	11,508,045		1,112,394

Schedule Page: 398   Line No.: 8   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: Idaho Power Company

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	4,700	2	1000	3,850	242	463		145	
2	February	4,275	19	800	3,137	184	463		491	
3	March	4,422	5	800	3,326	211	463		422	
4	Total for Quarter 1				10,313	637	1,389		1,058	
5	April	4,476	21	1900	3,396	259	463		358	
6	May	4,719	4	2100	3,533	285	463		438	
7	June	5,934	26	1700	4,818	373	463		280	
8	Total for Quarter 2				11,747	917	1,389		1,076	
9	July	6,016	1	1800	4,979	376	463		198	
10	August	5,623	13	1500	4,458	307	463		395	
11	September	5,048	1	2000	4,070	293	463		222	
12	Total for Quarter 3				13,507	976	1,389		815	
13	October	4,281	10	1700	3,375	170	463		273	
14	November	3,208	30	1900	2,103	234	773		98	
15	December	3,257	1	800	1,851	244	773		389	
16	Total for Quarter 4				7,329	648	2,009		760	
17	Total Year to Date/Year				42,896	3,178	6,176		3,709	

Schedule Page: 400 Line No.: 17 Column: e

Firm Network Service for Self, includes 1836 MW associated with pre-Order No. 888 transmission agreements between PacifiCorp and Idaho Power. The contract demand associated with the pre-Order No. 888 transmission agreements is part of Idaho Power's total firm load and is included in the load denominator in the computation of, and accordance with, Idaho Power's Open Access Transmission Tariff ("OATT") rate. On October 24, 2014, the Parties entered into a Joint Purchase and Sale Agreement and a Termination Agreement that resulted in the elimination of 1836 MW of contract demand that is associated with the pre-Order No. 888 transmission agreements that terminate upon closing of the transaction. The Parties received all required regulatory approvals and the transaction closed October 30, 2015.

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	04/15/2016	End of 2015/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)	14,264,493
3	Steam	4,676,370			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	5,909,916			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,254,136
7	Other	2,075,731			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	12,662,017	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	3,788,934	27	Total Energy Losses	1,051,718
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,570,347
12	Received	276,510			
13	Delivered	162,239			
14	Net Exchanges (Line 12 minus line 13)	114,271			
15	Transmission For Other (Wheeling)				
16	Received	5,920,350			
17	Delivered	5,915,225			
18	Net Transmission for Other (Line 16 minus line 17)	5,125			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	16,570,347			

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	04/15/2016	End of 2015/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

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,429,454	162,212	2,168	2	9 AM
30	February	1,215,125	205,779	1,993	23	8 AM
31	March	1,214,436	167,129	1,919	4	8 AM
32	April	1,212,235	35,621	1,997	28	10 PM
33	May	1,304,647	103,313	2,156	4	8 PM
34	June	1,718,107	62,532	3,402	30	4 PM
35	July	1,747,644	109,737	3,360	1	7 PM
36	August	1,644,547	30,741	3,221	12	6 PM
37	September	1,270,259	62,870	2,473	1	7 PM
38	October	1,186,337	138,462	1,814	10	6 PM
39	November	1,209,550	66,026	2,203	30	7 PM
40	December	1,418,006	109,714	2,241	1	8 AM
41	TOTAL	16,570,347	1,254,136			

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FOOTNOTE DATA

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

Page 329 Column I differs from page 401 by 5,125 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	04/15/2016	End of 2015/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)	727			64		
7	Plant Hours Connected to Load	8760			5017		
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	4096050000			182941000		
13	Cost of Plant: Land and Land Rights	517720			106610		
14	Structures and Improvements	70396751			12492016		
15	Equipment Costs	546181648			63613298		
16	Asset Retirement Costs	9755694			4431431		
17	Total Cost	626851813			80643355		
18	Cost per KW of Installed Capacity (line 17/5) Including	813.5650			1256.1270		
19	Production Expenses: Oper, Supv, & Engr	234643			397405		
20	Fuel	116084606			4737072		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5914375			771734		
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	6301917			393762		
27	Rents	432038			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	109988			12840		
30	Maintenance of Structures	0			87640		
31	Maintenance of Boiler (or reactor) Plant	7602363			223505		
32	Maintenance of Electric Plant	2550850			1967645		
33	Maintenance of Misc Steam (or Nuclear) Plant	6711067			46900		
34	Total Production Expenses	145941847			8638503		
35	Expenses per Net KWh	0.0356			0.0472		
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	2303826	6262	0	111192	1083	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9173	140000	0	8559	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	48.729	108.869	0.000	39.377	76.795	0.000
41	Average Cost of Fuel per Unit Burned	50.038	90.059	0.000	41.435	105.956	0.000
42	Average Cost of Fuel Burned per Million BTU	2.722	15.316	0.000	2.464	18.182	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.026	0.000	0.000
44	Average BTU per KWh Net Generation	10347.000	0.000	0.000	10255.000	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	04/15/2016	End of 2015/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			252			185			6
7664			1538			1023			7
0			261			164			8
0			0			0			9
0			0			0			10
0			8			4			11
249740000			255025000			157875000			12
1106140			402745			0			13
70519961			6087725			1688442			14
323843957			100153211			51991319			15
-257063			0			0			16
395212995			106643681			53679761			17
1394.0494			393.6644			310.6468			18
655838			192181			12812			19
10464678			9729462			6071381			20
0			0			0			21
3105502			0			0			22
0			0			0			23
0			0			0			24
1262175			539906			471697			25
-19410			311203			152790			26
0			0			0			27
0			0			0			28
4165			0			0			29
790432			134240			135606			30
6035691			2151			5795			31
894058			246946			234934			32
165285			0			0			33
23358414			11156089			7085015			34
0.0935			0.0437			0.0449			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
139920	12293	0	2547925	0	0	1601807	0	0	38
11398	138778	0	1027	0	0	1027	0	0	39
36.239	88.175	0.000	3.819	0.000	0.000	3.790	0.000	0.000	40
67.361	83.462	0.000	3.819	0.000	0.000	3.790	0.000	0.000	41
3.725	14.319	0.000	3.200	0.000	0.000	3.180	0.000	0.000	42
0.042	0.000	0.000	0.038	0.000	0.000	0.038	0.000	0.000	43
10419.000	0.000	0.000	10261.000	0.000	0.000	10420.000	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	04/15/2016	End of 2015/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)	301			0		
7	Plant Hours Connected to Load	6132			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	22			0		
12	Net Generation, Exclusive of Plant Use - KWh	1662770000			0		
13	Cost of Plant: Land and Land Rights	2287261			0		
14	Structures and Improvements	134922940			0		
15	Equipment Costs	240012947			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	377223148			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1184.5601			0		
19	Production Expenses: Oper, Supv, & Engr	310438			0		
20	Fuel	39140394			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	3592304			0		
26	Misc Steam (or Nuclear) Power Expenses	350000			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	93848			0		
31	Maintenance of Boiler (or reactor) Plant	32341			0		
32	Maintenance of Electric Plant	788337			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	44307662			0		
35	Expenses per Net KWh	0.0266			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	11344468	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	3.450	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.450	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.950	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7007.000	0.000	0.000	0.000	0.000	0.000

FOOTNOTE DATA

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	04/15/2016	End of 2015/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)	95	54
7	Plant Hours Connect to Load	6,909	8,727
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	294,308,000	311,673,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,986,636	1,098,135
16	Reservoirs, Dams, and Waterways	4,293,075	8,963,581
17	Equipment Costs	32,331,624	9,463,703
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,325,929	20,780,262
21	Cost per KW of Installed Capacity (line 20 / 5)	545.2430	277.0702
22	Production Expenses		
23	Operation Supervision and Engineering	209,916	814,397
24	Water for Power	1,530,108	870,028
25	Hydraulic Expenses	136,364	964,512
26	Electric Expenses	83,114	46,371
27	Misc Hydraulic Power Generation Expenses	277,549	449,505
28	Rents	137	3,405
29	Maintenance Supervision and Engineering	8,576	5,976
30	Maintenance of Structures	158,788	44,538
31	Maintenance of Reservoirs, Dams, and Waterways	6,128	67,464
32	Maintenance of Electric Plant	304,393	115,994
33	Maintenance of Misc Hydraulic Plant	67,013	145,737
34	Total Production Expenses (total 23 thru 33)	2,782,086	3,527,927
35	Expenses per net KWh	0.0095	0.0113

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	04/15/2016	End of 2015/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
534	12	205	6
8,760	7,871	8,760	7
			8
747	15	221	9
220	1	202	10
8	2	6	11
1,719,268,000	31,539,000	750,079,000	12
			13
18,266,595	82,142	1,212,767	14
32,472,875	7,380,842	10,878,167	15
67,619,060	3,145,630	30,432,975	16
61,266,804	13,881,886	19,497,721	17
529,364	122,668	585,876	18
0	0	0	19
180,154,698	24,613,168	62,607,506	20
307.7463	1,981.7366	329.5132	21
			22
810,294	226,686	382,292	23
666,009	228,916	299,516	24
1,228,538	417,474	553,562	25
314,903	107,054	161,460	26
927,272	294,065	415,275	27
111,511	141	18,315	28
25,206	3,216	10,918	29
181,794	12,431	112,661	30
34,061	-9	5,274	31
748,067	64,559	147,767	32
428,623	100,709	341,148	33
5,476,278	1,455,242	2,448,188	34
0.0032	0.0461	0.0033	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	04/15/2016	End of 2015/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)	330	23
7	Plant Hours Connect to Load	8,760	8,760
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	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,461,432,000	154,194,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,376
15	Structures and Improvements	2,931,900	2,824,126
16	Reservoirs, Dams, and Waterways	52,872,923	6,283,406
17	Equipment Costs	19,960,871	12,088,094
18	Roads, Railroads, and Bridges	922,781	1,542,871
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,568,856	22,943,873
21	Cost per KW of Installed Capacity (line 20 / 5)	200.6867	1,053.9216
22	Production Expenses		
23	Operation Supervision and Engineering	472,143	196,895
24	Water for Power	425,145	849,855
25	Hydraulic Expenses	797,610	230,740
26	Electric Expenses	295,711	65,750
27	Misc Hydraulic Power Generation Expenses	575,747	177,704
28	Rents	30,450	0
29	Maintenance Supervision and Engineering	24,842	3,420
30	Maintenance of Structures	36,430	8,347
31	Maintenance of Reservoirs, Dams, and Waterways	244,249	22,262
32	Maintenance of Electric Plant	359,716	35,828
33	Maintenance of Misc Hydraulic Plant	688,719	147,409
34	Total Production Expenses (total 23 thru 33)	3,950,762	1,738,210
35	Expenses per net KWh	0.0027	0.0113

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	04/15/2016	End of 2015/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
87	22	37	6
8,760	8,747	7,157	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
375,982,000	110,847,000	76,114,000	12
			13
5,476,746	231,584	255,499	14
9,780,013	27,334,904	11,021,547	15
10,807,310	15,989,465	9,000,263	16
14,047,800	31,037,692	21,350,845	17
1,602,868	835,946	1,917,603	18
0	0	0	19
41,714,737	75,429,591	43,545,757	20
503.8012	3,017.1836	825.6685	21
			22
871,100	621,417	195,251	23
963,737	710,027	214,848	24
1,152,655	873,630	127,868	25
50,830	25,464	74,464	26
678,592	557,788	228,498	27
55,646	6,298	3,224	28
6,615	10,795	4,164	29
82,602	126,817	44,281	30
46,467	18,032	55,029	31
196,523	271,370	74,878	32
88,092	258,825	86,230	33
4,192,859	3,480,463	1,108,735	34
0.0112	0.0314	0.0146	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	04/15/2016	End of 2015/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)	36	13
7	Plant Hours Connect to Load	8,760	8,385
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	203,255,000	74,608,000
13	Cost of Plant		
14	Land and Land Rights	202,398	313,328
15	Structures and Improvements	2,080,266	1,253,635
16	Reservoirs, Dams, and Waterways	6,130,430	10,108,902
17	Equipment Costs	8,923,679	4,703,941
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,366,132	16,431,189
21	Cost per KW of Installed Capacity (line 20 / 5)	503.3661	1,314.4951
22	Production Expenses		
23	Operation Supervision and Engineering	281,120	150,239
24	Water for Power	281,812	161,587
25	Hydraulic Expenses	339,108	90,955
26	Electric Expenses	94,946	45,140
27	Misc Hydraulic Power Generation Expenses	241,563	183,335
28	Rents	0	88
29	Maintenance Supervision and Engineering	5,570	2,778
30	Maintenance of Structures	111,480	24,323
31	Maintenance of Reservoirs, Dams, and Waterways	36,230	987
32	Maintenance of Electric Plant	85,340	79,795
33	Maintenance of Misc Hydraulic Plant	115,278	68,595
34	Total Production Expenses (total 23 thru 33)	1,592,447	807,822
35	Expenses per net KWh	0.0078	0.0108

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	04/15/2016	End of 2015/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	34	38	6
0	8,758	5,827	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	207,416,000	70,756,000	12
			13
114,367	424,428	138,100	14
41,098,277	2,869,695	10,431,584	15
13,556,785	6,920,148	17,431,179	16
2,246,883	8,197,531	29,260,290	17
99,051	88,693	501,877	18
0	0	0	19
57,115,363	18,500,495	57,763,030	20
0.0000	308.3416	971.6237	21
			22
0	270,998	197,687	23
0	298,475	1,477,096	24
7,416,144	347,273	129,881	25
0	125,419	32,689	26
0	286,774	276,779	27
0	2,756	3,295	28
0	3,460	3,964	29
0	79,756	33,558	30
0	11,408	18,432	31
0	44,913	93,791	32
92,248	80,272	102,119	33
7,508,392	1,551,504	2,369,291	34
0.0000	0.0075	0.0335	35

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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	04/15/2016	2015/Q4

FOOTNOTE DATA

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	04/15/2016	End of 2015/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	2.3	15,695	3,583,449
3	Thousand Springs	1912	8.80	7.6	52,740	9,566,531
4						
5						
6	Internal Combustion:					
7	Salmon Diesel	1967	5.00	4.0	13	909,259
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9						
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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) 04/15/2016	Year/Period of Report End of 2015/Q4

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
1,433,380	238,000		70,444			2
1,087,106	259,879		84,574			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
						12
						13
						14
						15
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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	04/15/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 7 Column: a

Salmon units are classified as standby.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	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	0.41		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		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	19.85		1
11	Jim Bridger	Populus	345.00	345.00	S Tower	60.94		1
12	Populus	Kinport	345.00	345.00	S Tower	7.42		1
13	Jim Bridger	Populus	345.00	345.00	S Tower	61.09		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	46.27		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	Jim Bridger	Point of Rocks	230.00	230.00	H Wood			1
26	Brownlee	Ontario	230.00	230.00	S Tower	72.67		1
27	Mora	Bowmont	138.00	230.00	S P Wood	9.98		1
28	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
29	Jim Bridger	Point of Rocks	230.00	230.00	H Wood			1
30	Caldwell 710	Locust	230.00	230.00	SP Steel	18.60		1
31	Boise Bench	Caldwell	230.00	230.00	S Tower	7.73		1
32	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
33	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.78		2
34	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
35	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
36					TOTAL	4,769.03	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) 04/15/2016	Year/Period of Report End of 2015/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	15,974,858	16,231,239					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		603,657	603,657					3
1272 ACSR								4
3X1272 ACSR		17,991,882	17,991,882					5
3X1272 ACSR		16,358,594	16,358,594					6
								7
1272 ACSR	483,309	5,787,895	6,271,204					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		9,512,597	9,512,597					11
1272 ACSR								12
1272 ACSR		9,249,735	9,249,735					13
1272 ACSR								14
2X1272 ACSR		514,724	514,724					15
715.5 ACSR	283,143	8,543,370	8,826,513					16
715.5 ACSR	64,851	10,228,542	10,293,393					17
715.5 ACSR	51,448	224,222	275,670					18
								19
795 ACSR	62,218	5,685,245	5,747,463					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	1,080,441	1,099,270					24
1272 ACSR	1,190		1,190					25
2X954 ACSR	1,676,838	20,541,790	22,218,628					26
715.5 ACSR	413,793	2,209,007	2,622,800					27
715.5 ACSR								28
1272 ACSR	1,899		1,899					29
1590 ACSR	2,138,236	8,775,086	10,913,322					30
1272 ACSR	1,748,214	7,631,906	9,380,120					31
715.5 ACSR								32
1272 ACSR	3,062,812	6,560,901	9,623,713					33
795 AAC		89,680	89,680					34
954 ACSR	34,174	16,026,470	16,060,644					35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	36

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	Caldwell	Ontario	230.00	230.00	H Wood	30.10		1
2	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
3	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.43		1
4	Borah	Hunt	230.00	230.00	H Steel	68.17		1
5	Danskin	Hubbard	230.00	230.00	H Steel	36.30		1
6	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
7	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
8	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.39		1
9	Hemingway	Bowmont	230.00	230.00	SP Steel	13.01		1
10	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
11	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
12	Walla Walla	Hurricane	230.00	230.00	H Wood	31.66		1
13	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
14	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.68		1
15	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
16	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
17	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
18	Oxbow	Brownlee	230.00	230.00	S Tower	10.40		2
19	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
20	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.17		1
21	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.11		2
22	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
23	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
24	Brownlee	Boise Bench	230.00	230.00	S Tower	102.55		2
25	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
26	Palette Jct	Enterprise	230.00	230.00	H Wood	29.62		1
27	Borah	Brady #2	230.00	230.00	S Tower	0.46		1
28	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
29	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
30								
31	Goshen	State Line	161.00	161.00	H Wood	40.93		1
32	Don	Goshen	161.00	161.00	S Tower	2.37		2
33	Don	Goshen	161.00	161.00	H Wood	48.42		2
34	Antelope	Goshen	161.00	161.00	H Wood	5.67		1
35								
36					TOTAL	4,769.03	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.
2X954 ACSR	236,152	9,282,426	9,518,578					1
1272 ACSR								2
1272 ACSR	81,701	1,666,354	1,748,055					3
1590 ACSR	624,917	22,467,321	23,092,238					4
1590 ACSR		15,210,561	15,210,561					5
1590 ACSR								6
1590 ACSR								7
1590 ACSR		3,528,033	3,528,033					8
1590 ACSR	1,854,996	9,277,980	11,132,976					9
1590 ACSR	948,166	9,080,890	10,029,056					10
1272 ACSR								11
1272 ACSR		6,191,922	6,191,922					12
715.5 ACSR	385,287	9,806,478	10,191,765					13
715.5 ACSR								14
795 ACSR	53,068	3,447,479	3,500,547					15
795 ACSR								16
VARIOUS	289,934	8,966,987	9,256,921					17
1272 ACSR	14,810	1,237,524	1,252,334					18
715.5 ACSR	227,825	16,105,174	16,332,999					19
VARIOUS								20
1272 ACSR	87,468	3,902,140	3,989,608					21
1272 ACSR	171,081	1,674,451	1,845,532					22
1272 ACSR	44,687	1,252,130	1,296,817					23
954 ACSR	184,817	6,257,154	6,441,971					24
715.5 ACSR	247,857	5,849,559	6,097,416					25
1272 ACSR	84,014	1,904,234	1,988,248					26
1272 ACSR	3,068	541,820	544,888					27
715.5 ACSR								28
1272 ACSR	7,248	421,273	428,521					29
								30
250 COPPER	16,155	424,195	440,350					31
715.5 ACSR	88,204	2,312,904	2,401,108					32
397.5 ACSR								33
397.5 ACSR		784,659	784,659					34
								35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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	04/15/2016	End of 2015/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	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.22		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	1.15		2
4	Nampa	Caldwell	138.00	138.00	S P Wood	9.57		2
5	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.45		1
6	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
7	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
8	Brady	Fremont	138.00	138.00	S Tower	1.03		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	1.01		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	6.22		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	125.59		1
22	King	Wood River	138.00	138.00	H Wood	63.99		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	2.51		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	4,769.03	11.02	203

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	04/15/2016	End of 2015/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)	
250 COPPER	26,507	381,162	407,669					1
250 COPPER								2
715.5 ACSR	21,327	249,232	270,559					3
795 AAC	696,535	3,311,830	4,008,365					4
795 ACSR	84,229	4,258,619	4,342,848					5
795 ACSR	43,568	2,767,797	2,811,365					6
795 AAC	270,823	561,561	832,384					7
VARIOUS	564,932	4,137,263	4,702,195					8
VARIOUS								9
VARIOUS								10
VARIOUS	76,823	3,206,705	3,283,528					11
VARIOUS	55,521	2,811,621	2,867,142					12
397.5 ACSR	1,955	6,930	8,885					13
VARIOUS	34,428	5,464,961	5,499,389					14
715.5 ACSR	216,919	9,677,074	9,893,993					15
715.5 ACSR								16
715.5 ACSR								17
4\0	4,191	443,775	447,966					18
954 ACSR		96,921	96,921					19
250 COPPER	2,741	753,925	756,666					20
VARIOUS	28,490	3,221,596	3,250,086					21
VARIOUS	173,683	4,156,121	4,329,804					22
397.5 ACSR								23
VARIOUS	225,602	1,652,772	1,878,374					24
397.5 ACSR	92,173	2,463,550	2,555,723					25
VARIOUS	20	77,199	77,219					26
715.5 ACSR	3,123,380	8,853,560	11,976,940					27
VARIOUS								28
795AAC								29
1272 ACSR								30
250 COPPER	450	187,848	188,298					31
397.5 ACSR	349,712	7,115,557	7,465,269					32
397.5 ACSR								33
397.5 ACSR	141,534	2,679,939	2,821,473					34
397.5 ACSR								35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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	04/15/2016	End of 2015/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.
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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	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	13.50		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	1.69		1
8	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		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	6.65		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	0.43	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	4,769.03	11.02	203

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	04/15/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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	1,077,292	1,091,026					4
397.5 ACSR	18,223	1,281,344	1,299,567					5
VARIOUS	66,256	3,110,194	3,176,450					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	3,540,775	3,936,471					9
715.5 ACSR	343,955	2,138,853	2,482,808					10
795 ACSR								11
715.5 ACSR	14,697	811,164	825,861					12
795 AAC		50,319	50,319					13
795 AAC	489,037	2,165,954	2,654,991					14
1272 ACSR	935,810	3,503,157	4,438,967					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	18,884,762	21,358,595					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
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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	04/15/2016	End of 2015/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	68.20		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	167.03		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	408.70		1
34								
35	Total all lines					4,769.03	11.02	203
36					TOTAL	4,769.03	11.02	203

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	04/15/2016	End of 2015/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		11,121	11,121					1
250 COPPER		96,249	96,249					2
715.5 ACSR	1,174	225,641	226,815					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		4,177,555	4,177,555					10
250 COPPER	58	63,264	63,322					11
715.5 ACSR		76,560	76,560					12
397.5 ACSR		4,406	4,406					13
715.5 ACSR	1,074	622,115	623,189					14
397.5 ACSR	6,332	2,569,728	2,576,060					15
715.5 ACSR	86,651	2,516,180	2,602,831					16
715.5 ACSR								17
								18
715.5 ACSR	7	279,481	279,488					19
715.5 ACSR	5,620	1,366,840	1,372,460					20
715.5 ACSR	2,814	183,606	186,420					21
397.5 ACSR	17,818	261,512	279,330					22
								23
								24
								25
397.5 ACSR	1,978	63,404	65,382					26
								27
								28
VARIOUS	1,680,630	66,163,470	67,844,100					29
VARIOUS								30
								31
								32
VARIOUS	194,536	18,194,925	18,389,461					33
				8,044,636	3,092,363	3,084,849	14,221,848	34
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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.: 34 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.: 12 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.: 31 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 and Idaho Power owns 21.9% of this 25.8 mile line.

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.

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	04/15/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

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	Toponis	Pocket	9.80	S P Wood	17.76	1	1
2	NorthView Tap		6.17	S P Wood	16.70	1	1
3	Antelope	Scoville	0.12	H Wood	10.00	1	1
4	American Falls	Wheelon	1.05	H Wood	8.66	1	1
5							
6	Antelope	Goshen	5.67	H Wood	7.13	1	1
7							
8	Walla Walla	Hurricane	31.66	H Wood	4.84	1	1
9							
10	Goshen	Kinport	7.49	Latice	4.56	1	1
11							
12	Summer Lake	Hemingway	53.09	Latice	4.50	1	1
13	Hemingway	Midpoint	47.83	Latice	4.50	1	1
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		162.88		78.65	9	9

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	04/15/2016	End of 2015/Q4

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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
397	ACSR	TVS	138						1
715	ACSR	TVS-HL	138	138,062	2,021,538	2,017,955		4,177,555	2
397	ACSR	Horizonal	138		182	10,939		11,121	3
250	Copper	Horizonal	138		73,562	22,687		96,249	4
									5
397	ACSR	Horizonal	161		667,466	117,193		784,659	6
									7
1272	ACSR	Horizonal	230		4,384,658	1,807,264		6,191,922	8
									9
Double1272	ACSR	Delta	345		232,927	281,797		514,724	10
									11
Double1272	ACSR	Horizonal	500		10,989,610	7,002,272		17,991,882	12
Triple1273	ACSR	Horizonal	500		9,991,982	6,366,612		16,358,594	13
									14
									15
									16
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									42
									43
				138,062	28,361,925	17,626,719		46,126,706	44

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Schedule Page: 424 Line No.: 3 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

Schedule Page: 424 Line No.: 4 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

Schedule Page: 424 Line No.: 6 Column: b

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

Schedule Page: 424 Line No.: 8 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.

Schedule Page: 424 Line No.: 10 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.

Schedule Page: 424 Line No.: 12 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 424 Line No.: 13 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

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	04/15/2016	End of 2015/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	46.00	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	
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	13.00	
40	Burley Rural	distribution	69.00	13.00	

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	04/15/2016	End of 2015/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.
300	2					1
20	2					2
15	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
24	1					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
		4				33
721	5	1				34
18	1					35
24	1					36
20	1					37
6	1	1				38
10	1	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	04/15/2016	End of 2015/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	13.10	
12	Cascade	distribution	25.00		
13	Chestnut	distribution	138.00	13.00	
14	Clear Lake - attended	transmission	46.00	2.40	
15	Cliff	transmission	138.00	46.00	12.50
16	Cliff	transmission	138.00	46.00	12.95
17	Cloverdale	distribution	138.00	13.00	
18	Dale	distribution	46.00	4.60	
19	Dale	distribution	46.00	13.00	
20	Dale	distribution	69.00	13.00	
21	Dale	distribution	138.00	36.20	
22	Dale	transmission	138.00	46.00	12.47
23	Danskin- attended	transmission	230.00	18.00	
24	Danskin- attended	transmission	230.00	138.00	13.80
25	Danskin- attended	distribution	18.00	4.16	
26	Danskin- attended	transmission	138.00	12.00	
27	Danskin- attended	distribution	35.00	13.80	
28	Don	distribution	138.00	7.60	
29	Don	distribution	138.00	13.20	
30	Don	distribution	138.00	13.00	
31	Don	distribution	14.00		
32	DRAM	distribution	138.00	13.09	
33	DRAM	transmission	230.00	138.00	13.80
34	DRAM	distribution	138.00	12.47	
35	Duffin	distribution	138.00	35.00	
36	Eagle	distribution	138.00	13.09	
37	Eastgate	distribution	138.00		
38	Eastgate	distribution	138.00	13.00	
39	Eckert	distribution	138.00	36.20	
40	Eden	distribution	138.00	36.20	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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.
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
15	2					11
4	1					12
48	2					13
4	1					14
12	2	1				15
4	1					16
48	2					17
		1				18
		6				19
		1				20
27	1					21
25	1					22
140	1					23
180	1					24
6	1					25
96	2					26
5	1					27
		1				28
108	6	3				29
26	1	1				30
80	6					31
118	7					32
160	2					33
17	1					34
36	2					35
38	2					36
24	1					37
18	1					38
18	1					39
24	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	04/15/2016	End of 2015/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	Eden	transmission	138.00	46.00	12.98
2	Elkhorn	distribution	138.00	12.47	
3	Elkhorn	distribution	138.00	13.00	
4	Elmore	distribution	138.00	35.00	
5	Elmore	transmission	138.00	69.00	12.50
6	Elmore	transmission	138.00	69.00	12.98
7	Emmett	distribution	138.00		
8	Emmett	transmission	138.00	69.00	12.47
9	Falls	distribution	46.00	13.00	
10	Falls	distribution	46.00		
11	Filer	distribution	46.00	13.00	
12	Flat Top	distribution	46.00	13.00	
13	Flying H	distribution	69.00	2.40	
14	Fort Hall	distribution	46.00	13.00	
15	Fossil Gulch	distribution	138.00	35.00	
16	Fremont	transmission	138.00	46.00	12.50
17	Gary	distribution	138.00	13.09	
18	Gary	distribution	138.00	13.00	
19	Gem	distribution	69.00	13.00	
20	Gem	distribution	69.00		
21	Gooding Rural	distribution	46.00	13.00	
22	Golden Valley	distribution	69.00	13.00	
23	Goshen	transmission	345.00	161.00	
24	Gowen Substation	distribution	138.00	35.00	
25	Grindstone	distribution	35.00		
26	Grove	distribution	138.00	13.09	
27	Grove	distribution	138.00	13.00	
28	Hagerman	distribution	46.00	13.00	
29	Hagerman	distribution	69.00	13.00	
30	Hailey	distribution	138.00	13.00	
31	Happy Valley	distribution	138.00	13.09	
32	Haven	distribution	138.00	35.00	
33	Haven	transmission	138.00	46.00	
34	Hemingway	transmission	500.00	230.00	34.50
35	Hewlett Packard	distribution	138.00	13.00	
36	Hidden Springs	distribution	138.00	13.00	
37	Highland	distribution	138.00	13.00	
38	Hill	distribution	138.00	13.00	
39	Hillsdale	distribution	138.00		
40	Hoku	distribution	138.00	13.80	

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	04/15/2016	End of 2015/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.
15	1					1
8	1					2
8	1					3
17	1					4
15	1					5
15	1					6
24	1					7
25	1					8
8	1					9
10	1					10
10	1					11
13	2					12
15	2					13
10	1	1				14
15	1					15
50	3	1				16
20	1					17
17	1					18
8	1					19
10	1					20
15	2					21
10	1	1				22
896	2					23
24	1					24
5	2					25
48	2					26
24	1					27
10	1					28
5	1					29
20	1					30
18	1					31
12	1					32
25	1					33
600	3	1				34
20	1					35
8	1					36
18	1					37
39	2					38
24	1					39
		2				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	04/15/2016	End of 2015/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	Homedale	distribution	69.00	13.00	
2	Horse Flat	transmission	230.00	138.00	13.80
3	Horseshoe Bend	distribution	35.00		
4	Horseshoe Bend	distribution	69.00	36.20	
5	Horseshoe Bend	distribution	69.00	25.00	
6	Huston	distribution	69.00	13.00	
7	Hulen	distribution	46.00	13.00	
8	Hunt	transmission	230.00	138.00	13.80
9	Hydra	distribution	138.00	36.20	
10	Island	distribution	69.00	13.00	
11	Jefferson	transmission	161.00	161.00	
12	Jerome	distribution	138.00	13.00	
13	Jerome	distribution	138.00	13.09	
14	Julion Clawson	distribution	138.00	35.00	
15	Joplin	distribution	138.00	13.00	
16	Joplin	distribution	138.00	35.00	
17	Justice	transmission	230.00	138.00	13.80
18	Karcher	distribution	138.00	13.00	
19	Kenyon	distribution	69.00	13.00	
20	Ketchum	distribution	138.00	13.00	
21	Kimberly	distribution	138.00	13.00	
22	Kinport	transmission	161.00	46.00	13.20
23	Kinport	transmission	230.00	138.00	12.47
24	Kinport	transmission	230.00	138.00	13.80
25	Kinport	transmission	345.00	230.00	13.80
26	Kramer	distribution	138.00	35.00	
27	Kramer	distribution	138.00	36.20	
28	Kuna	distribution	138.00	13.00	
29	Lake	distribution	69.00	13.00	
30	Lake Fork	distribution	138.00	36.20	
31	Lake Fork	transmission	138.00	69.00	12.50
32	Lamb	distribution	138.00	13.00	
33	Langley Gulch- attended	transmission	230.00	138.00	13.80
34	Langley Gulch- attended	transmission	230.00		
35	Langley Gulch- attended	distribution		4.16	
36	Langley Gulch- attended	distribution	13.00	4.16	
37	Langley Gulch- attended	transmission	230.00	150.00	
38	Lansing	distribution	69.00	13.00	
39	Lincoln	distribution	138.00	13.09	
40	Linden	distribution	138.00	13.00	

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	04/15/2016	End of 2015/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)	
22	2					1
100	1					2
5	1					3
12	1					4
5	1					5
10	1					6
10	1					7
300	3					8
48	2					9
12	1					10
112	1					11
20	1					12
20	1					13
30	2					14
15	1					15
18	1					16
180	1					17
12	1					18
20	2					19
42	2					20
27	1	1				21
		7				22
180	1					23
180	1					24
600	3	1				25
12	1					26
18	1					27
15	1					28
10	1					29
18	1					30
15	1					31
18	1					32
180	1					33
246	2					34
12	1					35
12	1					36
		1				37
12	1					38
10	1					39
33	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Locust	distribution	138.00	36.20	
2	Locust	transmission	230.00	138.00	13.80
3	Lower Malad - attended	transmission	138.00	7.20	
4	Lower Salmon - attended	transmission	138.00	13.80	
5	Map Rock	distribution	69.00	13.00	
6	McCall	distribution	13.00	13.09	
7	McCall	distribution	138.00	36.20	
8	Meridian	distribution	138.00	13.00	
9	Micron	distribution	138.00	13.09	
10	Micron	distribution	138.00	13.00	
11	Midpoint	transmission	230.00	138.00	13.80
12	Midpoint	transmission	345.00	230.00	13.80
13	Midpoint	transmission	500.00	345.00	
14	Midrose	distribution	138.00	13.09	
15	Milner	transmission	138.00	69.00	12.47
16	Milner	distribution	69.00	46.00	6.90
17	Milner	distribution	138.00	35.00	
18	Milner PP - attended	transmission	138.00	13.80	
19	Moonstone	distribution	138.00	35.00	
20	Mora	distribution	138.00	35.00	
21	Mora	distribution	138.00	36.20	
22	Moreland	distribution	35.00	13.00	
23	Moreland	distribution	46.00	13.00	
24	Moreland	distribution	46.00	35.00	12.47
25	Mountain Home	distribution	69.00	13.00	
26	Mountain Home Air Force Base	distribution	69.00	13.00	
27	Mountain Home Air Force Base	distribution	138.00	13.00	
28	Nampa	transmission	230.00	138.00	13.80
29	Nampa	distribution	138.00	13.00	
30	New Meadows	distribution	138.00	36.20	
31	New Plymouth	distribution	69.00	13.00	
32	Notch Butte	distribution	138.00	13.09	
33	Orchard	distribution	69.00	36.20	
34	Orchard	distribution	69.00	35.00	12.47
35	Parma	distribution	69.00	13.00	
36	Parma	distribution	69.00	35.00	
37	Paul	distribution	138.00	35.00	
38	Payette	distribution	138.00	13.00	
39	Pingree	transmission	138.00	46.00	12.50
40	Pingree	distribution	138.00	35.00	

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	04/15/2016	End of 2015/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.
72	3					1
360	2					2
16	1					3
70	4					4
10	1					5
12	1					6
18	1					7
36	2					8
24	2					9
24	2					10
120	1					11
840	2	1				12
750	3					13
24	1					14
75	3	1				15
8	3	1				16
29	2					17
36	1					18
12	1					19
15	1					20
24	1					21
6	1					22
8	1					23
6	3	1				24
15	1					25
		1				26
18	1					27
180	1					28
50	3					29
12	1					30
10	1					31
10	1					32
6	1					33
10	3					34
10	1					35
12	1					36
36	2					37
23	3					38
50	3					39
22	2					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	04/15/2016	End of 2015/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	Pleasant Valley	distribution	138.00	35.00	
2	Pocatello	distribution	46.00	13.00	
3	Pocket	distribution	138.00	36.20	
4	Poleline	distribution	138.00	13.09	
5	**Populus**	transmission	345.00		
6	Portneuf	distribution	138.00	35.00	
7	Portneuf	distribution	46.00	35.00	
8	Rockford	distribution	46.00	13.00	
9	Russett	distribution	138.00	13.00	
10	Sailor Creek	distribution	138.00	2.40	
11	Sailor Creek	distribution	138.00	35.00	
12	Salmon	distribution	69.00	13.00	
13	Salmon	distribution	69.00	34.50	12.47
14	Salmon	distribution	69.00		12.47
15	Salmon	transmission	13.00	2.40	
16	Shoshone	distribution	46.00	13.00	
17	Shoshone	distribution	46.00	7.20	
18	Shoshone Falls - attended	transmission	46.00	2.30	
19	Shoshone Falls - attended	transmission	46.00	6.60	
20	Silver	distribution	138.00	35.00	
21	Simplot	distribution	138.00	13.00	
22	Sinker Creek	distribution	138.00	35.00	
23	Siphon	distribution	138.00	35.00	
24	South Park	distribution	46.00	13.00	
25	Star	distribution	138.00	13.09	
26	Starkey	transmission	138.00	69.00	12.47
27	State	distribution	69.00	13.00	
28	Stoddard	distribution	138.00	13.00	
29	Strike Power Plant - attended	transmission	138.00	13.80	
30	Sugar	distribution	138.00	35.00	
31	Swan Falls - attended	transmission	138.00	6.90	
32	Taber	distribution	46.00	13.00	
33	Ten Mile	distribution	138.00	13.09	
34	Terry	distribution	138.00	13.09	
35	Terry	distribution	138.00	13.00	
36	Thousand Springs - attended	transmission	46.00	7.20	
37	Thousand Springs - attended	transmission	7.00	2.40	
38	**Three Mile Knoll**	transmission	345.00		
39	Toponis	distribution	138.00	33.00	
40	Twin Falls	distribution	138.00	13.09	

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	04/15/2016	End of 2015/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.
42	2					1
36	2					2
24	1					3
18	1					4
						5
18	1					6
		1				7
14	2					8
18	1					9
15	2					10
15	1					11
10	1	3				12
10	3					13
		2				14
5	2					15
10	1					16
2	3					17
3	1					18
10	1					19
12	1					20
30	2					21
12	1					22
33	2					23
10	1					24
18	1					25
18	1					26
33	2					27
15	1					28
83	3					29
20	2					30
18	1					31
5	1					32
24	1					33
12	1					34
30	2					35
8	1					36
		1				37
						38
18	1					39
44	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Twin Falls	transmission	138.00	46.00	12.98
2	Twin Falls PP - attended	transmission	138.00	7.20	
3	Twin Falls PP - attended	transmission	138.00	13.20	
4	Upper Malad - attended	transmission	45.00	7.20	
5	Upper Salmon- attended	transmission	138.00	7.20	
6	Ustick	distribution	138.00	13.00	
7	Vallivue	distribution	138.00	13.09	
8	Victory	distribution	138.00	13.00	
9	Victory	distribution	138.00	13.09	
10	Ware	distribution	69.00	13.00	
11	Weiser	distribution	69.00	13.00	
12	Weiser	transmission	138.00	69.00	12.47
13	Wilder	distribution	69.00	13.00	
14	Willis	distribution	138.00	13.09	
15	Wye	distribution	138.00	13.00	
16	Wye	distribution	138.00	13.09	
17	Zilog	distribution	138.00	13.09	
18					
19					
20	The above are all State of Idaho				
21					
22	Montana:				
23	Peterson	transmission	230.00	69.00	13.20
24					
25	Nevada:				
26	Valmy - attended	transmission	345.00	125.00	24.90
27	Valmy - attended	transmission	345.00	125.00	24.90
28	Valmy - attended	transmission	120.00	24.90	7.20
29	Valmy - attended	transmission	345.00		
30	Valmy - attended	transmission	345.00		
31	Valmy - attended	transmission	345.00		
32	Valmy - attended	transmission	345.00		
33	Valmy - attended	transmission	345.00		
34	Wells	transmission	138.00	69.00	13.00
35					
36	Oregon:				
37	Boardman - attended	transmission	500.00	24.00	
38	Boardman - attended	transmission	230.00	7.20	
39	Boardman - attended	transmission	24.00	7.20	
40	Burns	transmission	500.00		

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	04/15/2016	End of 2015/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.
33	2					1
9	1					2
72	1					3
8	1					4
36	4					5
44	2					6
18	1					7
24	1					8
18	1					9
12	1	1				10
20	2					11
25	1					12
10	1					13
18	1					14
36	2					15
20	1					16
24	1					17
						18
						19
						20
						21
						22
24	3	1				23
						24
						25
	1					26
	1					27
	1					28
			Line Reactor	1	48	29
			Line Reactor	1	35	30
			Line Reactor	1	35	31
			Line Reactor	1	35	32
			Line Reactor	1	35	33
20	3	1				34
						35
						36
685	3					37
55	1					38
55	1					39
						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	04/15/2016	End of 2015/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	Cairo	distribution	69.00	13.00	
2	Hells Canyon - attended	transmission	230.00	13.80	
3	Hells Canyon - attended	distribution	69.00	0.50	
4	Hines	transmission	138.00	115.00	12.47
5	Hurricane	transmission	230.00		
6	Malheur Butte	distribution	69.00	34.50	
7	Nyssa	distribution	69.00	13.00	
8	Ontario	distribution	138.00	13.00	
9	Ontario	transmission	138.00	69.00	12.47
10	Ontario	transmission	230.00	138.00	13.80
11	Ontario	transmission	138.00	69.00	12.98
12	Ontario	transmission	138.00	69.00	13.09
13	Ore-Ida	distribution	69.00	13.00	
14	Oxbow - attended	transmission	138.00	69.00	13.00
15	Oxbow - attended	transmission	230.00	13.80	
16	Oxbow - attended	transmission	230.00	138.00	13.80
17	Quartz	transmission	138.00	69.00	12.50
18	Quartz	transmission	230.00	138.00	12.98
19	Quartz	transmission	138.00	69.00	12.98
20	Summer Lake	transmission	500.00		
21	Vale	distribution	69.00	13.00	
22					
23	Washington:				
24	Walla Walla	transmission	230.00		
25					
26	Wyoming:				
27	Jim Bridger - attended	transmission	345.00	22.00	34.50
28					
29					
30					
31					
32					
33	Transformers-distribution substations under 10,000				
34	KVA 83 unattended.				
35					
36					
37					
38					
39					
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	04/15/2016	End of 2015/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.
12	1					1
500	3	1				2
1	1					3
40	1					4
						5
8	3	1				6
20	2					7
38	2					8
25	1	1				9
240	2					10
50	2					11
		1				12
15	1					13
10	3	1				14
244	2					15
100	1					16
15	1					17
100	3	1				18
15	1					19
						20
10	1					21
						22
						23
						24
						25
						26
2244	4					27
						28
						29
						30
						31
						32
						33
329						34
						35
						36
						37
						38
						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.

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.

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.

Schedule Page: 426.2 Line No.: 23 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.

Schedule Page: 426.2 Line No.: 34 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.

Schedule Page: 426.3 Line No.: 11 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.: 25 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.

Schedule Page: 426.4 Line No.: 13 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.

Schedule Page: 426.5 Line No.: 5 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: 426.5 Line No.: 38 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.: 26 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 27 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 28 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 29 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

FOOTNOTE DATA

Schedule Page: 426.6 Line No.: 30 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 31 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 32 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 33 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 37 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 capacity is reported.

Schedule Page: 426.6 Line No.: 38 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 capacity is reported.

Schedule Page: 426.6 Line No.: 39 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 capacity is reported.

Schedule Page: 426.6 Line No.: 40 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.: 5 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.: 20 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.: 24 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.: 27 Column: a

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership.

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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	04/15/2016	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the 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	517,693
22			922000	60,452
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

Page Number	Title
1	Statement of Income for the Year
2	Taxes Allocated to Idaho
3	Notes and Accounts Receivable
3	Accumulated Provision for Uncollectible Accounts
4	Receivables from Associated Companies
5	Gain or Loss on Disposition of Property
6	Professional or Consultative Services
7-10	Electric Plant in Service
11	Electric Operating Revenues
12-15	Electric Operation and Maintenance Expenses
15	Number of Electric Department Employees

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STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122 for important notes regarding the state ment of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 1,208,201,834	$ 1,219,568,337
3	Operating Expenses			
4	Operation Expenses (401)	15	695,189,223	744,611,224
5	Maintenance Expenses (402)	15	65,984,911	64,952,478
6	Depreciation Expense (403)		125,382,354	120,300,338
7	Amort. & Depl. of Utility Plant (404-405)		6,708,360	6,687,969
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Accretion Expense (411)		221,919	296,254
11	Regulatory Study Costs (407)			
12	Amort. of Conversion Expenses (407)			
13	Regulatory Debits/Credits (407.3 & 407.4)		-	-
14	Taxes Other Than Income Taxes (408.1)	2	30,566,626	29,569,719
15	Income Taxes - Federal (409.1)	2	12,620,531	(7,055,229)
16	- Other (409.1)	2	5,825,567	6,624,230
17	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	27,032,456	17,355,209
18	Investment Tax Credit Adj. - Net (411.4)	2	471,511	39,767
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23				
24	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		970,003,458	983,381,958
25				
26				
27	Net Utility Operating Income (Enter Total of line 2 less 24)		$ 238,198,376	$ 236,186,379

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 13,981,739
FUTA	88,992
State Unemployment	582,363
Payroll Deduction & Loading	(14,653,094)
Total Labor Related	0
Property Taxes	26,310,700
Kilowatt-hour Tax	1,184,956
Licenses	4,788
Regulatory Commission Fees	2,842,553
Irrigation PIC	223,629
Canada Sales Tax	0
Total Taxes Other Than Income Taxes	30,566,626
Federal Income Taxes	12,620,531
State Income Taxes	5,825,567
Deferred Income Taxes	27,032,456
Investment Tax Credit Adjustment - Net	471,511
Total Taxes Allocated to Idaho	$ 76,516,691

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	$ -	
2	Customer Accounts Receivable (Account 142)	85,040,915	75,650,719
3	Other Accounts Receivable (Account 143)	14,677,441	23,486,155
4	(Disclose any capital stock subscription received)		
5	Total	$ 99,718,356	$ 99,136,874
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	4,650,829	1,355,042
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 95,067,527	$ 97,781,832
12			
13			
14			
15			
16			
17			
18			
19			
20			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21	Balance Beg of Year:	$ 4,650,829				$ 4,650,829
22						$ -
23	Uncollectible Retail Electric Sales	(751,888)	$	$		$ (751,888)
24						
25	Uncollectible Damage Claims	15,633				$ 15,633
26						
27	Uncollectibe Other Revenues	(2,559,532)				$ (2,559,532)
28						
29						
30						
31						
32	Balance end of year	$ 1,355,042	$ -	$ -	$ -	$ 1,355,042
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.
2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO	$ 2,053,198	$ 1,541,850	$ 2,438,845	$ 1,156,202	
4						
5						
6						
7						
8						
9						
10	Total Account 145	2,053,198	1,541,850	2,438,845	1,156,202	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc.		$ 7,479,664	$ 7,479,664	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ -	$ 7,479,664	$ 7,479,664	$ -	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.

2. Individual gains or losses relating to property with an original cost of less than $50,000 may be grouped, with the number of such transactions disclosed in column (a).

3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:	$		$	$
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14	Total gain..	$ 0		$ 0	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss..	$ 0			$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADECCO	Management Services	$ 19,016
2	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	243,477
3	AKIN GUMP STRAUSS HAUER & FELD	Legal Services	45,060
4	ALSTOM GRID INC	Power Grid Consulting	13,051
5	ANDERSON BANDUCCI PLLC	Legal Services	235,321
6	APPLIED ENERGY GROUP	Management Services	49,219
7	BAKER BOTTS LLP	Legal Services	40,481
8	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	375,658
9	BAYSWATER LLC	Legal Services	252,880
10	BETHKE LAW PLLC	Legal Services	18,950
11	BONNEVILLE BILLINGS & COL	Customer Billing Services	15,000
12	BROADRIDGE FINANCIAL SOLUTIONS	Management Services	47,433
13	BULLARD SMITH JERNSTEDT WILSON	Legal Services	16,768
14	BURR COMPUTER ENVIRONMENTS INC	IT Services	16,940
15	CAMACK CONSULTING INC	Employee Benefit Services	41,304
16	CASE FORENSICS CORPORATION	Management Services	25,969
17	CGI TECHNOLOGIES AND SOLUTIONS	IT Services	183,502
18	CLEAREDGE PARTNERS INC	Management Services	75,000
19	COMPUNET, INC	IT Services	47,506
20	CORPORATE OFFICE INSTALLATIONS	Management Services	370,555
21	DAVIS WRIGHT TREMAINE LLP	Legal Services	1,460,545
22	DELOITTE TAX LLP	Management Services	36,015
23	E SOURCE, INC.	Training Consultants	31,675
24	ERGO RISK MANAGEMENT GROUP INC	Training Consultants	131,753
25	EVANS KEANE	Legal Services	19,472
26	EVERGREEN CONSULTING GROUP, LL	Management Services	363,574
27	EVERGREEN ECONOMICS, INC.	Management Services	23,044
28	EXISTBI	Business Intelligence Support services	124,064
29	GIVENS PURSLEY LLP	Legal Services	143,192
30	H. W. LOCHNER, INC.	Enviromental Services	37,200
31	HAWLEY TROXELL ENNIS & HAWLEY	Legal Services	31,139
32	HONEYWELL INTERNATIONAL INC	Management Services	733,253
33	INDUSTRIAL HYGIENE RESOURCES,	Management Services	114,081
34	INTELLITECT	Management Services	132,682
35	ISS CORPORATE SERVICES, INC	Management Services	35,000
36	ITRON, INC.	Resource Management	220,882
37	J EVAN ROBERTSON PA	Legal Services	16,505
38	MAINLINE INFORMATION SYSTEMS I	Management Services	140,400
39	MAXISYS	Management Services	20,000
40	MCDOWELL RACKNER & GIBSON PC	Legal Services	710,141
41	MICROSOFT CORP	IT Services	12,220
42	MIRANDE, MICHAEL	Legal Services	28,573
43	MORROW & FISCHER PLLC	Legal Services	19,928
44	MOVESAFE INC	Training Consultants	207,111
45	NIELSEN GROUP INC	IT Services	161,580

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
46	OXFORD GLOBAL RESOURCES INC	Management Services	247,575
47	PAINE HAMBLEN LLP	Legal Services	57,201
48	PARR BROWN GEE & LOVELESS INC	Legal Services	15,668
49	PATRIOT ELECTRIC INC	Residential Construction Consulting	15,997
50	PERKINS COIE LLP	Legal Services	384,090
51	PRICEWATERHOUSE COOPERS LLP	Management Services	189,722
52	PROFESSIONAL TRAINING SYSTEMS	Training Consultants	11,221
53	REED HARRIS ENVIRONMENTAL LTD	Environmental Services	33,671
54	REGULIS INTEGRATED SOLUTIONS	Customer Billing Services	82,795
55	REX BLACK CONSULTING SERVICES	IT Services	27,969
56	RIGHT SYSTEMS, INC	IT Services	36,514
57	RM ENERGY CONSULTING	Management Services	326,647
58	SCHWABE WILLIAMSON & WYATT	Legal Services	23,566
59	SHL US INC	Talent Services	49,356
60	STOEL RIVES LLP	Legal Services	138,314
61	SULLIVAN & CROMWELL	Legal Services	135,810
62	TATA AMERICA INTERNATIONAL COR	Management Services	1,613,709
63	TELVENT USA LLC	Power Grid Consulting	14,616
64	TRINOOR LLC	HR Consulting	51,406
65	TUERI LLC	Management Services	140,655
66	UNIVERSITY OF IDAHO	Management Services	223,332
67	VAN NESS FELDMAN	Legal Services	448,994
68	WESTERN UNION FINANCIAL	Customer Billing Services	40,000
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	TOTAL		$ 11,395,945

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PROFESSIONAL OR CONSULTATIVE SERVICES

ITEMS $5,000 OR MORE BUT LESS THAN $10,000

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	CLEARESULT CONSULTING INC	Energy Efficiency Services	$ 8,500
2	CME, INC. OF IDAHO	General Electrical Contracting	7,925
3	ESKER, INC	IT Services	7,633
4	FORREST SERVICE	Environmental Services	5,000
5	FIRE CAUSE ANALYSIS	Fire Investigation Services	8,325
6	HIRST APPLEGATE LLP	Legal Services	6,023
7	JACO ENVIRONMENTAL INC	Environmental Services	8,709
8	MILLER & CHEVALIER CHARTERED	Legal Services	9,200
9	R R DONNELLEY	Electronic Filing Services	5,689
10	TOWERS WATSON PENNSYLVANIA	Energy Efficiency Services	8,900
11	VARIN WARDWELL LLC	Legal Services	8,218
12	WALDNER LAW OFFICES LLC	Legal Services	8,691
13	WILKINSON, BARKER, KNAUER LLP	Legal Services	5,100
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45	**TOTAL**		$ 97,912

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) . Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

Line No.	Account (a)	Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,459	
3	(302) Franchises and Consents	28,048,263	
4	(303) Miscellaneous Intangible Plant	28,362,313	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,416,036	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	6,611,529	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	956,598,850	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28			
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	731,577,803	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	End of Year (g)		Line No.
					1
			$ 5,464	(301)	2
			28,537,018	(302)	3
			27,301,694	(303)	4
			55,844,177		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			13,515,196	(317)	15
			1,057,561,298		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
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				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			748,923,070		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 530,535,722	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	2,218,712,375	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	34,605,711	
49	(352) Structures and Improvements	69,637,541	
50	(353) Station Equipment	382,718,777	
51	(354) Towers and Fixtures	161,019,362	
52	(355) Poles and Fixtures	136,488,285	
53	(356) Overhead Conductors and Devices	187,968,276	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	373,635	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	972,811,587	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,051,237	
61	(361) Structures and Improvements	32,116,160	
62	(362) Station Equipment	195,069,259	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	222,604,427	
65	(365) Overhead Conductors and Devices	119,358,951	
66	(366) Underground Conduit	46,631,228	
67	(367) Underground Conductors and Devices	215,537,454	
68	(368) Line Transformers	475,247,016	
69	(369) Services	55,003,907	
70	(370) Meters	77,835,697	
71	(371) Installations on Customer Premises	2,688,508	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,299,302	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,451,443,147	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	15,870,623	
78	(390) Structures and Improvements	102,467,445	
79	(391) Office Furniture and Equipment	43,942,561	
80	(392) Transportation Equipment	71,045,176	
81	(393) Stores Equipment	1,853,706	
82	(394) Tools, Shop, and Garage Equipment	7,251,311	
83	(395) Laboratory Equipment	12,112,184	
84	(396) Power Operated Equipment	13,342,917	
85	(397) Communication Equipment	51,491,365	
86	(398) Miscellaneous Equipment	5,338,964	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	324,716,252	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	324,716,252	
91	TOTAL (Accounts 101 and 106)	5,024,099,396	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 5,024,099,396	

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	44
			$ 516,333,612		45
			2,322,817,980		46
					47
			34,884,459	(350)	48
			74,584,045	(352)	49
			390,824,535	(353)	50
			177,042,687	(354)	51
			151,840,760	(355)	52
			203,174,425	(356)	53
				(357)	54
				(358)	55
			374,232	(359)	56
				(359.1)	57
			1,032,725,142		58
					59
			5,176,136	(360)	60
			32,644,394	(361)	61
			207,064,121	(362)	62
				(363)	63
			228,143,181	(364)	64
			120,527,316	(365)	65
			47,672,004	(366)	66
			227,020,812	(367)	67
			496,171,835	(368)	68
			55,899,072	(369)	69
			82,333,518	(370)	70
			2,729,762	(371)	71
				(372)	72
			4,333,517	(373)	73
				(374)	74
			1,509,715,668		75
					76
			15,884,981	(389)	77
			106,283,870	(390)	78
			44,738,612	(391)	79
			72,704,300	(392)	80
			2,161,043	(393)	81
			7,685,955	(394)	82
			12,172,325	(395)	83
			14,451,045	(396)	84
			53,096,779	(397)	85
			5,718,032	(398)	86
			334,896,942		87
				(399)	88
				(399.1)	89
			334,896,942		90
			5,255,999,909		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 5,255,999,909		96

ELECTRIC OPERATING REVENUES (Account 400)

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.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 494,611,468	$ 481,950,250
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	447,471,324	436,588,320
5	Large (or Industrial)(See Instr. 4) (2)	166,580,123	167,602,922
6	(444) Public Street and Highway Lighting	3,905,150	3,976,711
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,112,568,065 *	1,090,118,203
11	(447) Sales for Resale - Opportunity....Non-Firm Only	29,477,405	73,741,042
12	TOTAL Sales of Electricity	1,142,045,471	1,163,859,245
13	(449) Provision for Rate Refunds	(13,865,518)	(18,363,613)
14	TOTAL Revenue Net of Provision for Refunds	1,128,179,953	1,145,495,632
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,036,347	3,696,703
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,713,987	22,576,034
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	52,271,548	47,799,967
22			
23			
24			
25	TOTAL Other Operating Revenues	80,021,882	74,072,705
26	TOTAL Electric Operating Revenues	$ 1,208,201,834	$ 1,219,568,337

(1) Commercial and Industrial sales - Small - under 1,000 KW and includes all irrigation customers.
(2) Commercial and Industrial sales - Large - 1,000 KW and over.

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,803,995,275	4,784,072,514	418,906	411,689	2
				3
5,836,330,091	5,675,423,865	80,261	79,248	4
2,938,946,430	2,970,925,860	113	110	5
31,192,274	31,654,264	2,559	2,349	6
				7
				8
				9
13,610,464,070 **	13,462,076,503	501,839	493,396	10
1,196,890,694	1,609,051,066	N/A	N/A	11
14,807,354,764	15,071,127,569	501,839	493,396	12
				13

* Includes $7,438,098 unbilled revenues.

** Includes 95,904,770 KWH relating to unbilled revenues.

Lines 11 through 21 are on an "allocated" basis.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,234,974	$ 1,318,039
5	(501) Fuel	125,293,762	149,242,737
6	(502) Steam Expenses	9,344,671	8,353,412
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	1,204,563	1,528,536
10	(506) Miscellaneous Steam Power Expenses	6,401,977	9,189,663
11	(507) Rents	414,288	507,911
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	143,894,235	170,140,297
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	121,775	266,044
16	(511) Maintenance of Structures	841,997	678,123
17	(512) Maintenance of Boiler Plant	13,228,845	10,438,403
18	(513) Maintenance of Electric Plant	5,165,496	5,776,736
19	(514) Miscellaneous Steam Plant	6,638,813	5,558,967
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,996,925	22,718,272
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 2	169,891,160	192,858,570
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,558,396	5,456,838
45	(536) Water for Power	8,697,696	7,004,348
46	(537) Hydraulic Expenses	14,295,462	13,497,028
47	(538) Electric Expenses	1,555,246	1,464,659
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,442,169	5,488,290
49	(540) Rents	225,600	248,637
50	TOTAL Operation (Enter Total of lines 44 thru 49)	35,774,569	33,159,799

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 115,391	$ 116,975
54	(542) Maintenance of Structures	1,074,449	1,328,245
55	(543) Maintenance of Reservoirs, Dams, and Waterways	551,802	350,696
56	(544) Maintenance of Electric Plant	2,542,063	2,181,187
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,742,589	2,445,769
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,026,295	6,422,872
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and	42,800,863	39,582,671
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	620,066	779,191
63	(547) Fuel	52,436,682	43,069,104
64	(548) Generation Expenses	4,405,378	3,440,496
65	(549) Miscellaneous Other Power Generation Expenses	895,988	866,982
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	58,358,114	48,155,773
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	0
70	(552) Maintenance of Structures	348,753	361,955
71	(553) Maintenance of Generating and Electric Plant	68,784	82,752
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,218,031	1,332,131
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,635,568	1,776,838
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	59,993,681	49,932,611
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	207,677,199	226,605,619
77	(556) System Control and Load Dispatching	2,336	(1,189)
78	(557) Other Expenses	18,163,160	22,805,378
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	225,842,695	249,409,808
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79).	498,528,400	531,783,660
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,966,098	3,847,645
84	(561) Load Dispatching	2,817,822	2,579,291
85	(562) Station Expenses	2,524,933	2,353,313
86	(563) Overhead Line Expenses	927,497	640,645
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	5,992,521	5,811,469
89	(566) Miscellaneous Transmission Expenses	2,268	17,494
90	(567) Rents	2,957,854	3,144,575
91	TOTAL Operation (Enter Total of lines 83 thru 90)	19,188,991	18,394,430
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	150,586	162,267
94	(569) Maintenance of Structures	894,294	994,016
95	(570) Maintenance of Station Equipment	3,151,054	3,544,467
96	(571) Maintenance of Overhead Lines	2,814,416	3,061,759
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	0	1,525
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	7,010,350	7,764,033
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	26,199,341	26,158,464
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	4,102,960	3,856,280

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 3,750,022	$ 3,500,477
106	(582) Station Expenses	1,279,072	1,139,653
107	(583) Overhead Line Expenses	3,676,494	2,908,059
108	(584) Underground Line Expenses	2,850,198	2,489,099
109	(585) Street Lighting and Signal System Expenses	83,896	73,399
110	(586) Meter Expenses	4,606,198	4,276,734
111	(587) Customer Installations Expenses	724,519	640,974
112	(588) Miscellaneous Distribution Expenses	5,778,592	5,540,895
113	(589) Rents	250,686	446,160
114	TOTAL Operation (Enter Total of lines 103 thru 113)	27,102,636	24,871,729
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	10,165	15,747
117	(591) Maintenance of Structures	0	0
118	(592) Maintenance of Station Equipment	3,466,718	3,814,699
119	(593) Maintenance of Overhead Lines	13,159,994	12,883,895
120	(594) Maintenance of Underground Lines	596,266	621,410
121	(595) Maintenance of Line Transformers	35,220	142,325
122	(596) Maintenance of Street Lighting and Signal Systems	464,372	507,517
123	(597) Maintenance of Meters	741,737	710,855
124	(598) Maintenance of Miscellaneous Distribution Plant	267,593	386,170
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	18,742,066	19,082,617
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	45,844,703	43,954,347
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	466,780	481,778
130	(902) Meter Reading Expenses	1,764,385	1,492,534
131	(903) Customer Records and Collection Expenses	14,953,292	16,030,097
132	(904) Uncollectible Accounts	3,128,782	6,316,859
133	(905) Miscellaneous Customer Accounts Expenses	379	90
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	20,313,618	24,321,358
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	758,841	561,496
138	(908) Customer Assistance Expenses	35,331,512	32,298,865
139	(909) Informational and Instructional Expenses	409,488	361,011
140	(910) Miscellaneous Customer Service and Informational Expenses	691,250	658,759
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 14	37,191,091	33,880,131
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	76,081	
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	76,081	
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	69,806,988	69,850,602
152	(921) Office Supplies and Expenses	14,063,954	16,647,453
153	(Less) (922) Administrative Expenses Transferred-Credit	(24,956,472)	(26,023,220)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 7,813,431	$ 4,492,073
156	(924) Property Insurance	3,242,063	3,315,652
157	(925) Injuries and Damages	6,348,690	5,847,681
158	(926) Employee Pensions and Benefits	41,999,742	59,787,654
159	(927) Franchise Requirements	0	0
160	(928) Regulatory Commission Expenses	3,334,101	3,242,013
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	590,563	432,639
163	(930.2) Miscellaneous General Expenses	5,202,216	4,685,182
164	(931) Rents	1,916	168
165	TOTAL Operation (Enter Total of lines 151 thru 164)	127,447,192	142,277,897
166	Maintenance		
167	(935) Maintenance of General Plant	5,573,707	7,187,845
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	133,020,900	149,465,742
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 761,174,134	$ 809,563,702

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1	Payroll Period Ended (Date)	December 31, 2015	December 31, 2014
2	Total Regular Full-Time Employees	1,993	2,011
3	Total Part-Time and Temporary Employees	19	20
4	Total Employees	2,012	2,031