e-FILING REPORT COVER SHEET

REPORT NAME: 2013 FERC Form 1 Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

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

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

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

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

If Yes, enter docket number:

Key words:

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

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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

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

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 28, 2014

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
P. O. Box 2148
Salem, OR 97308-2148

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

Dear Sir or Madam:

As required by OAR 860-027-0070, Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report for the year ending December 31, 2013. Also included is the IDACORP 2013 Annual Report.

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

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

cc: RA Dept

THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____	

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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** 2013/Q4

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 2013/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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2761	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Ken Petersen	Ken Petersen	04/15/2014
02 Title Vice President, Controller & CAO		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[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) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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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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	Chief Executive Officer	J. LaMont Keen (1)	715,000
3			
4	President & Chief Executive Officer	Darrel T. Anderson (2)	500,000
5			
6	Executive Vice President & Chief Operating Officer	Dan Minor	410,000
7			
8	Senior Vice President & General Counsel	Rex Blackburn	320,000
9			
10	Senior Vice President, Power Supply	Lisa Grow	280,000
11			
12	Senior Vice President, CFO & Treasurer	Steven Keen (2)	280,000
13			
14	Vice President, Human Resources & Corporate Services	Luci McDonald	250,000
15			
16	Vice President & Chief Information Officer	Dennis Gribble (3)	230,000
17			
18	Vice President, Customer Operations	Warren Kline	240,000
19			
20	Vice President, & Chief Risk Officer	Lori Smith	225,000
21			
22	Vice President Delivery, Engineering & Construction	Vern Porter	220,000
23			
24	Vice President,Controller & Chief Accounting Officer	Ken Petersen (2)	205,000
25			
26	Vice President & Chief Information Officer	Lonnie Krawl (4)	200,000
27			
28	Vice President, Regulatory Affairs	Gregory Said	195,000
29			
30	Corporate Secretary	Patrick Harrington	176,000
31			
32	(1) Retired from position 12/31/2013		
33	(2) Appointed to position 1/1/2014		
34	(3) Retired 9/30/2013		
35	(4) Appointed to position 10/1/2013		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	1809 Headlee Lane, Lake Oswego, Oregon 97034
3		
4	Christine King***	8527 East old Field Rd
5		Scottsdale, Azizona 85266
6		
7	Gary Michael *** (5)	P.O. Box 1718, Boise, Idaho 83701
8		
9	Stephen Allred	4642 W Dawson Dr., Meridian, Idaho 83646
10		
11	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
12		
13	Darrel T. Anderson President & Chief Executive Office(1)	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	J. LaMont Keen, Chief Executive Officer** *** (2)	Idaho Power Company, 1221 W. Idaho Street,
17		P.O.Box 70, Boise, Idaho 83709-0070
18		
19	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
20		
21	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
22		
23	Thomas Wilford	1504 Warm Springs Avenue
24		Boise, Idaho 83712
25		
26	Richard Dahl ***	60 Laiki Pl.
27		Kailua, Hawaill 96734
28		
29	Dennis L. Johnson (3)	United Heritage Life Insurance
30		707 E. United Heritage Ct., Ste 130, Meridian, Idaho 83642
31		
32	Ronald W. Jibson (4)	Questar Corporation
33		333 South State Street, Salt Lake City, Utah 84145-0433
34		
35		
36	(1) Appointed to the board Sept 19, 2013; President and CEO	
37	as of 1/1/2014	
38	(2) Retired 12/31/13 from Idaho Power	
39	(3) Appointed 3/21/2013	
40	(4) Appointed 9/18/2013	
41	(5) Retired May 16, 2013	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

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

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

[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	20130829-5192	08/29/2013	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2013 Annual	
3				informational filing	
4				under ER09-1641-000	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	None			
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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. None

4. None

5. Reroute line into Pine creek substation due to failing structures.
   Line #447 Remove 1.51 miles of under-build to clean up feed to Notch Butte feed.
   Line #440 Added .71 miles as under-build on line 447 to facilitate the cleanup of Notch Butte feed.
   Line #412 .9 miles were added to the length of this line due to reroute around Emmett Gun Club.
   Line #202/404/465 Remove 1.13 miles of de-energized line 202, rebuild with new 138Kv line 465. 1.5 miles of line 404 was upgraded and the number changed to line 465. All work in and out of the nampa substation.
   Line #248 De-energized 6.9 miles of 69KV line between Nampa substation, Chestnut substation down to Lake Shore Drive.
   Line #205 Removed 2.8 miles of de-energized lien from Lansing substation down State street

6. On April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds, Series I, maturing on April 1, 2023, and $75 million in principal amount of 4.00% first mortgage bonds, Series I, maturing on April 1, 2043. On October 1, 2013, Idaho Power used a portion of the net proceeds of the April 2013 sale of first mortgage bonds to satisfy its obligations upon maturity of $70 million in principal amount of 4.25% first mortgage bonds. Issuance of the Series I first mortgage bonds in April 2013, combined with the issuance of $200 million in principal amount of Series I first mortgage bonds in August 2010 and $150 million in principal amount of Series I first mortgage bonds in April 2012, utilized in full the available amount under a registration statement Idaho Power filed with the U.S. Securities and Exchange Commission (SEC) in May 2010 and under a selling agency agreement executed with ten banks in June 2010.

7. None

8. Effective 1/05/2013 a 3.0% general wage adjustment was implemented.

9. See pages 123.20 to 123.21

10. None

11. None

12. None

13. Idaho Power has added Ron Jibson as a director effective 9/18/2013. There were also a number of changes for officers. LaMont Keen President and Chief Executive Officer of Idaho Power retired effective 12/31/2013. Darrel Anderson will succeed LaMont as President and Chief Executive Officer. Other changes on November 21, 2013 Steve Keen was promoted to Senior Vice President, CFO and Treasurer, Ken Petersen was promoted to Vice President, Controller and Chief Accounting Officer and Naomi Shankel was named Assistant Treasurer. Dennis Gribble Vice president and Chief Information Officer retired 9/30/2013, his successor is Lonnie Krawl.

14. Idaho Power and its unregulated parent, IDACORP have seperate cash management programs, (seperate 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) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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	5,087,492,230	4,922,872,974
3	Construction Work in Progress (107)	200-201	327,000,038	298,470,440
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,414,492,268	5,221,343,414
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,940,654,182	1,871,810,171
6	Net Utility Plant (Enter Total of line 4 less 5)		3,473,838,086	3,349,533,243
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)		3,473,838,086	3,349,533,243
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,274,121	1,462,166
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	91,384,572	84,680,243
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)		824	1,518
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		42,271,756	34,391,222
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		288,132	284,782
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		135,219,405	120,819,931
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		66,420,846	17,112,143
36	Special Deposits (132-134)		3,106,514	0
37	Working Fund (135)		14,100	39,100
38	Temporary Cash Investments (136)		100,000	100,000
39	Notes Receivable (141)		50,208	72,492
40	Customer Accounts Receivable (142)		100,221,798	67,661,588
41	Other Accounts Receivable (143)		11,336,452	20,876,001
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,501,686	1,872,855
43	Notes Receivable from Associated Companies (145)		0	1,008,249
44	Accounts Receivable from Assoc. Companies (146)		0	63,847
45	Fuel Stock (151)	227	41,546,323	42,388,239
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	49,267,705	47,455,954
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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	4,375,589	3,581,218
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)		15,204,045	12,688,220
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)		63,506,686	51,448,038
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		1,672,362	3,874,959
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		288,132	284,782
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)		354,032,810	266,212,411
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,183,115	17,143,425
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	1,036,375,119	1,141,110,726
73	Prelim. Survey and Investigation Charges (Electric) (183)		883,871	819,409
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)		2,147,654	1,364,037
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	45,208,766	53,913,850
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)		13,860,473	14,921,058
82	Accumulated Deferred Income Taxes (190)	234	246,774,821	316,262,777
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,362,433,819	1,545,535,282
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,325,524,120	5,282,100,867

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	end of 2013/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	843,625,028	752,514,607
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	88,921,479	82,217,150
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)	-16,553,375	-17,115,669
16	Total Proprietary Capital (lines 2 through 15)		1,724,030,672	1,625,653,628
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,595,460,000	1,515,460,000
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	24,139,545	25,203,182
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,277,591	2,967,860
24	Total Long-Term Debt (lines 18 through 23)		1,616,321,954	1,537,695,322
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)		1,670,695	5,479,272
29	Accumulated Provision for Pensions and Benefits (228.3)		245,780,272	425,887,098
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,771,356	2,261,891
31	Accumulated Provision for Rate Refunds (229)		59,388,816	45,672,853
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)		25,765,364	22,982,049
35	Total Other Noncurrent Liabilities (lines 26 through 34)		335,376,503	502,283,163
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		105,671,106	108,223,362
39	Notes Payable to Associated Companies (233)		13,264,181	0
40	Accounts Payable to Associated Companies (234)		1,158,063	252,507
41	Customer Deposits (235)		1,428,221	1,966,205
42	Taxes Accrued (236)	262-263	15,104,410	8,109,787
43	Interest Accrued (237)		22,834,804	22,441,369
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) [ ] An Original (2) [X] A Resubmission	04/15/2014	end of 2013/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)		1,444,649	1,905,279
48	Miscellaneous Current and Accrued Liabilities (242)		35,788,243	30,534,183
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		571,747	1,054,644
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)		197,265,424	174,487,336
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		9,465,217	13,261,592
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,121,290	79,896,604
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	12,386,721	17,982,872
60	Other Regulatory Liabilities (254)	278	70,377,000	69,401,786
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)		1,143,090,466	1,080,279,413
64	Accum. Deferred Income Taxes-Other (283)		138,088,873	181,159,151
65	Total Deferred Credits (lines 56 through 64)		1,452,529,567	1,441,981,418
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,325,524,120	5,282,100,867

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	1,242,150,868	1,075,085,871		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	710,931,086	596,383,061		
5	Maintenance Expenses (402)	320-323	67,728,722	74,129,496		
6	Depreciation Expense (403)	336-337	121,486,191	116,113,891		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	587,012	317,075		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,611,634	7,483,540		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337		-13,255		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		56,176	39,784		
13	(Less) Regulatory Credits (407.4)			788,738		
14	Taxes Other Than Income Taxes (408.1)	262-263	30,560,823	30,488,808		
15	Income Taxes - Federal (409.1)	262-263	9,918,700	-14,482,226		
16	- Other (409.1)	262-263	5,499,764	1,007,613		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	138,292,290	239,208,729		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	82,501,409	200,111,787		
19	Investment Tax Credit Adj. - Net (411.4)	266	-775,313	9,056,202		
20	(Less) Gains from Disp. of Utility Plant (411.6)		6,043			
21	Losses from Disp. of Utility Plant (411.7)		6,766			
22	(Less) Gains from Disposition of Allowances (411.8)		41,307	201,565		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		322,348	183,144		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,009,677,440	858,813,772		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		232,473,428	216,272,099		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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
1,242,150,868	1,075,085,871					2
						3
710,931,086	596,383,061					4
67,728,722	74,129,496					5
121,486,191	116,113,891					6
587,012	317,075					7
7,611,634	7,483,540					8
	-13,255					9
						10
						11
56,176	39,784					12
	788,738					13
30,560,823	30,488,808					14
9,918,700	-14,482,226					15
5,499,764	1,007,613					16
138,292,290	239,208,729					17
82,501,409	200,111,787					18
-775,313	9,056,202					19
6,043						20
6,766						21
41,307	201,565					22
						23
322,348	183,144					24
1,009,677,440	858,813,772					25
232,473,428	216,272,099					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)		232,473,428	216,272,099		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		946,897	1,639,354		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,079,771	1,634,620		
33	Revenues From Nonutility Operations (417)		41,993	46,890		
34	(Less) Expenses of Nonutility Operations (417.1)		60,482	276,349		
35	Nonoperating Rental Income (418)		-2,844	-16,185		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,704,329	6,150,725		
37	Interest and Dividend Income (419)		2,426,000	2,018,711		
38	Allowance for Other Funds Used During Construction (419.1)		14,857,580	22,433,417		
39	Miscellaneous Nonoperating Income (421)		14,488,869	1,990,234		
40	Gain on Disposition of Property (421.1)		-2,442			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		38,320,129	32,352,177		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,917			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		744,976	717,897		
46	Life Insurance (426.2)		-18,319	-14,029		
47	Penalties (426.3)		428,042	-560,608		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,282,131	1,256,347		
49	Other Deductions (426.5)		8,655,953	7,533,768		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,094,700	8,933,375		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	22,991	24,640		
53	Income Taxes-Federal (409.2)	262-263	1,540,870	-102,078		
54	Income Taxes-Other (409.2)	262-263	417,095	-161,217		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	2,496,132	652,958		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,173,220	2,320,966		
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)		2,303,868	-1,906,663		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		24,921,561	25,325,465		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		81,492,149	78,922,057		
63	Amort. of Debt Disc. and Expense (428)		1,609,364	1,570,010		
64	Amortization of Loss on Reaquired Debt (428.1)		1,060,585	1,008,756		
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)		7,955			
68	Other Interest Expense (431)		4,146,983	3,858,107		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,663,190	11,929,405		
70	Net Interest Charges (Total of lines 62 thru 69)		80,653,846	73,429,525		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		176,741,143	168,168,039		
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)		176,741,143	168,168,039		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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		749,111,203	657,027,573
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)		170,036,814	162,017,314
17	Appropriations of Retained Earnings (Acct. 436)			
18		215.1	-3,256,123	(1,193,716)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-3,256,123	(1,193,716)
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			-78,926,392	(68,739,968)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-78,926,392	(68,739,968)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		836,965,502	749,111,203
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)
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)		6,659,526	3,403,404
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		6,659,526	3,403,404
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		843,625,028	752,514,607
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		82,217,150	76,066,425
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,704,329	6,150,725
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		88,921,479	82,217,150

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	176,741,143	168,168,039
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	121,486,191	116,113,891
5	Amortization of Note 1	11,648,544	12,211,778
6			
7			
8	Deferred Income Taxes (Net)	55,836,153	40,671,950
9	Investment Tax Credit Adjustment (Net)	-497,674	5,813,188
10	Net (Increase) Decrease in Receivables	-30,953,272	-1,457,986
11	Net (Increase) Decrease in Inventory	-1,213,152	930,136
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	7,503,331	12,717,237
14	Net (Increase) Decrease in Other Regulatory Assets	-40,694,556	-42,236,101
15	Net Increase (Decrease) in Other Regulatory Liabilities	15,112,871	-11,230,901
16	(Less) Allowance for Other Funds Used During Construction	14,857,580	22,433,417
17	(Less) Undistributed Earnings from Subsidiary Companies	6,704,329	6,150,724
18	Other (provide details in footnote): Note 2	-17,772,390	-31,590,882
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	275,635,280	241,526,208
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-250,164,015	-227,831,534
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	-14,857,580	11,929,405
31	Other (provide details in footnote): Note 3	498,473	2,738,701
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-234,807,962	-237,022,238
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		
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)	-32,660,820	-7,000,000
45	Proceeds from Sales of Investment Securities (a)	25,660,820	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	22,284	22,284
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): Note 4	17,722,855	16,672,022
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-224,062,823	-227,327,932
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	150,000,000
62	Preferred Stock		
63	Common Stock		7,500,000
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)	150,000,000	157,500,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-71,063,636	-101,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,298,726	-3,959,067
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-78,926,392	-68,739,968
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-2,288,754	-16,262,671
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	49,283,703	-2,064,395
87			
88	Cash and Cash Equivalents at Beginning of Period	17,251,243	19,315,638
89			
90	Cash and Cash Equivalents at End of period	66,534,946	17,251,243

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

Amortization	Twelve Months Ended 12/31/13
Plant	7,611,634
Unamortized debt expense	2,708,720
Unamortized discount	258,770
Water rights	1,042,009
Other	27,411
	11,648,544

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

Cash paid during the period for:	
Income taxes	9,031,086
Interest (net of amount capitalized)	77,582,508

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

Cash Flow from Operating Activities (Other)	Twelve Months Ended 12/31/13
Pension and postretirement benefit plan expense	45,860,740
Contributions to pension and postretirement benefit plans	(33,346,747)
Unbilled revenues	(12,058,648)
Gain on sale of investments and assets	(11,678,459)
Customer deposits	(3,658,360)
Accrued Interest	393,435
Other	(3,284,351)
	(17,772,390)

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	24,246,216

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

Other Cash Flows from Plant	Twelve Months Ended 12/31/13
Sale of emission allowances and renewable energy certificates	498,473
	498,473

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

Other Investing Cash Flows	Twelve Months Ended 12/31/13
Disbursements from rabbi trust	3,514,193
Net change in notes receivable from subsidiary	14,272,430
Miscellaneous other investing activities	(63,768)
	17,722,855

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) __ An Original (2) X A Resubmission	04/15/2014	2013/Q4

FOOTNOTE DATA

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power Company (Idaho Power) is the principal operating subsidiary of IDACORP Inc. (IDACORP), a holding company formed in 1998. Idaho Power is an electric utility 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 and (7) accrued taxes.

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

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 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 through a charge to the allowance and a credit to accounts receivable.

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

There were no impaired receivables without related allowances at December 31, 2013 and 2012. 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. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead recorded 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 2.69 percent in 2013 and 2.75 percent in 2012.

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. If any costs are expensed, 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 must be recognized in the financial statements. There were no material impairments of these assets in 2013 or 2012.

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 Hells Canyon Complex 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 rates for 2013 and 2012 were 7.7 percent for both years.

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 are being amortized over the terms of the respective debt issues.

2. INCOME TAXES

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

	2013	2012
	(thousands of dollars)	
Federal income tax expense at 35% statutory rate	$ 87,310	$ 70,320
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,347)	(2,153)
AFUDC	(7,882)	(12,027)
Capitalized interest	1,832	5,075
Investment tax credits	(3,120)	(3,267)
Removal costs	(3,527)	(2,697)
Capitalized overhead costs	(8,750)	(8,750)
Capitalized repair costs	(19,250)	(19,250)
Tax method change – capitalized repairs	4,583	(7,845)
State income taxes, net of federal benefit	6,970	7,646
Depreciation	14,820	14,398
Other, net	2,076	(8,703)
Total income tax expense (benefit)	$ 72,715	$ 32,747
Effective tax rate	29.1%	16.3%

The items comprising income tax (benefit) expense are as follows:

	2013	2012
	(thousands of dollars)	
Income taxes current:		
Federal	$ 11,460	$ (14,584)
State	5,917	846
Total	17,377	(13,738)
Income taxes deferred:		
Federal	56,918	47,069
State	(804)	(9,640)
Total	56,114	37,429
Uncertain tax positions:		
Federal	—	—
State	—	—
Total	—	—
Investment tax credits:		
Deferred	2,344	12,323
Restored	(3,120)	(3,267)
Total	(776)	9,056
Total income tax expense (benefit)	$ 72,715	$ 32,747

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

	Idaho Power	
	2013	2012
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 55,017	$ 55,085
Deferred compensation	23,647	23,463
Advanced payments	23,062	17,856
Tax credits	23,642	21,174
Net operating losses	29,628	47,351
Retirement benefits	69,033	146,546
Other	10,359	10,146
Total	234,388	321,621
Deferred tax liabilities:		
Property, plant and equipment	436,837	406,283
Regulatory assets	710,482	677,795
Power cost adjustments	35,763	16,832
Fixed cost adjustment	7,634	5,246
Retirement benefits	65,810	142,270
Other	12,267	18,371
Total	1,268,793	1,266,797
Net deferred tax liabilities	$ 1,034,405	$ 945,176

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

A reconciliation of the beginning and ending amount of unrecognized tax benefits for Idaho Power is as follows (in thousands of dollars):

	2013	2012
Balance at January 1,	$ —	$ —
Additions for tax positions of the current year	—	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	—
Settlements with taxing authorities	—	—
Balance at December 31,	$ —	$ —

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Idaho Power recognized no interest expense or penalties in 2013 or 2012, and there were no accrued interest or penalties as of December 31 for the same years.

Idaho Power is subject to examination by its major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2013 for federal and 2010-2013 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 2013, the IRS completed its examination of IDACORP's 2012 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2013 and prior tax years.

Tax Accounting Method Changes for Repair-Related Expenditures

In June 2010, Idaho Power completed its evaluation of a tax accounting method change for its 2009 tax year that allows a current income tax deduction for repair-related expenditures on its utility assets that are currently capitalized for financial reporting and tax purposes. In September 2010, Idaho Power adopted this method following the automatic consent procedures with the filing of IDACORP's 2009 consolidated federal income tax return. The method was subject to audit under IDACORP's 2009 CAP examination.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 CAP examination and submitted its report on the 2009 tax year to the U.S. Congress Joint Committee on Taxation (Joint Committee) for review. The capitalized repairs method is effectively settled and no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

On September 13, 2013, the U.S. Treasury Department and U.S. Internal Revenue Service (IRS) issued final regulations addressing the deduction or capitalization of expenditures related to tangible property. The regulations are generally effective for taxable years beginning on or after January 1, 2014.

In connection with the issuance of the regulations, Idaho Power assessed and estimated the impact of a method change associated with the electric generation property portion of the capitalized repairs method it adopted in fiscal year 2010. The change will be made pursuant to Revenue Procedure 2013-24 to bring Idaho Power’s existing method into alignment with the Revenue Procedure’s safe harbor unit-of-property definitions for electric generation property. Given Idaho Power’s intent to make this method change for generation property, in the third quarter of 2013 it recorded $4.6 million of income tax expense related to the estimated taxable income for the cumulative method change adjustment for years prior to 2013. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power will be permitted to adopt this method in either its 2013 or 2014 tax years with the filing of IDACORP’s consolidated federal income tax return. The method change will be subject to IRS review as part of IDACORP’s CAP examination.

In the third quarter of 2012, Idaho Power completed an income tax accounting method change for its 2011 tax year associated with the electric transmission and distribution property portion (as opposed to the generation property portion described above) of the capitalized repairs method it adopted in fiscal year 2010. As a result of the change, in 2012 Idaho Power recorded a $7.8 million tax benefit related to the filed deduction for the cumulative method change adjustment for years prior to 2011. The change was made pursuant to Revenue Procedure 2011-43 to bring Idaho Power’s existing method into alignment with the Revenue Procedure’s safe harbor unit-of-property definitions for electric transmission and distribution property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP’s 2011 consolidated federal income tax return. The IRS approved the method change prior to the filing of the return as part of IDACORP’s 2011 CAP examination. The final tangible property regulations discussed above are not expected to materially impact this tax accounting method.

Idaho Power’s prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type. A net regulatory asset is established to reflect Idaho Power’s ability to recover the net increased income tax expense when such temporary differences reverse. Idaho Power’s 2013 capitalized repairs deduction estimate incorporates the provisions of both method changes.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. The uniform capitalization method is effectively settled and no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $59.7 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

3. REGULATORY MATTERS

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.

Regulatory Assets and Liabilities

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, except for the cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power’s regulatory assets and liabilities (in thousands of dollars):

As of December 31, 2013

Description	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Total as of December 31, 2013	2012
Regulatory Assets					
Income Taxes		$ -	$ 710,482	$ 710,482	$ 677,795
Unfunded postretirement benefits(2)		-	116,583	116,583	308,850
Pension expense deferrals(3)		45,521	29,587	75,108	64,995
Energy efficiency program costs(3)		3,694	-	3,694	17,085
Power supply costs(3)	Varies	91,477	-	91,477	60,680
Fixed cost adjustment(3)	2014-2015	19,526	-	19,526	13,418
Asset retirement obligations(4)		-	18,026	18,026	15,411
Mark-to-market liabilities(5)		-	1,629	1,629	1,055
Other	2014-2021	1,992	1,554	3,546	3,749
Total		$ 162,210	$ 877,861	$ 1,040,071	$ 1,163,038
Regulatory Liabilities					
Income taxes		$ -	$ 55,017	$ 55,017	$ 55,085
Investment tax credits		-	79,121	79,121	79,897
Deferred revenue-AFUDC(6)		38,508	20,483	58,991	45,673
Energy efficiency program costs(3)		6,686	-	6,686	4,130
Power supply costs(3)	Varies	24	-	24	17,778
Settlement agreement sharing mechanism(3)	2014-2015	7,602	-	7,602	7,151
Mark-to-market assets(5)		-	1,672	1,672	4,579
Other		2,493	977	3,470	2,695
Total		$ 55,313	$ 152,270	$ 212,583	$ 216,988

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

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

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

(6) As part of its January 30, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the HCC relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power has collected revenue in the Idaho jurisdiction for these relicensing costs, but is deferring revenue recognition of the amounts collected until the license is issued and the asset is placed in service under the new license.

Idaho Power's regulatory assets and liabilities are 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 and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, fuel prices, changes in contracted power purchase prices and volumes (including PURPA power purchases), and the levels of Idaho Power's own hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments consist of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to 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 load change adjustment rate, which is intended to ensure that power supply expense fluctuations resulting solely from load changes do not distort the results of the mechanism.

The table below summarizes the three most recent Idaho PCA rate adjustments.

Effective	$ Change (millions)	Notes
June 1, 2013	$ 140.4	The 2013 Idaho PCA rates are offset by $7.2 million of Idaho revenue-sharing related to 2012 financial results pursuant to an IPUC order issued in 2012 under regulatory settlement agreements approved in January 2010 and December 2011. The $140.4 million increase in PCA rates includes the $19.9 million reduction in the revenue sharing amount (described below) from $27.1 million for the 2012-2013 PCA to $7.2 million for the 2013-2014 PCA.
June 1, 2012	$ 43.0	The PCA rate increase was offset by $27.1 million to be shared with customers pursuant to the revenue sharing order described below, resulting in a net rate increase of $15.9 million for these orders.

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 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 2013 and 2012 are summarized in the table that follows.

Year and Mechanism	APCU or PCAM Adjustment
2013 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.

2013 APCU	A rate increase of $2.9 million annually took effect June 1, 2013.
2012 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2012 APCU	A rate increase of $1.8 million annually took effect June 1, 2012.

Idaho Regulatory Matters

2011 Idaho General Rate Case Settlement: On June 1, 2011, Idaho Power filed a general rate case with the IPUC requesting approximately $82.6 million in additional Idaho jurisdiction annual revenues for collection through base rates. On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. The settlement stipulation, approved by the IPUC in December 2011, provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues, effective January 1, 2012. Neither the settlement stipulation nor the associated IPUC order specified an authorized rate of return on equity or imposed a moratorium on Idaho Power's filing a general rate case at a future date.

Idaho Power's Idaho jurisdiction base rates were again reset effective in July 2012, following completion of the Langley Gulch power plant, as described below.

January 2010 Idaho Settlement Agreement: In January 2010, the IPUC approved a settlement agreement among Idaho Power, the IPUC Staff, several of Idaho Power’s customers, and other interested parties. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in the 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on year-end equity in the Idaho jurisdiction (Idaho ROE) in any calendar year from 2009 through 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 through 2011.

Because Idaho Power’s actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and recorded an associated regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdiction earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

December 2011 Idaho Settlement Agreement: The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement agreement extending, with modifications, some of the provisions of the January 2010 settlement agreement. The settlement agreement provided that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional 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 exceeds 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 adjustment; and

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 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.

The December 2011 settlement agreement provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. In consideration for the authority to amortize additional ADITC described above, the December 2011 settlement agreement provided that Idaho Power would allocate to customers as a reduction to the pension regulatory asset 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE.

Revenue Sharing Under December 2011 Idaho Settlement Agreement: The amounts Idaho Power recorded in 2012 and 2013 for revenue sharing under the December 2011 Idaho regulatory settlement described above were as follows (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense
2013	$7.6	$16.5
2012	$7.2	$14.6

Cost Recovery for Langley Gulch Power Plant: On March 2, 2012, Idaho Power filed an application with the IPUC requesting an increase in annual Idaho-jurisdiction base rates of $59.9 million for recovery of Idaho Power's investment and associated costs for the Langley Gulch natural gas-fired power plant, which became commercially available in June 2012. Idaho Power's application stated that its estimated investment in the plant through June 2012 was approximately $398 million. After the impact of depreciation, deferred income taxes, amounts currently included in rates, and an Idaho-jurisdictional cost allocation, Idaho Power's application requested a $336.7 million increase in Idaho-jurisdiction rate base. Idaho Power's requested base rate increase was based on an overall rate of return of 7.86 percent, as authorized by a prior IPUC order. On June 29, 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.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power has made substantial contributions to its defined benefit pension plan in recent years. Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2013, Idaho Power's deferral balance associated with the Idaho jurisdiction was $72.6 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. In light of the substantial prior and expected future contributions, in March 2011 Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-jurisdiction portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective on June 1, 2011.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) is designed to remove Idaho Power’s 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 is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The amount of 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)(1)
2012	June 1, 2013-May 31, 2014	$8.9

2011	June 1, 2012-May 31, 2013	$10.3
2010	June 1, 2011-May 31, 2012	$9.3

(1) The amount shown represents the total FCA deferred amount. The amount of the change in the FCA amount for a year is calculated as the difference between the subject year's annual FCA amount and the prior year's FCA amount.

The deferral for the 2013 FCA was $15.4 million which, pending approval by the IPUC, will be recovered between June 1, 2014 and May 31, 2015.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. In the 2012 PCA filing, $14.7 million of certain demand response program costs were shifted from the rider mechanism to the PCA mechanism, as these costs are closely related to and directly impact the other power supply costs collected through the PCA. The December 2011 IPUC general rate case settlement order described above reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

On April 3, 2013, Idaho Power filed an application with the IPUC requesting an order finding Idaho Power's 2012 expenditures of $25.9 million in energy efficiency rider funds, $6.0 million in custom efficiency program incentives in a regulatory asset account, and $14.5 million of demand response program incentives included in the 2013 PCA, as prudently incurred demand-side management program expenses. On December 20, 2013, the IPUC issued an order finding all but $0.3 million of such expenses as prudently incurred, though the IPUC's order does provide Idaho Power with an opportunity to re-present $0.2 million of that amount for subsequent reconsideration. A previous order of the IPUC approved as prudently incurred $42.5 million of 2011 expenditures. As of December 31, 2013, the Idaho energy efficiency rider balance was a regulatory liability of $6.7 million. Separately, on June 12, 2013, the IPUC issued an order authorizing Idaho Power to recover custom efficiency program incentive payments, including the then-current regulatory account balance of $14.3 million, as well as subsequent custom efficiency program incentive payments, through the Idaho energy efficiency rider mechanism. As a result of the order, Idaho Power recognized the balance as other revenue and energy efficiency program expenses in 2013.

Certificate of Public Convenience and Necessity for Jim Bridger Plant Upgrades: On June 28, 2013, Idaho Power filed an application with the IPUC requesting that the IPUC issue a Certificate of Public Convenience and Necessity (CPCN) related to selective catalytic reduction (SCR) investments planned for Jim Bridger coal-fired plant units 3 and 4. Idaho Power's CPCN application requested that the IPUC provide Idaho Power with authorization and a binding commitment to provide rate base treatment for Idaho Power's share of the SCR investment in the amount of approximately $130 million (including AFUDC). Filing of the CPCN was intended to allow the IPUC to review the prudence of the investment in SCR prior to Idaho Power's incurring the bulk of the associated costs. On December 2, 2013, the IPUC issued an order granting Idaho Power's application for a CPCN. The IPUC, however, denied the company's additional request for early binding ratemaking treatment. The IPUC's order also requires that Idaho Power submit quarterly reports updating the IPUC on any changes to environmental policy or regulations until such time as the upgrades are in service, and that the company return to the IPUC if viable alternatives to the SCR upgrades become available.

Cost Recovery for Cessation of Boardman Coal-Fired Operations: In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The plan results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. In response to an application filed by Idaho Power, on February 15, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early plant shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On May 17, 2012, the IPUC issued an order approving a $1.5 million annual increase in Idaho-jurisdiction base rates, with new rates effective June 1, 2012. As of December 31, 2013, Idaho Power's net book value in the Boardman plant was $21.2 million.

Idaho Depreciation Rate Filings: Idaho Power's advanced metering infrastructure (AMI) project provides the means to automatically retrieve and store energy consumption information, eliminating manual meter reading expense. Commencing June 1, 2009, the IPUC approved a rate increase, coincident with a related increase in depreciation expense, allowing Idaho Power to recover the three-year accelerated depreciation of the existing non-AMI metering equipment and to begin earning a return on its AMI investment. On April 27, 2012, the IPUC approved Idaho Power's February 15, 2012 application requesting approval of a $10.6 million decrease in rates for specified customer classes, effective June 1, 2012, as a result of the removal of accelerated depreciation expense associated with non-AMI metering equipment.

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated service life estimates and net salvage percentages for all plant assets, and adjust Idaho-jurisdiction base rates to reflect the revised depreciation rates. On May 31, 2012, the IPUC issued an order approving a settlement stipulation providing for a $1.3 million annual decrease in Idaho-jurisdiction base rates, effective June 1, 2012.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues and an authorized rate of return on equity of 10.5 percent, with an Oregon retail rate base of approximately $121.9 million. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which the OPUC approved on February 23, 2012. The settlement stipulation 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.

Cost Recovery for Langley Gulch Power Plant: On September 20, 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

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its open access transmission tariff (OATT), which allows transmission rates to be updated annually based 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, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.32
October 1, 2011 to September 30, 2012	$ 19.79

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $118.2 million, which represents 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):

	2013	2012
First mortgage bonds:		
4.25% Series due 2013	$ —	$ 70,000
6.025% Series due 2018	120,000	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	—
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	—
Total first mortgage bonds	1,425,000	1,345,000
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	4,255	5,318
Unamortized premium/discount - net	(3,278)	(2,967)
Total Idaho Power outstanding debt(2)	1,616,322	1,537,696
Current maturities of long-term debt	(1,064)	(71,064)
Total long-term debt	$ 1,615,258	$ 1,466,632

(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, 2013 to $1.591 billion.
(2) At December 31, 2013 and 2012, the overall effective cost of Idaho Power's outstanding debt was 5.19 percent and 5.44 percent, respectively.

At December 31, 2013, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2014	2015	2016	2017	2018	Thereafter
$ 1,064	$ 1,064	$ 1,064	$ 1,064	$ 120,000	$ 1,495,344

Long-Term Debt Issuances, Maturities, and Availability

On April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds, Series I, maturing on April 1, 2023, and $75 million in principal amount of 4.00% first mortgage bonds, Series I, maturing on April 1, 2043. On October 1, 2013, Idaho Power used a portion of the net proceeds of the April 2013 sale of first mortgage bonds to satisfy its obligations upon maturity of $70 million in principal amount of 4.25% first mortgage bonds. Issuance of the Series I first mortgage bonds in April 2013, combined with the issuance of $200 million in principal amount of Series I first mortgage bonds in August 2010 and $150 million in principal amount of Series I first mortgage bonds in April 2012, utilized in full the available amount under a registration statement Idaho Power filed with the U.S. Securities and Exchange Commission (SEC) in May 2010 and under a selling agency agreement executed with ten banks in June 2010. In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 sale of first mortgage bonds to effect the early redemption in full of its $100 million of 4.75% first mortgage bonds due November 2012.

In February 2013, Idaho Power filed applications with the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) seeking authorization to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds. In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing such issuance and sales, subject to conditions specified in the orders. The order from the IPUC approved the issuance of the securities through April 9, 2015, subject to extension upon request to the IPUC. The OPUC’s and WPSC’s orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a maximum interest rate limit of 7 percent.

In anticipation of the issuances of the notes described above and the expiration of the prior registration statement, 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, 2013, Idaho Power had not sold any first mortgage bonds, including Series J Notes, or debt securities under the Selling Agency Agreement.

***Mortgage*:** As of December 31, 2013, Idaho Power could issue under its Indenture approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Indenture.

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

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

Idaho Power has a credit facility that may be used for general corporate purposes and commercial paper backup. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facility to $450 million, subject to certain conditions.

The interest rate for any borrowings under the facility is based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on Idaho Power's senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under the credit facility, the company pays a facility fee on the commitment based on the Idaho Power's credit rating for senior unsecured long-term debt securities. While the credit facility provided for an original termination date of October 26, 2016, the credit agreement grants Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. In October 2012, Idaho Power executed the First Extension Agreement with each of the lenders, extending the termination date under the credit facility to October 26, 2017. In October 2013, Idaho Power executed the Second Extension Agreement with each of the lenders, extending the termination date under the credit facility to October 26, 2018. No other terms of the credit facility, including the amount of permitted borrowings under the credit agreement, were affected by the extensions.

At December 31, 2013, no loans were outstanding under Idaho Power's facility. At December 31, 2013, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of Idaho Power's short-term borrowings were as follows at December 31, 2013 and December 31, 2012:

	2013	2012
Commercial paper balances:		
At the end of year	$ —	$ —
Average during the year	$ 2,209	$ 3,578
Weighted-average interest rate		
At the end of the year	—%	—%

6. COMMON STOCK

Idaho Power Common Stock

In 2012, IDACORP contributed $7.5 million of additional equity to Idaho Power. No contributions were made to Idaho Power in 2013. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

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 the credit facility or Idaho Power's Revised Code of Conduct. A covenant under Idaho Power's credit facility requires Idaho Power to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2013, the leverage ratio for Idaho Power was 49 percent. Based on these restrictions, Idaho Power's dividends were limited to $848 million at December 31, 2013. 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, 2013, 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, 2013, 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 $6.8 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 nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2013, the maximum number of shares available under the LTICP and RSP were 1,251,979 and 15,796, respectively.

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. Based on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. 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 shares of IDACORP common stock:

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2013	316,711	$ 32.32
Shares granted	106,467	42.53
Shares forfeited	(2,087)	38.05
Shares vested	(115,107)	29.52
Nonvested shares at December 31, 2013	305,984	$ 36.85

The total fair value of shares vested during the years ended December 31, 2013 and 2012 was $5.0 million and $4.9 million, respectively. At December 31, 2013, Idaho Power had $4.8 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 1.64 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2013, a total of 13,013 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $46.87 per share. Directors elected to defer receipt of 6,425 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2013, all compensation costs have been recognized. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

Idaho Power's stock option transactions are summarized below. Share amounts represent shares of IDACORP common stock:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
Outstanding at January 1, 2013	3,956	$ 29.75	2.05	$ 54
Exercised	(2,766)	29.75		

Outstanding at December 31, 2013	1,190	$	29.75	1.05	$ 26
Vested and exercisable at December 31, 2013	1,190	$	29.75	1.05	$ 26

The following table presents information about options exercised (in thousands of dollars):

	2013	2012
Intrinsic value of options exercised	$ 47	$ 36
Cash received from exercises	82	77
Tax benefits realized from exercises	19	14

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):

	2013	2012
Compensation cost	$ 4,783	$ 4,577
Income tax benefit	1,870	1,789

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2013, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2014	2015	2016	2017	2018	Thereafter
Cogeneration and power production	$ 170,155	$ 175,242	$ 173,982	$ 178,854	$ 186,219	$ 2,660,954
Power and transmission rights	4,801	4,815	4,790	4,214	1,179	4,739
Fuel	84,068	35,228	9,888	9,775	9,343	79,868

As of December 31, 2013, Idaho Power had 774 MW nameplate capacity of PURPA-related projects on-line, with an additional 68 MW nameplate capacity of projects projected to be on-line by the end of 2016. The power purchase contracts for these projects have terms ranging from one to 35 years. During 2013, Idaho Power purchased 2,126,644 megawatt-hours (MWh) from these projects at a cost of $131 million, resulting in a blended price of $61.75 per MWh. Idaho Power purchased 1,961,208 MWh at a cost of $118 million in 2012.

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

	2014	2015	2016	2017	2018	Thereafter
Operating leases	$ 1,357	$ 2,024	$ 1,155	$ 868	$ 892	$ 14,536
Equipment, maintenance, and service agreements	61,166	38,632	16,050	4,373	3,813	22,630
FERC and other industry-related fees	12,665	12,646	6,802	6,802	6,802	34,008

Idaho Power's expense for operating leases was approximately $5.2 million in 2013 and $6.0 million in 2012.

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 $74 million at December 31, 2013, 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, 2013, the value of the reclamation trust fund was $67 million. During 2013 the reclamation trust fund distributed approximately $28 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 historical experience and the evaluation of the specific indemnities. As of December 31, 2013, 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 within the 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 accrual for loss contingencies is 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 western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending proceedings and predict that these matters will not have a material adverse effect on Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds 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. The FERC has characterized these ripple claims as "speculative." However, the FERC has refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve a portion of a settlement that provided for waivers of all claims in those proceedings, despite only limited objections from two market participants. Idaho Power and IESCo petitioned the D.C. Circuit for review of the FERC's decision refusing to approve the waiver provision of the settlement, on the basis that the FERC failed to apply its established precedents and rules. The petition for review was transferred to the Ninth Circuit Court of Appeals in June 2013 and remains pending before that court.

Based on its evaluation of the merits of ripple claims and the inability to estimate the potential exposure should the claims ultimately have any merit, particularly in light of Idaho Power and IESCo being both purchasers and sellers in the energy market during the relevant period, Idaho Power and IESCo 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.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses. Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970s and early 1980s these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation in March 1988.

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power continues its participation in the SRBA in an effort to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, as of the date of this report Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

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, records 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 but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

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 was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power’s funding policy for the pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2013 and 2012 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	
	2013	**2012**	**2013**	**2012**
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 767,692	$ 655,439	$ 80,515	$ 65,043
Service cost	31,357	25,571	2,178	2,151
Interest cost	31,830	31,489	3,258	3,218
Actuarial (gain) loss	(112,215)	77,328	(4,663)	13,335
Benefits paid	(23,571)	(22,135)	(3,515)	(3,232)
Projected benefit obligation at December 31	695,093	767,692	77,773	80,515
Change in plan assets:				
Fair value at January 1	460,862	390,081	—	—
Actual return on plan assets	77,801	48,616	—	—
Employer contributions	30,000	44,300	—	—

Benefits paid	(23,571)	(22,135)	—	—
Fair value at December 31	545,092	460,862	—	—
Funded status at end of year	$ (150,001)	$ (306,830)	$ (77,773)	$ (80,515)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,905)	$ (3,651)
Noncurrent liabilities	(150,001)	(306,830)	(73,868)	(76,864)
Net amount recognized	$ (150,001)	$ (306,830)	$ (77,773)	$ (80,515)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 120,587	$ 291,966	$ 26,102	$ 33,605
Prior service cost	642	989	1,077	1,289
Subtotal	121,229	292,955	27,179	34,894
Less amount recorded as regulatory asset	(121,229)	(292,955)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 27,179	$ 34,894
Accumulated benefit obligation	$ 591,649	$ 640,330	$ 70,530	$ 72,288

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 fair value of these investments was approximately $59.2 million and $50.4 million at December 31, 2013 and 2012, 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**	
	2013	**2012**	**2013**	**2012**
Service cost	$ 31,357	$ 25,571	$ 2,178	$ 2,151
Interest cost	31,830	31,489	3,258	3,218
Expected return on assets	(35,755)	(31,737)	—	—
Amortization of net loss	17,118	14,114	2,840	1,530
Amortization of prior service cost	347	347	212	212
Net periodic pension cost	44,897	39,784	8,488	7,111
Adjustments due to the effects of regulation(1)	(9,013)	(5,860)	—	—
Net periodic benefit cost recognized for financial reporting	$ 35,884	$ 33,924	$ 8,488	$ 7,111

(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. See Note 3 for information on Idaho Power's revenue sharing mechanism approved by the IPUC, which resulted in additional Idaho pension expense of $16.5 million in 2013 and $14.6 million in 2012.

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

	Pension Plan		**SMSP**	
	2013	**2012**	**2013**	**2012**
Actuarial gain (loss) during the year	$ 154,261	$ (60,448)	$ 4,664	$ (13,335)
Reclassification adjustments for:				
Amortization of net loss	17,118	14,114	2,840	1,530
Amortization of prior service cost	347	347	212	212
Adjustment for deferred tax effects	(67,136)	17,979	(3,017)	4,532
Adjustment due to the effects of regulation	(104,590)	28,008	—	—

Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ 4,699	$ (7,061)

In 2014, Idaho Power expects to recognize as components of net periodic benefit cost $7.2 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2013, relating to the pension plan and SMSP. This amount consists of $4.0 million of amortization of net loss and $0.4 million of amortization of prior service cost for the pension plan, and $2.6 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):

	2014	2015	2016	2017	2018	2019-2023
Pension Plan	$ 25,473	$ 27,371	$ 29,664	$ 32,133	$ 34,722	$ 212,683
SMSP	3,996	4,186	4,213	4,441	4,549	25,514

As of December 31, 2013, Idaho Power's minimum required contribution to the pension plan is estimated to be $1.4 million in 2014, though Idaho Power plans to contribute at least $20 million to the pension plan during 2014.

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):

	2013	2012
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 72,547	$ 66,669
Service cost	1,315	1,292
Interest cost	2,633	3,135
Actuarial (gain) loss	(16,788)	3,180
Benefits paid(1)	(2,366)	(1,729)
Benefit obligation at December 31	57,341	72,547
Change in plan assets:		
Fair value of plan assets at January 1	33,387	31,901
Actual return on plan assets	6,212	3,346
Employer contributions(1)	(122)	(131)
Benefits paid(1)	(2,366)	(1,729)
Fair value of plan assets at December 31	37,111	33,387
Funded status at end of year (included in noncurrent liabilities)	$ (20,230)	$ (39,160)

(1) Contributions and benefits paid are each net of $3,272 thousand and $3,268 thousand of plan participant contributions, and $372 thousand and $430 thousand of Medicare Part D subsidy receipts for 2013 and 2012, respectively.

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

	2013	2012
Net loss	$ (4,974)	$ 15,796

Prior service cost	328	99
Subtotal	(4,646)	15,895
Less amount recognized in regulatory assets	4,646	(15,895)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2013	2012
Service cost	$ 1,315	$ 1,292
Interest cost	2,633	3,135
Expected return on plan assets	(2,328)	(2,234)
Amortization of net loss	98	384
Amortization of prior service cost	(229)	(422)
Amortization of unrecognized transition obligation	—	2,040
Net periodic postretirement benefit cost	$ 1,489	$ 4,195

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

	2013	2012
Actuarial gain (loss) during the year	$ 20,673	$ (2,068)
Prior service cost arising during the year	—	—
Reclassification adjustments for:		
Amortization of net loss	98	384
Amortization of prior service cost	(229)	(422)
Amortization of unrecognized transition obligation	—	2,040
Adjustment for deferred tax effects	(8,031)	(153)
Adjustment due to the effects of regulation	(12,511)	219
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2014, Idaho Power expects to recognize as a component of net periodic benefit cost $0.2 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2013, relating to the postretirement benefit plan. The entire amount represents $0.2 million 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):

	2014	2015	2016	2017	2018	2019-2023
Expected benefit payments	$ 3,890	$ 4,000	$ 4,070	$ 4,130	$ 4,170	$ 21,290
Expected Medicare Part D subsidy receipts	430	470	510	550	600	3,820

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**	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Discount rate	5.20%	4.20%	5.10%	4.15%	5.15%	4.20%
Rate of compensation increase(1)	4.38%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.8%	6.5%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2013	12/31/2012	12/31/2013	12/31/2012	12/31/2013	12/31/2012

(1) The 2013 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.63% 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**	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Discount rate	4.20%	4.90%	4.15%	5.10%	4.20%	5.05%
Expected long-term rate of return on assets	7.75%	7.75%	—	—	7.25%	7.25%
Rate of compensation increase	4.38%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.8%	6.5%
Dental trend rate	—	—	—	—	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.8 percent in 2013 and is assumed to decrease gradually to 5.0 percent by 2097. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2013 (in thousands of dollars):

	One-Percentage-Point Increase	**One-Percentage-Point Decrease**
Effect on total of cost components	$ 374	$ (273)
Effect on accumulated postretirement benefit obligation	3,139	(2,415)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2013 for the pension asset portfolio by asset class is set forth below.

Asset Class	**Target Allocation**	**Actual Allocation December 31, 2013**
Debt securities	24%	20%
Equity securities	54%	57%

Real estate	6%	5%
Other plan assets	16%	18%
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 return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes. 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. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2013 and 2012.

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, 2013				
Pension plan assets:				
Cash and cash equivalents	$ 33,030	$ —	$ —	$ 33,030
Short-term bonds	—	11,068	—	11,068
Long-term bonds	—	95,336	—	95,336
Equity Securities: Large-Cap	71,042	—	—	71,042
Equity Securities: Mid-Cap	23,346	23,112	—	46,458
Equity Securities: Small-Cap	48,998	—	—	48,998
Equity Securities: Micro-Cap	24,687	—	—	24,687

Equity Securities: International	19,128	74,908	—	94,036
Equity Securities: Emerging Markets	3,523	22,107	—	25,630
Equity Securities: Market Neutral	3,870	—	—	3,870
Real estate	—	—	28,019	28,019
Private market investments	—	—	33,709	33,709
Commodities funds	—	29,209	—	29,209
Total pension assets	$ 227,624	$ 255,740	$ 61,728	$ 545,092
Postretirement plan assets(1)	$ 75	$ 37,036	$ —	$ 37,111

Assets at December 31, 2012				
Pension plan assets:				
Cash and cash equivalents	$ 7,628	$ —	$ —	$ 7,628
Short-term bonds	—	12,373	—	12,373
Long-term bonds	—	96,671	—	96,671
Equity Securities: Large-Cap	57,526	—	—	57,526
Equity Securities: Mid-Cap	19,944	16,780	—	36,724
Equity Securities: Small-Cap	36,409	—	—	36,409
Equity Securities: Micro-Cap	19,923	—	—	19,923
Equity Securities: International	19,461	59,142	—	78,603
Equity Securities: Emerging Markets	3,101	21,370	—	24,471
Equity Securities: Market Neutral	7,675	—	—	7,675
Real estate	—	—	27,874	27,874
Private market investments	—	—	30,507	30,507
Commodities funds	1,420	23,058	—	24,478
Total pension assets	$ 173,087	$ 229,394	$ 58,381	$ 460,862
Postretirement plan assets(1)	$ 325	$ 33,062	$ —	$ 33,387

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

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

	Private Equity	**Real Estate**	**Total**
Beginning balance - January 1, 2012	$ 27,786	$ 25,119	$ 52,905
Realized gains	95	742	837
Unrealized gains	1,387	1,271	2,658
Purchases	1,779	742	2,521
Sales	(540)	—	(540)
Ending balance - December 31, 2012	30,507	27,874	58,381
Realized gains	—	739	739
Unrealized gains	2,941	1,579	4,520
Purchases	89	4,726	4,815
Sales	—	(6,899)	(6,899)
Settlements	172	—	172
Ending balance - December 31, 2013	$ 33,709	$ 28,019	$ 61,728

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 $7 million in both 2013 and 2012.

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 December 31, 2013 and 2012 are $1.9 million and $2.6 million, respectively.

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 2013 and 2012 (in thousands of dollars):

	2013		2012	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,272,381	2.47%	$ 2,217,334	2.36%
Transmission	974,697	2.01%	931,403	2.02%
Distribution	1,459,666	2.72%	1,411,740	2.89%
General and Other	373,658	5.91%	355,295	6.47%
Total in service	5,080,402	2.69%	4,915,772	2.75%
Accumulated provision for depreciation	(1,940,654)		(1,871,810)	
In service - net	$ 3,139,748		$ 3,043,962	

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 are 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, 2013 (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	$ 560,868	$ 12,151	$ 284,683	33	771
Boardman	Boardman, OR	79,963	2,846	58,806	10	64
Valmy Units 1 and 2	Winnemucca, NV	358,985	21,060	195,016	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 $79 million and $75 million in 2013 and 2012, respectively.

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 $9 million each year from 2012 to 2013.

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 2013, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $2.7 million in the recorded AROs. The primary cause of the increase in the AROs in 2013 is an increased ARO for an evaporation pond at the Jim Bridger generating facility due to the identification of additional costs required to decommission the pond.

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

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the removal costs recorded as regulatory liabilities on Idaho Power's consolidated balance sheet as of December 31, 2013 and 2012.

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

	2013	2012
Balance at beginning of year	$ 22,982	$ 21,367
Accretion expense	1,041	984
Revisions in estimated cash flows	2,722	1,416
Liability settled	(980)	(785)
Balance at end of year	$ 25,765	$ 22,982

13. INVESTMENTS

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

	2013	2012
Idaho Power investments:		
Available-for-sale equity securities	$ 41,119	$ 31,913
Executive deferred compensation plan investments	1,153	2,478
Other investments	1	2
Total Idaho Power investments	$ 42,273	$ 34,393

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

The table below summarizes investments in equity securities as of December 31, 2013 and December 31, 2012 (in thousands of dollars).

	December 31, 2013			December 31, 2012		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ —	$ —	$ 41,119	$ 6,792	$ —	$ 31,913

The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2013	2012
Proceeds from sales	$ 25,661	$ —
Gross realized gains from sales	11,637	—
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, 2013 and December 31, 2012, no securities were in an unrealized loss position.

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 under derivative accounting guidance. 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, 2013 and 2012 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income(1) 2013	2012
Financial swaps	Off-system sales	$ (2,637)	$ 15,104
Financial swaps	Purchased power	947	(6,280)
Financial swaps	Fuel expense	731	(6,359)
Financial swaps	Other operations and maintenance	35	(302)
Forward contracts	Off-system sales	185	—
Forward contracts	Purchased power	(196)	—
Forward contracts	Fuel expense	217	(1,755)

(1) Excludes unrealized gains or losses 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 Instruments Summary

The tables 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, 2013 and 2012 (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, 2013							
Current:							
Financial swaps	Other current assets	$ 1,451	$ (175)	$ 1,276	$ 175	$ (175)	$ -
Financial swaps	Other current liabilities	373	(373)	-	1,975	(1,429) (1)	546
Forward contracts	Other current assets	109	-	109	-	-	-
Forward contracts	Other current liabilities	-	-	-	26	-	26
Long-term:							
Financial swaps	Other assets	189	(28)	161	28	(28)	-
Forward contracts	Other assets	126	-	126	-	-	-
Total		$ 2,248	$ (576)	$ 1,672	$ 2,204	$ (1,632)	$ 572
December 31, 2012							
Current:							
Financial swaps	Other current assets	$ 5,122	$ (1,683) (1)	$ 3,439	$ 978	$ (978)	$ -
Financial swaps	Other current liabilities	320	(320)	-	1,372	(319)	1,053
Forward contracts	Other current assets	155	(4)	151	4	(4)	-
Forward contracts	Other current liabilities	-	-	-	2	-	2
Long-term:							
Financial swaps	Other assets	96	-	96	-	-	-
Forward contracts	Other assets	189	-	189	-	-	-
Total		$ 5,882	$ (2,007)	$ 3,875	$ 2,356	$ (1,301)	$ 1,055

(1) Current liability and current asset derivative amounts offset include $1.1 million and $0.7 million of collateral receivable and payable for the periods ending December 31, 2013 and 2012, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2013 and 2012 (in thousands of units).

		December 31,	
Commodity	Units	2013	2012
Electricity purchases	MWh	89	405
Electricity sales	MWh	603	1,374
Natural gas purchases	MMBtu	10,804	13,477
Natural gas sales	MMBtu	555	3,933
Diesel purchases	Gallons	906	834

Credit Risk

At December 31, 2013, 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 appropriate 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, 2013, was $2.1 million. Idaho Power posted $4.1 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2013, Idaho Power would have been required to post $10.0 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS

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

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

- Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that Idaho Power 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 the significance of a particular input to the fair value measurement requires judgment. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value of assets and liabilities and their placement within the fair value hierarchy. An item recorded at fair value is reclassified between 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, 2013 and 2012.

The table below presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2013 and 2012 (in thousands of dollars).

	December 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivatives	$ 1,437	$ 235	$ —	$ 1,672	$ 2,201	$ 1,674	$ —	$ 3,875
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	1,153	—	—	1,153	2,478	—	—	2,478
Available-for-sale securities: Equity securities	41,119	—	—	41,119	31,913	—	—	31,913
Liabilities:								
Derivatives	$ 546	$ 26	$ —	$ 572	$ —	$ 1,055	$ —	$ 1,055

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

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2013 and 2012, using available market information and appropriate valuation methodologies.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Liabilities:				
Long-term debt(1)	$ 1,616,322	$ 1,600,248	$ 1,537,696	$ 1,819,213

(1) Long-term debt is categorized as Level 2 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. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for long-term debt are based upon quoted market prices of similar issues or the same issues in an inactive market.

16. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to the SMSP. The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2013 and 2012 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Unrealized Gains and Losses on Available-for-Sale Securities	Defined Benefit Pension Items	Total
December 31, 2013			
Balance at beginning of period	$ 4,136	$ (21,252)	$ (17,116)

Other comprehensive income before reclassifications	2,951	2,840	5,791
Amounts reclassified out of AOCI	(7,087)	1,859	(5,228)
Net current-period other comprehensive income	(4,136)	4,699	563
Balance at end of period	$ —	$ (16,553)	$ (16,553)
December 31, 2012			
Balance at beginning of period	$ 2,569	$ (14,191)	$ (11,622)
Other comprehensive income before reclassifications	1,567	(8,122)	(6,555)
Amounts reclassified out of AOCI	—	1,061	1,061
Net current-period other comprehensive income	1,567	(7,061)	(5,494)
Balance at end of period	$ 4,136	$ (21,252)	$ (17,116)

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, 2013 and 2012 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI	
	Year Ended December 31,	
	2013	**2012**
Unrealized gains on available-for-sale securities		
Realized gain on sale of securities(1)	$ (11,637)	$ —
Total before tax	(11,637)	—
Tax benefit(2)	4,550	—
Net of tax	(7,087)	—
Amortization of defined benefit pension items(3)		
Prior service cost	212	212
Net loss	2,839	1,530
Total before tax	3,051	1,742
Tax benefit(2)	(1,192)	(681)
Net of tax	1,859	1,061
Total reclassification for the period	$ (5,228)	$ 1,061

(1) The realized gain is included in Idaho Power's consolidated income statements 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 statements 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 $1.0 million in 2013 and $0.8 million in 2012.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million to Ida-West in 2013 and 2012.

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	2,569,291			(14,191,343)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,060,888
3	Preceding Quarter/Year to Date Changes in Fair Value	1,567,262			(8,121,767)
4	Total (lines 2 and 3)	1,567,262			(7,060,879)
5	Balance of Account 219 at End of Preceding Quarter/Year	4,136,553			(21,252,222)
6	Balance of Account 219 at Beginning of Current Year	4,136,553			(21,252,222)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(7,087,026)			1,858,601
8	Current Quarter/Year to Date Changes in Fair Value	2,950,473			2,840,246
9	Total (lines 7 and 8)	(4,136,553)			4,698,847
10	Balance of Account 219 at End of Current Quarter/Year				(16,553,375)

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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			(11,622,052)		
2			1,060,888		
3			(6,554,505)		
4			(5,493,617)	168,168,039	162,674,422
5			(17,115,669)		
6			(17,115,669)		
7			(5,228,425)		
8			5,790,719		
9			562,294	176,741,143	177,303,437
10			(16,553,375)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	5,080,401,799	5,080,401,799
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,080,401,799	5,080,401,799
9	Leased to Others		
10	Held for Future Use	7,090,431	7,090,431
11	Construction Work in Progress	327,000,038	327,000,038
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,414,492,268	5,414,492,268
14	Accum Prov for Depr, Amort, & Depl	1,940,654,182	1,940,654,182
15	Net Utility Plant (13 less 14)	3,473,838,086	3,473,838,086
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,919,582,910	1,919,582,910
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	21,071,272	21,071,272
22	Total In Service (18 thru 21)	1,940,654,182	1,940,654,182
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)	1,940,654,182	1,940,654,182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	28,932,486	566,788
4	(303) Miscellaneous Intangible Plant	31,251,010	10,240,028
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,189,199	10,806,816
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,707,109	
9	(311) Structures and Improvements	147,710,023	4,482,425
10	(312) Boiler Plant Equipment	563,349,928	18,599,131
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	147,772,008	16,539,673
13	(315) Accessory Electric Equipment	68,199,805	1,358,422
14	(316) Misc. Power Plant Equipment	15,717,771	1,329,224
15	(317) Asset Retirement Costs for Steam Production	10,213,514	-167,708
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	954,670,158	42,141,167
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	30,842,287	79,145
28	(331) Structures and Improvements	157,517,780	14,815,575
29	(332) Reservoirs, Dams, and Waterways	253,144,302	107,093
30	(333) Water Wheels, Turbines, and Generators	200,843,534	1,098,350
31	(334) Accessory Electric Equipment	46,647,411	5,819,535
32	(335) Misc. Power PLant Equipment	20,291,559	747,605
33	(336) Roads, Railroads, and Bridges	8,117,613	103,589
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	717,404,486	22,770,892
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	133,026,012	727,926
39	(342) Fuel Holders, Products, and Accessories	7,987,898	-5,870
40	(343) Prime Movers	226,810,698	9,928,613
41	(344) Generators	73,447,494	-93,970
42	(345) Accessory Electric Equipment	95,558,348	112,842
43	(346) Misc. Power Plant Equipment	5,738,614	100,855
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	545,259,070	10,770,396
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,217,333,714	75,682,455

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	35,576,162	511,568
49	(352) Structures and Improvements	70,136,891	23,515
50	(353) Station Equipment	365,354,962	25,033,247
51	(354) Towers and Fixtures	155,095,726	6,908,886
52	(355) Poles and Fixtures	120,356,581	9,126,774
53	(356) Overhead Conductors and Devices	184,492,014	3,912,965
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)	931,402,602	45,516,955
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,775,243	93,250
61	(361) Structures and Improvements	31,354,167	1,497,008
62	(362) Station Equipment	189,664,902	7,531,450
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	230,356,006	6,383,564
65	(365) Overhead Conductors and Devices	124,012,452	3,461,596
66	(366) Underground Conduit	46,833,883	-430,208
67	(367) Underground Conductors and Devices	197,732,139	10,432,428
68	(368) Line Transformers	451,211,644	25,491,015
69	(369) Services	56,853,354	301,238
70	(370) Meters	70,932,527	2,819,895
71	(371) Installations on Customer Premises	2,865,154	110,864
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,505,211	83,638
74	(374) Asset Retirement Costs for Distribution Plant	643,639	-109,927
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,411,740,321	57,665,811
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	16,120,205	461,420
87	(390) Structures and Improvements	93,653,452	9,854,598
88	(391) Office Furniture and Equipment	42,794,726	7,118,464
89	(392) Transportation Equipment	64,890,431	6,169,655
90	(393) Stores Equipment	1,877,822	31,723
91	(394) Tools, Shop and Garage Equipment	6,465,710	886,602
92	(395) Laboratory Equipment	12,255,095	544,612
93	(396) Power Operated Equipment	11,495,923	1,681,383
94	(397) Communication Equipment	39,930,187	5,438,171
95	(398) Miscellaneous Equipment	5,622,282	401,402
96	SUBTOTAL (Enter Total of lines 86 thru 95)	295,105,833	32,588,030
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)	295,105,833	32,588,030
100	TOTAL (Accounts 101 and 106)	4,915,771,669	222,260,067
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)	4,915,771,669	222,260,067

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
6,391			29,492,883		3
9,489,420			32,001,618		4
9,495,811			61,500,204		5
					6
					7
			1,707,109		8
4,584,702			147,607,746		9
7,263,673			574,685,386		10
					11
7,181,677			157,130,004		12
31,703			69,526,524		13
622,615			16,424,380		14
			10,045,806		15
19,684,370			977,126,955		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			30,921,432		27
312,245			172,021,110		28
29,637			253,221,758		29
261,013			201,680,871		30
175,335			52,291,611		31
40,337		5,462	21,004,289		32
37,767			8,183,435		33
					34
856,334		5,462	739,324,506		35
					36
			2,690,006		37
			133,753,938		38
			7,982,028		39
99,723			236,639,588		40
			73,353,524		41
			95,671,190		42
			5,839,469		43
					44
99,723			555,929,743		45
20,640,427		5,462	2,272,381,204		46

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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
			36,087,730		48
85,325			70,075,081		49
1,911,076		457,970	388,935,103		50
			162,004,612		51
368,153			129,115,202		52
316,103			188,088,876		53
					54
					55
			390,266		56
					57
2,680,657		457,970	974,696,870		58
					59
9,346			4,859,147		60
19,774		-10,790	32,820,611		61
480,964		50,428	196,765,816		62
					63
1,190,154			235,549,416		64
1,439,280			126,034,768		65
114,064			46,289,611		66
688,287			207,476,280		67
4,820,448			471,882,211		68
296,165			56,858,427		69
608,979			73,143,443		70
74,455			2,901,563		71
38,361			-38,361		72
			4,588,849		73
			533,712		74
9,780,277		39,638	1,459,665,493		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
1,950			16,579,675		86
580,256		10,790	102,938,584		87
8,353,281		-661,851	40,898,058		88
3,332,856			67,727,230		89
788			1,908,757		90
155,375			7,196,937		91
487,781		132,755	12,444,681		92
376,030			12,801,276		93
1,457,582		15,236	43,926,012		94
286,866			5,736,818		95
15,032,765		-503,070	312,158,028		96
					97
					98
15,032,765		-503,070	312,158,028		99
57,629,937			5,080,401,799		100
					101
					102
					103
57,629,937			5,080,401,799		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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
27				
28				
29				
30				
31				
32				
33				
34				
35				
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41				
42				
43				
44				
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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	73,623,990
2	ROLLUP RELIC COST HELLS CANYON	50,183,581
3	GATEWAY WEST 500KV LINE	23,726,804
4	ROLLUP RELIC COST OXBOW	23,294,385
5	BOARDMAN - HEMINGWAY 500 KV LI	19,833,927
6	HELLS CANYON RELICENSING OUTSI	17,759,283
7	CIAC LIABILITY RECLASS	8,654,509
8	BRIDGER UNDISTRIBUTED WORK ORD	5,653,210
9	VALMY UNDISTRIBUTED WORK ORDER	5,642,006
10	B2H PERMITTING 11/1/2011 & FOR	5,555,755
11	VALMY 98250588 DUST COLLECTOR	3,013,757
12	BROWNLEE TURBINE REFURBISHMENT	2,903,666
13	BOARDMAN 1-1760 SO2 CONTROLS M	2,665,172
14	TFSN1003: REPLACE TWO METALCLA	2,661,327
15	VALMY 98301759 V1 UTILITY MACT	2,460,564
16	LEGAL DEPT. LABOR FOR RELICENS	2,214,774
17	B2H TLINE CONSTRUCTION COSTS	2,099,880
18	REL-HCC OREGON REAUTHORIZATION	2,023,191
19	LOWER MALAD TURBINE REPLACEMEN	1,574,233
20	NEW BUILDING PURCHASE - 5701 W	1,563,645
21	BRIDGER 2011C038 JB3 SCR SYS D	1,536,442
22	VALMY98314221 VC CAUSTIC TANK	1,526,976
23	VALMY 98306280 V2 SCRUBBER SPR	1,399,271
24	BRIDGER 2012C71 U2 GSU TRANSFO	1,351,165
25	HCC WATERSHED ENHANCEMENT PROG	1,335,925
26	CLEAR LAKES INTAKE AND SPILLWA	1,245,791
27	HBND-041:ALT LINE ROUTE TO GAR	1,118,782
28	VALMY 98306281V2 SCRUBBER INLE	1,050,512
29	IPC*SHARE OF BRIDGER-BORAH TAP	1,049,581
30	RELICENSING: BAKER COUNTY SETT	1,030,476
31	IPC'S SHARE OF BRIDGER-KINPORT	1,029,894
32	WDRI-KCHM NEW 138KV	1,024,338
33	IPCO/ / 2011 DOWNTOWN CAPITAL	1,014,499
34	BCWO - COMMUNICATION UPGRADES	1,001,441
35	OTHER MINOR PROJECTS UNDER $1,000,000	53,177,286
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	327,000,038

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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	1,848,861,113	1,848,861,113		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	121,486,191	121,486,191		
4	(403.1) Depreciation Expense for Asset Retirement Costs	587,012	587,012		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,478,949	3,478,949		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	99,141	99,141		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	125,651,293	125,651,293		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	48,122,830	48,122,830		
13	Cost of Removal	10,077,893	10,077,893		
14	Salvage (Credit)	2,294,255	2,294,255		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	55,906,468	55,906,468		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	CIAC, Reserve Adj and ARO Activity	976,972	976,972		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,919,582,910	1,919,582,910		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	532,889,244	532,889,244		
21	Nuclear Production				
22	Hydraulic Production-Conventional	378,129,481	378,129,481		
23	Hydraulic Production-Pumped Storage				
24	Other Production	58,193,252	58,193,252		
25	Transmission	300,179,069	300,179,069		
26	Distribution	543,191,784	543,191,784		
27	Regional Transmission and Market Operation				
28	General	107,000,080	107,000,080		
29	TOTAL (Enter Total of lines 20 thru 28)	1,919,582,910	1,919,582,910		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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			82,217,149
5				
6	Subtotal Idaho Energy Resources Company			84,680,243
7				
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40				
41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	84,680,243

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
6,704,329		88,921,478		4
				5
6,704,329		91,384,572		6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
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				39
				40
				41
6,704,329		91,384,572		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	42,388,239	41,546,323	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	15,899,274	16,506,169	
8	Transmission Plant (Estimated)	12,836,658	10,947,716	
9	Distribution Plant (Estimated)	17,335,350	20,538,847	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,384,672	1,274,973	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	47,455,954	49,267,705	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)	3,581,218	4,375,589	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	93,425,411	95,189,617	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	BLACK CANYON SISR	1,160	186623		186623
3	BPAP NETWORK SIS 78318516	2,248	186623	(10,000)	186623
4	BPAP NETWORK SIS 78862937	2,926	186623	(10,000)	186623
5	BPAP TRANS SIS 78225282	4,850	186623	(4,850)	186623
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	3 NORTH 3 EAST HYDRO GI 408	2,052	186623	(2,052)	186623
23	ALAMEDA SOLAR CENTER - GI 416	1,739	186623	(1,000)	186623
24	AMALSUGAR PAUL GI 389		186623	(2,067)	186623
25	BENSON CREEK WINDFARM GI 401	19,630	186623	(58,078)	186623
26	BLACK CANYON BLISS HYDRO		186623	500	186623
27	BURNT RIVER #2 PROJECT 251	3,571	186623		186623
28	BURNT RIVER PROJECT 209	8,538	186623		186623
29	DURBIN CREEK WINDFARM GI 402	323	186623	677	186623
30	EAGLE VIEW DAIRY GI 390		186623	6,199	186623
31	EIGHTMILE HYDRO GI 406	3,863	186623	(3,704)	186623
32	GRAND VIEW SOLAR TWO GI 369	6,580	186623	24,457	186623
33	GRANDVIEW PV SOLAR FIVE GI 411	9,063	186623	(1,000)	186623
34	GRANDVIEW PV SOLAR FIVEA GI 418	2,300	186623	(1,000)	186623
35	GRANDVIEW SOLAR 3 GI 394	2,177	186623	11,207	186623
36	GRANDVIEW SOLAR 4 GI 395	5,866	186623	(3,134)	186623
37	GROVE SOLAR CENTER - GI 414	4,102	186623	(1,000)	186623
38	HEAD OF THE U HYDRO GI 409	7,274	186623	(21,381)	186623
39	HORSE CREEK SOLAR CEN	2,171	186623	(1,000)	186623
40	HYLINE SOLAR CENTER - GI 419		186623	(1,000)	186623

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	JETT CREEK WINDFARM GI 403	323	186623	677	186623
23	LITTLE WOOD RIVER RANCH II GI 410	6,629	186623	(3,234)	186623
24	MAGPIE WIND PROJECT 235	3,613	186623		186623
25	MURPHY FLAT WIND FARM	21,282	186623	(43,814)	186623
26	OPEN RANGE SOLAR CENTER - GI 413	750	186623	(1,000)	186623
27	PROSPECTOR WINDFARM GI 404	323	186623	677	186623
28	SAGEBRUSH SOLAR CENTER - GI 415	847	186623	(1,000)	186623
29	SHOSHONE FALLS GI 136		186623	(47,512)	186623
30	SWAGER FARMS GI#307		186623	8,247	186623
31	TURNER SOLAR CENTER - GI 420		186623	(1,000)	186623
32	VALE AIR SOLAR CENTER - GI 412	6,333	186623	(1,000)	186623
33	WILLOW CREEK WINDFARM GI 405	323	186623	677	186623
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	13,583,873	3,685,134	230	503,192	16,765,815
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	ASC 815 Mark to Market - ST (182330)	1,054,643	4,552,513	244	3,978,706	1,628,450
5						
6	Regulatory Unfunded (182322)	677,795,470	44,058,546	282	11,371,613	710,482,403
7	Accum Deferred Income Noncurrent					
8						
9	PCA Deferral Idaho - IPUC Order #32821	52,349,489	72,949,308	1823	62,204,983	63,093,814
10	(Amort period 06/14 thru 05/15) (182323)					
11						
12	PCA Prior Year Deferral Idaho - IPUC Order #32821	(20,469,132)	84,361,221	various	33,473,696	30,418,393
13	(Amort period 06/11 thru 05/14) (182324)					
14						
15	Fixed Cost Adjusment (FCA) (182302)	8,830,218	17,193,424	1823	10,592,345	15,431,297
16	IPUC Order #32505 (amort period 06/14 thru 05/15)					
17						
18	Prior Year FCA IPUC Order #32811 (182309)	4,587,404	8,896,362	400	9,389,288	4,094,478
19	(Amort period 6/13 thru 5/14)					
20						
21	FERC Grid West Expense (182304)	27,932		401	27,932	
22	ER08-629-000 (amort period 05/08 thru 04/13)					
23						
24	AOCI Impact of Unfunded Post Retirement Liability	15,895,315	371,073	228	20,912,418	-4,646,030
25	IPUC Order #30256 (182306)					
26						
27	Oregon Pension Expense Capitalized (182339)	1,904,385	690,998	401/4073	70,904	2,524,479
28	OPUC Order #10-064 (amort period thru 2050)					
29						
30	Deferred Pension Expense Net of Contributions	12,839,861	43,199,940	1823/228	28,977,144	27,062,657
31	IPUC Order #30333 (182321)					
32						
33	AOCI Impact of Unfunded Pension Liability	292,954,561		228	171,725,978	121,228,583
34	IPUC Order #30256 (182320)					
35						
36	PCA Unbilled Forecast IPUC Order #32821 (182325)			401	6,092,288	-6,092,288
37						
38	PCAM Oregon 2008 (182346)	6,977,400	560,900			7,538,300
39	OPUC Order #08-238 & UE277 (Amort 1/14 - 7/17)					
40						
41	PCAM Interest Reserve 2008 (182329)	(600,282)		421	193,045	-793,327
42	OPUC Order #08-238 & UE 277 (Amort 1/14 - 7/17)					
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Excess Power Cost Deferral 2007 (182358)	2,403,512	39,131	401/421	2,415,728	26,915
2	IPUC Order #09-189 (amort period 1/11 - 1/14)					
3						
4	2007 EPC Interest Reserve (182351)	(159,661)	157,756			-1,905
5	IPUC Order #09-189 (amort period 1/11 - 1/14)					
6						
7	Idaho Boardman Decomissioning #32549 (182493)		5,816,903	various	5,067,163	749,740
8						
9						
10	2009 Reorg IPUC Order #30914 (182318)	461,311		401	230,656	230,655
11	(amort period 01/10 thru 12/14)					
12						
13	OATT Revenue Deferred Reserve (182336)	1,663,044		400	688,156	974,888
14	IPUC Order #30940 (amort period 06/12 thru 5/15)					
15						
16	Idaho Pension Cash (182327)	50,036,087	39,850,900	401/421	44,366,567	45,520,420
17	IPUC Order #32248 (amort period 06/11 thru 05/14)					
18						
19	FERC Pension Cash (182328)	214,461	36,000	401	250,461	
20	IPUC Order #32248 (amort period 06/11 thru 12/13)					
21						
22	Excess Power Cost Unbilled Amort (186356)	(137,422)	2,262,810	401	2,261,487	-136,099
23						
24	Cus Efficiency Incentive IPUC Order #32245 (182317)	14,086,201	1,359,810	254	15,446,011	
25						
26	Cus Efficiency Incen Res IPUC Order #32245 (182314)	(916,465)	1,168,879	1823/421	252,414	
27						
28	Lidar Surveys IPUC Order #32426 (182361)	392,442		402	43,605	348,837
29	(amort period 01/12 thru 12/21)					
30						
31	Bennett Mtn Maintenance IPUC Order #32426	224,660		402	74,887	149,773
32	(amort period 01/12 thru 12/15) (182379)					
33						
34	PCA Unbilled Amortization (182316)	2,691,278	34,263,627	400/401	39,531,606	-2,576,701
35						
36	Idaho Boardman ARO Order #32549 (182393)	1,376,053		403/411	172,006	1,204,047
37	(amort period thru 2020)					
38	Langley Revenue Accrual Order #12-226 (182398)	807,394	64,690			872,084
39						
40	Minor items (24)	236,694	440,287	various	401,540	275,441
41						
42						
43						
44	**TOTAL :**	1,141,110,726	365,980,212		470,715,819	1,036,375,119

Schedule Page: 232.1 Line No.: 40 Column: a

Accounts included in minor items:
182300
182312
182313
182334
182335
182352
182353
182354
182362
182366
182367
182369
182371
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182397
182399
182494

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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 ROW (186160)	738,195	20,121	401	98,482	659,834
2	Rents/Easements Long Term					
3						
4	Advance Prepaid (186709)	1,333,946		151	27,411	1,306,535
5	Coal Royalties					
6						
7	Security plan (186720)	18,496,667	986,191	143/426	1,367,427	18,115,431
8	Net Insurance Asset					
9						
10	American Falls Bond Ref(186722)	177,052		401	14,552	162,500
11	(Amort 04/00 - 02/25)					
12						
13	Prepaid Credit Facility(186025)	962,061	1,140,541	431	1,195,531	907,071
14	(amort period 10/12 thru 10/17)					
15						
16	Company Owned (186726)	4,149,412	1,666,835	426	1,894,606	3,921,641
17	Life Insurance					
18						
19	American Falls Water Rights	12,590,939		401	1,042,009	11,548,930
20	(amort 01/06 - 02/25) (186727)					
21						
22	Milner Bond Guarantee (186734)	5,318,182		253	1,063,637	4,254,545
23	(Amort 02/07 - 2/17)					
24						
25	American Falls - Bond refinance	583,990		401	47,999	535,991
26	(Amort through 02/25)(186770)					
27						
28	Shelf Registration (186732)		160,491	186	22	160,469
29						
30	Prepaid Exp (186052)	1,148,188	652,196	various	962,674	837,710
31	Contract I.T. Long Term					
32						
33	Long Term (186121)	1,214,665		228/401	28,335	1,186,330
34	Workers Compensation					
35						
36	Power Plant- Valmy (186793)	16,495	123			16,618
37						
38	Power Plant- Boardman (186794)	1,599		107/401	1,599	
39						
40	Transmission & Generation	1,222,226	2,360,326	various	3,503,008	79,544
41	Studies (186623)					
42						
43	Prepaid Coal LT (186797)	5,958,328		151/401	4,500,000	1,458,328
44						
45	Minor Items & Job Orders (2)	1,905	1,684,728	various	1,629,344	57,289
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	53,913,850				45,208,766

Schedule Page: 233 Line No.: 45 Column: a

Accounts included in minor items:
186255
186946

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	109,509,600	118,958,964
6			
7	Other (See footnote)	185,672,424	106,991,643
8	TOTAL Electric (Enter Total of lines 2 thru 7)	295,182,024	225,950,607
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	21,080,753	20,824,214
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	316,262,777	246,774,821

Notes

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

	Beginning Balance	Ending Balance
Federal NOL-Operating	45,964,500	28,544,014
Regulatory Asset-Non Current	4,458,718	23,538,502
Prov for Rate Refund-HC Relicensing (AFUDC)	17,855,802	23,062,458
Deferred Idaho ITC	13,747,559	15,346,759
VEBA-Post Retirement Benefits	9,221,017	9,962,466
Stock Based Compensation-FAS123R	3,148,063	3,532,282
Revenue Sharing	2,795,770	2,972,019
Rate Case Disallowance	2,505,417	2,389,579
Pension Expense-Oregon	1,897,934	2,204,483
Construction Advances	3,009,900	2,059,244
Regulatory Liability-Current	1,722,247	1,826,860
Valmy Union Pacific Contract	884,286	1,083,462
Postretirement Benefits-SFAS112	822,852	579,781
CSPP Co-Generator Overpayment	0	470,282
Executive Deferred Compensation	968,904	450,715
Asset Retirement Obligation (ARO)	0	425,053
Oregon NOL-Operating	262,521	247,299
Bridger Revenue Deferral	65,767	191,185
Provision for Rate Refunds	8,895	155,600
Montana NOL-Operating	78,812	101,480
Non-VEBA Pension and Benefits	217,768	82,596
Deferred GBC Federal	24,000	31,500
Boardman Decommission	(151,131)	(298,653)
Total Other Electric	109,509,600	118,958,964

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Regulatory Asset-FASB 109	51,285,735	50,788,061
Pension-FAS 158	114,530,586	47,394,315
Minimum Pension Liability	13,641,829	10,625,633
Postretirement Plan-FAS 158	6,214,273	(1,816,365)
Total Other	185,672,424	106,991,643

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Senior Management Security Plan	17,720,515	19,664,453
Micron CIAC-Depr Timing Diff	812,600	574,719
Federal NOL-Non Operating	850,678	534,662
Meridian Gold CIAC-Depr Timing Diff	64,230	42,118
Oregon NOL-Non Operating	5,037	6,409
Montana NOL-Non Operating	1,679	1,854
SMSP-Market Change of Rabbi Investments	1,626,015	0
Total Non Electric	21,080,753	20,824,214

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock all of which is held by	50,000,000	2.50	
3	IdaCorp, Inc. and not traded			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

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

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
2		
3		
4		
5		
6		
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8		
9		
10	Explanation of Changes during the year:	
11		
12		
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21		
22	TOTAL	2,096,925

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	4.25%Series due 2013	70,000,000	641,201
19			372,696 D
20			
21	4.00% Series due 2043	75,000,000	742,017
22			193,836 D
23			
24	6.00% Series due 2032	100,000,000	1,191,216
25			543,244 D
26			
27	5.875% Series due 2034	55,000,000	-585,759
28			746,961 D
29			
30	5.50% Series due 2034	50,000,000	524,419
31			383,322 D
32			
33	TOTAL	1,697,045,000	27,921,281

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	4.85% Series Due 2040	100,000,000	1,284,871
2			169,984 D
3			
4	6.30% Series due 2037	140,000,000	1,495,799
5			278,367 D
6			
7	6.25% Series due 2037	100,000,000	1,141,489
8			267,677 D
9			
10	Port of Morrow Variable due 2027	4,360,000	188,545
11	Humboldt Variable due 2024	49,800,000	1,697,856
12	Sweetwater Variable due 2026	116,300,000	3,026,122
13			
14	2.50% Series due 2023	75,000,000	648,267
15			371,854 D
16			
17	6.025 % Series Due 2018	120,000,000	1,630,120
18			
19	4.30% Series Due 2042	75,000,000	802,240
20			49,417 D
21	2.95% Series Due 2022	75,000,000	708,490
22			127,607 D
23	Subtotal Account 221	1,665,460,000	27,921,281
24			
25	Account 222 - Reaquired Bonds		
26			
27	Account 223: Advances for Associated Companies		
28			
29	Account 224:		
30	Bond Guarantee - American Falls	19,885,000	
31	Note Guarantee - Milner Dam	11,700,000	
32	Subtotal Account 224	31,585,000	
33	TOTAL	1,697,045,000	27,921,281

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
05/01/03	10/01/13	05/01/03	09/29/13		2,231,250	18
						19
						20
4/8/2013	4/1/2043	4/8/2013	4/1/2043	75,000,000	2,191,667	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
						26
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	27
						28
						29
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	30
						31
						32
				1,619,599,545	81,492,149	33

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.
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	1
						2
						3
6/22/07	6/15/2037	6/22/07	6/15/37	140,000,000	8,820,000	4
						5
						6
10/18/07	10/15/2037	10/18/07	10/15/37	100,000,000	6,250,000	7
						8
						9
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	30,241	10
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	11
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	12
						13
4/8/2013	4/1/2023	4/8/2013	4/1/2023	75,000,000	1,369,791	14
						15
						16
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	17
						18
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	19
						20
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	21
						22
				1,595,460,000	81,492,149	23
						24
						25
						26
						27
						28
						29
04/26/00	2/1/25			19,885,000		30
02/10/92				4,254,545		31
				24,139,545		32
				1,619,599,545	81,492,149	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	176,741,143
2		
3		
4	Taxable Income Not Reported on Books	
5		65,885,388
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-488,028
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		14,675,157
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		63,025,856
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	32,666,714
28	Show Computation of Tax:	
29	Tentative Tax @ 35%	11,433,350
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Name of Respondent Idaho Power Company	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report 2013/Q4

FOOTNOTE DATA

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4000-FEDERAL NOL	$	(77,958,875)
4003-CONSTRUCTION ADVANCES		(2,716,160)
4005-AVOIDED COST		5,234,452
4010-EMISSION ALLOWANCES		12,990
4013-CIAC-TAXABLE-ACCT 107		6,136,641
4021-ENGINEERING FEES-TAXABLE-ACCT 107		192,888
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES		3,877,707
4506-MERIDIAN GOLD CIAC-DEPR TIMING DIFF		(56,560)
4507-MICRON CIAC-DEPR TIMING DIFF		(608,471)
Total	**$**	**(65,885,388)**

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Total Federal and State taxes deducted on books	$	72,714,908
5001-BAD DEBT EXPENSE		628,831
5010-POSTEMPLOYMENT BENEFITS-SFAS112		(621,745)
5014-VACATION ACCRUAL TAX ADJ		(508,193)
5017-INJURIES & DAMAGES		19,758
5019-DEFERRED DIRECTORS FEES		(430,943)
5022-263A CAPITALIZED OVERHEADS		(25,000,000)
5023-PENSION EXPENSE		3,881,028
5024-NON-DEDUCTIBLE MEALS		500,000
5025-MILNER FALLING WATER		(143,745)
5028-OREGON OPERATING PROPERTY TAX ADJ		(84,806)
5033-NON-VEBA PENSION & BENEFITS		(345,752)
5035-PCA EXPENSE		(50,271,584)
5043-AMERICAN FALLS-FALLING WATER CONTRACT		219,181
5046-EXECUTIVE DEFERRED COMP-SHORT TERM		(342,126)
5047-EXECUTIVE DEFERRED COMP-LONG TERM		(983,334)
5052-AMORTIZATION OF ACCOUNT 181		261,992
5053-STOCK BASED COMPENSATION-FAS123R		878,293
5055-OPUC GRID WEST LOANS		14,191
5056-FERC GRID WEST EXPENSE		27,932
5057-INTERVENER FUNDING ORDERS		(68,034)
5058-FIXED COST ADJUSTMENT		(6,108,154)
5059-PS & I COSTS		2,492
5060-OREGON-PCAM		(367,855)
5061-PENSION EXPENSE-OREGON		1,382,793
5062-2011 LIDAR SURVEYS DEFERRAL		43,605
5063-BENNETT MTN MAINT DEFERRAL		74,886
5064-BRIDGER REVENUE DEFERRAL		320,803
5065-VALMY UNION PACIFIC CONTRACT		509,465
5066-BOARDMAN DECOMMISSION		(377,341)
5067-ASSET RETIREMENT OBLIGATION (ARO)		587,012
5068-CSPP CO-GENERATOR OVERPAYMENT		1,202,920
5501-SMSP-INSURANCE COSTS		(63,210)
5502-SMSP-MARKET CHANGE OF RABBI INVESTMENTS		(4,159,138)
5503-EDC-UNREALIZED GAIN/LOSS FROM RABBI TRUST		(168,146)
5504-NON-DEDUCTIBLE POLITICAL EXPENSES		961,599
5505-SENIOR MANAGEMENT SECURITY PLAN		4,972,345
5510-FINES & PENALTIES-OPERATING.		449,663

5516-NON-DEDUCTIBLE POLITICAL EXP-O&M ACCTS		100,000
5517-SMSP-UNREALIZED GAIN/LOSS FROM RABBI TRUST		57,419
5531-RATE CASE DISALLOWANCES		(296,299)
5532-DELIVERY ACCRUALS		41,261
Total	**$**	**(488,028)**

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

7009-PROVISION FOR RATE REFUNDS	$	(375,254)
7010-PROV FOR RATE REFUND-HC RELICENSING (AFUDC)		(13,317,958)
7011-OATT REVENUE DEFICIENCY		(688,156)
7012-REVENUE SHARING		(450,822)
7013-LANGLEY REVENUE ACCRUAL		46,154
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		6,704,329
7502-ALLOWANCE FOR OFUDC		14,857,580
7503-ALLOWANCE FOR BFUDC		7,663,190
7509-SMSP-INSURANCE PROCEEDS		236,094
Total	**$**	**14,675,157**

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

8001-VEBA-POST RETIREMENT BENEFITS	$	(1,976,010)
8009-DEPR TIMING DIFF-OPERATING		6,606,415
8016-VEBA-POST RETIRE BENEFITS-MEDICARE PART D		49,599
8020-CONSERVATION EXPENSES		(133,592)
8027-NEVADA OPERATING PROPERTY TAX ADJ		(106,412)
8034-REMOVAL COSTS		10,076,225
8038-OREGON EXCESS POWER COSTS		(2,217,518)
8041-AMERICAN FALLS REFINANCE-OLD COSTS		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT		(1,060,585)
8057-REORGANIZATION COSTS		(230,656)
8059-SOFTWARE-LABOR COSTS DEDUCTED-ACCT 107		500,000
8072-RELICENSING-LABOR COSTS DEDUCTED-ACCT 107		1,800,000
8073-REPAIRS DEDUCTION		55,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES		(293,520)
8079-CUSTOM EFFICIENCY INCENTIVE PAYMENTS		(13,169,736)
8501-COLI-INSURANCE COSTS		116,161
8504-OREGON NON-OP PROPERTY TAX ADJUSTMENT		14
8703-IPCO-162 (M) $1m THRESHOLD		(119,723)
8901-REGULATORY ASSET-CURRENT		48,803,642
8901-REGULATORY ASSET-NON CURRENT		(48,803,642)
8902-REGULATORY LIABILITY-CURRENT		(267,585)
8902-REGULATORY LIABILITY-NON CURRENT		267,585
IRS INTEREST EXPENSE		0
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		8,233,193
Total	$	63,025,856

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	10,546		10,744,029	5,837,537	
3	Social Security - (FOAB)	-8		14,188,639	14,188,644	
4	Unemployment			92,412	92,412	
5	Subtotal Federal	10,538		25,025,080	20,118,593	
6						
7	State of Idaho:					
8	Property	9,450,196		20,654,394	21,143,262	
9	Non-Operating	11,534		21,278	22,173	
10	Income	-2,489,982		5,445,052	3,095,003	
11	KWH	91,860		1,388,524	1,382,070	
12	Unemployment	1		946,357	946,358	
13	Regulatory Commission			2,176,398	2,176,398	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	7,063,609		30,632,153	28,765,414	
16						
17	State of Oregon					
18	Property		1,341,027	2,768,250	2,853,056	
19	Non-Operating Property		850	1,713	1,727	
20	Income	-125,615		212,882	93,729	
21	Regulatory Commission			164,189	164,189	
22	Unemployment			53,839	53,839	
23	Franchise	193,128		859,270	838,674	
24	Subtotal Oregon	67,513	1,341,877	4,060,143	4,005,214	
25						
26	State of Montana:					
27	Property	135,376		290,150	280,550	
28	Subtotal Montana	135,376		290,150	280,550	
29						
30	State of Nevada:					
31	Property		466,735	836,542	730,130	
32	Subtotal Nevada		466,735	836,542	730,130	
33						
34	State of Wyoming					
35	Corporate License			4,583	4,583	
36	Property	821,427		1,550,378	1,596,616	
37	Subtotal Wyoming	821,427		1,554,961	1,601,199	
38	Other States Income	11,324		121,578	4,817	
39	Payroll Tax Credit			-15,281,248		
40	Canada GST tax			-56	1,101	-2,681
41	TOTAL	8,109,787	1,808,612	47,239,303	55,507,018	-2,681

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
4,917,038		9,918,700			825,329	2
-13		14,188,639				3
		92,412				4
4,917,025		24,199,751			825,329	5
						6
						7
8,961,328		20,653,660			734	8
10,639					21,278	9
-139,933		5,177,565			267,487	10
98,314		1,388,524				11
		946,357				12
		2,176,398				13
		150				14
8,930,348		30,342,654			289,499	15
						16
						17
	1,425,833	2,637,037			131,213	18
	863				1,713	19
-6,462		204,664			8,218	20
		164,189				21
		53,839				22
213,724		859,270				23
207,262	1,426,696	3,918,999			141,144	24
						25
						26
144,976		290,150				27
144,976		290,150				28
						29
						30
	360,323	836,542				31
	360,323	836,542				32
						33
						34
		4,583				35
775,189		1,550,378				36
775,189		1,554,961				37
128,086		117,534			4,044	38
		-15,281,248				39
1,524		-56				40
15,104,410	1,787,019	45,979,287			1,260,016	41

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	601,446				59,448	
4	7%						
5	10%	22,463,428				1,415,863	
6	11%	1,213,883				26,030	
7	Other - State	55,617,846	411.4	2,344,250	411.4	1,618,222	
8	TOTAL	79,896,603		2,344,250		3,119,563	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	55,617,846	411.4	2,344,250	411.4	1,618,222	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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
541,998	10.12		3
			4
21,047,565	15.87		5
1,187,853	46.64		6
56,343,874	34.37		7
79,121,290			8
			9
			10
			11
56,343,874			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			23
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			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Smart Grid (253200)	4,644,939	107/401	313,305,643	309,560,953	900,249
2						
3	Point to Point Trans Study(253201)	875,653	242	975,466	999,515	899,702
4						
5	FTV (253202)	3,666,666	400	400,000		3,266,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Boardman To Hemingway (253220)	851,851	107	853,630	1,779	
9						
10	Sho Ban Trans ROW (253480)	232,500	242	15,000		217,500
11	(Amort Period Jan 2005-Dec 2027)					
12						
13	Milner Falling Water (253953)	859,480	186/401	1,063,636	919,891	715,735
14	Amort Period (Feb 1992 - Feb 2017)					
15						
16	Postretirement Benefits (253960)	2,104,751	401	621,745		1,483,006
17						
18	Directors Deferred Compensation	4,657,374	131	1,142,627	711,684	4,226,431
19	(253980-253999)					
20						
21	Operations Accrual (253550)		232/401	50,764	726,764	676,000
22	(amort period 1 year for dues)					
23						
24	USAF Battery Replacement (253906)	18	107	412,219	412,201	
25						
26	Minor Items (1)	89,640	various	117,152	28,944	1,432
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	17,982,872		318,957,882	313,361,731	12,386,721

Schedule Page: 269 Line No.: 26 Column: a

Accounts included in minor items:

253042

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	406,282,859	35,579,285	5,025,128
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	406,282,859	35,579,285	5,025,128
6	Non-Operating Property			
7	Other - Regulatory Asset for I	673,996,554		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,080,279,413	35,579,285	5,025,128
10	Classification of TOTAL			
11	Federal Income Tax	928,084,368	35,276,766	5,025,128
12	State Income Tax	152,195,045	302,519	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						436,837,016	2
							3
							4
						436,837,016	5
							6
		182	430,037	182	32,686,933	706,253,450	7
							8
			430,037		32,686,933	1,143,090,466	9
							10
			360,739		22,188,235	980,163,502	11
			69,298		10,498,698	162,926,964	12
							13

NOTES (Continued)

Name of Respondent Idaho Power Company	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report 2013/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 5 Column: b

	2013	Changes during Year				Adj Dr		Adj Cr		2013
	Beginning	DR to	CR to	DR	CR	Acct.		Acct.		Ending
Account (a)	Balance b	410.1 c	411.1 d	410.2 e	411.2 f	dr g	Amt h	dr i	Amt j	Balance k
Depreciation Timing Diff-Operating	390,753,887	33,953,833	644,887							424,062,833
Relicensing-Labor Costs Acct 107	14,494,453	(109,252)								14,385,201
CIAC-Taxable-Acct 107	858,810	305,015	4,224,734							(3,060,909)
Valmy Capitalized Items	274,766		76,500							198,266
Software-Labor Costs 107	138,254	1,429,689								1,567,943
Engineering Fees In Acct 107	(237,311)		79,007							(316,318)
TOTAL	406,282,859	35,579,285	5,025,128	0	0		0		0	436,837,016

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	56,986,228	61,579,372	26,893,284
4				
5				
6				
7				
8	Other -- See Note	123,400,688		
9	TOTAL Electric (Total of lines 3 thru 8)	180,386,916	61,579,372	26,893,284
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	772,235		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	181,159,151	61,579,372	26,893,284
20	Classification of TOTAL			
21	Federal Income Tax	151,966,147	51,656,107	22,559,541
22	State Income Tax	29,193,004	9,923,265	4,333,743
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						91,672,316	3
							4
							5
							6
							7
			77,822,738			45,577,950	8
			77,822,738			137,250,266	9
							10
							11
							12
							13
							14
							15
							16
							17
102,311	35,939					838,607	18
102,311	35,939		77,822,738			138,088,873	19
							20
85,824	30,148		65,281,976			115,836,413	21
16,487	5,791		12,540,762			22,252,460	22
							23

NOTES (Continued)

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

		Changes during Year				Adj Dr		Adj Cr		
Account (a)	Beginning Balance b	DR 410.1 c	CR 411.1 d	DR 410.2 e	CR 411.2 f	Acct. Cr g	Amt h	Acct. Dr i	Amt j	Ending Balance k
Pension Expense	21,525,276	8,562,581	9,855,340							20,232,517
PCA Expense	13,515,780	19,653,676								33,169,456
Conservation Expenses	5,113,679	1,829,204	5,533,857							1,409,026
Fixed Cost Adjustment	5,245,619	2,713,502	325,519							7,633,602
Regulatory Asset-Current	4,458,718	25,115,476	6,035,692							23,538,502
Oregon PCAM	2,493,134	143,813								2,636,947
Reg Liab-Non Current	1,722,247	2,417,922	2,313,310							1,826,860
Oregon Excess Pwr Costs	823,508	0	866,939							(43,431)
OATT Revenue Deficiency	650,167		269,035							381,132
Renewable Energy Certif	637,337	1,096,501	1,515,990							217,848
Langley Revenue Accrual	313,644	18,044								331,688
Reorganization Costs	180,350		90,175							90,175
2011 LIDAR Surveys De	153,425		17,047							136,378
Bennett Mtn Maint Def	87,831		29,277							58,554
Intervenor Funding Orders	56,239	26,599								82,838
OPUC Grid West Loans	12,020		5,548							6,472
FERC Grid West Exp	10,920		10,920							(0)
Emission Allowances	3,132	1,195	5,078							(751)
PS & I Costs	974		974							(0)
Bonus Deferral	(8,518)		2,452							(10,969)
Delivery Accruals	(9,255)	858	16,131							(24,528)
TOTAL	56,986,228	61,579,372	26,893,284	0	0		0		0	91,672,316

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

		Changes during Year				Adj Dr		Adj Cr		
Account (a)	Beginning Balance b	DR 410.1 c	CR 411.1 d	DR 410.2 e	CR 411.2 f	Acct. Cr g	Amt h	Acct. Dr i	Amt j	Ending Balance k
Pension-FAS 158	114,530,586					190	67,136,271			47,394,315
Postretirement Plan-FAS 158	6,214,273					190	8,030,639			(1,816,366)
Unrealized Gains on Market Sec	2,655,828					219	2,655,828			0
TOTAL	123,400,687	0	0	0	0		77,822,738		0	45,577,949

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

		Changes during Year				Adj Dr		Adj Cr		
Account (a)	Beginning Balance b	DR 410.1 c	CR 411.1 d	DR 410.2 e	CR 411.2 f	Acct Cr g	Amt h	Acct Dr i	Amt j	Ending Balance k
EDC-Unrealzd G/L From Rabbit Trust	469,524			79,228	13,491					535,261
SMSP-Unrealzd G/L From Rabbi Trust	0				22,448					(22,448)
Royalty Income	302,379			23,078						325,457
Oregon Non-Op Prop Tax Adj	332			5						337

FOOTNOTE DATA

TOTAL	772,235	0	0	102,311	35,939		0		0	838,607

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - (254001)	4,294,538	175	9,968,304	7,057,995	1,384,229
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	284,782	175	953,137	956,487	288,132
5	IPUC Order # 28661					
6						
7	OER 32368-323697 - (254007)	581,743	131/107	581,743		
8	Order # 32368					
9						
10	Unfunded Accum Def Income Tax (254966)	51,285,735	various	497,675		50,788,060
11						
12	Idaho DSM Rider (254201)	4,040,622	various	39,410,881	42,056,004	6,685,745
13	Order #29026					
14						
15	Oregon DSM Rider - (254202)	(3,914,935)	various	1,530,661	1,751,413	-3,694,183
16	Advise #05-03					
17						
18	Oregon Solar Pilot - (254005)	1,192,621	various	323,103	917,494	1,787,012
19	Order #10-198					
20						
21	Green Tags Oregon (254415)	154,393	1823	158,266	26,680	22,807
22	Order #11-086					
23						
24	Regulatory Unfunded Accum Def Income Tax (254419)	3,798,916		648,026	1,078,063	4,228,953
25						
26	Revenue Sharing (254101)	7,151,221	182	17,166,131	17,616,953	7,602,043
27	IPUC Order #32558					
28						
29	BPA Credit Residential Idaho (254401)	549,870	131/400	1,779,193	1,853,878	624,555
30	Advice # 11-03 (ID) #11-15 (OR)					
31						
32	WAQC Carryover (254901)	87,634	various	87,634	90,075	90,075
33	IPUC Order #29505					
34						
35	Idaho Boardman Decommissing - (254393)	(291,189)	400	500,300	791,489	
36	IPUC Order #32549					
37						
38	Oregon Boardman Decommissing - (254394)	(95,385)	400	23,145	118,530	
39	OPUC Order #12235					
40						
41	TOTAL	69,401,786		74,035,270	75,010,484	70,377,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Bridger Depreciation #12-296 -(254800)	168,224			320,803	489,027
2						
3						
4	Minor Items (6)	112,996	various	407,071	374,620	80,545
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
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24						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	69,401,786		74,035,270	75,010,484	70,377,000

Schedule Page: 278.1 Line No.: 4 Column: a

Accounts included in minor items:
254004
254006
254402
254403
254404
254411

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	513,914,273	431,555,478
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	436,445,539	375,354,223
5	Large (or Ind.) (See Instr. 4)	165,918,266	145,054,266
6	(444) Public Street and Highway Lighting	3,828,398	3,588,495
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,120,106,476	955,552,462
11	(447) Sales for Resale	54,472,513	61,534,224
12	TOTAL Sales of Electricity	1,174,578,989	1,017,086,686
13	(Less) (449.1) Provision for Rate Refunds	18,735,088	17,809,784
14	TOTAL Revenues Net of Prov. for Refunds	1,155,843,901	999,276,902
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,565,357	3,645,018
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	24,427,455	23,226,450
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	36,377,773	27,882,803
22	(456.1) Revenues from Transmission of Electricity of Others	21,936,382	21,054,698
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	86,306,967	75,808,969
27	TOTAL Electric Operating Revenues	1,242,150,868	1,075,085,871

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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
5,365,313	5,039,358	418,892	413,610	2
				3
6,040,697	5,881,587	83,439	82,485	4
3,181,866	3,132,573	117	118	5
31,478	31,798	2,205	2,069	6
				7
				8
				9
14,619,354	14,085,316	504,653	498,282	10
1,683,327	2,183,262			11
16,302,681	16,268,578	504,653	498,282	12
				13
16,302,681	16,268,578	504,653	498,282	14

Line 12, column (b) includes $ 10,892,103 of unbilled revenues.

Line 12, column (d) includes 36,316 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 11 Column: d

This amount is different from page 311 column G Total in the amount of 33 MWH due to a correction made to the Sales for Resale MWH that was not corrected in all systems.

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

This consists of :

Service Establishment/Connection Charges (Includes late and after hour charges)	$ 2,782,491
Field Collections Charges	266,120
Misc. Under $250,000	516,746
	$ 3,565,357

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

This consists of :

DSM Activity	$35,636,570
Stand-by-Service	352,915
Misc. items under $250,000	388,288
	$36,377,773

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	5,298,729	489,696,042	417,334	12,697	0.0924
3	03 - Residential Master Meter	4,498	392,266	23	195,565	0.0872
4	05 - Residential - TOD	28,009	2,473,244	1,535	18,247	0.0883
5	15 - Dusk to dawn lighting	2,701	640,768			0.2372
6	Unbilled Revenues	31,376	6,931,672			0.2209
7	Other Revenues		13,780,285			
8	Total 440	5,365,313	513,914,277	418,892	12,808	0.0958
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	161,915	18,460,738	30,656	5,282	0.1140
12	09P - General service	468,731	27,726,528	204	2,297,701	0.0592
13	09S - General service	3,288,901	223,240,990	32,439	101,387	0.0679
14	09T - General service	4,884	315,581	3	1,628,000	0.0646
15	15 - Dusk to Dawn Light	4,157	728,590			0.1753
16	19P - Uniform rate contracts	2,194,797	115,466,289	109	20,135,752	0.0526
17	19S - Uniform rate contracts	6,349	369,729	1	6,349,000	0.0582
18	19T - Uniform rate contracts	112,673	6,413,560	3	37,557,667	0.0569
19	24S - Irrigation Pumping	2,097,259	157,651,257	19,288	108,734	0.0752
20	40 - General service	11,032	891,263	850	12,979	0.0808
21	Special Contracts	866,564	39,897,579	3	288,854,667	0.0460
22	Commercial & Industrial Unbill	5,301	3,983,988			0.7516
23	Other Revenues		7,217,709			
24	Total 442	9,222,563	602,363,801	83,556	110,376	0.0653
25						
26	444 - Public Street Lighting:					
27	40 - General service	1,140	92,438	448	2,545	0.0811
28	41 - Street lighting	27,852	3,535,380	1,310	21,261	0.1269
29	42 - Traffic control lighting	2,847	164,601	447	6,369	0.0578
30	Unbilled	-361	-23,557			0.0653
31	Other Revenues		59,536			
32	Total 444	31,478	3,828,398	2,205	14,276	0.1216
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,583,038	1,109,214,373	504,653	28,897	0.0761
42	Total Unbilled Rev.(See Instr. 6)	36,316	10,892,103	0	0	0.2999
43	TOTAL	14,619,354	1,120,106,476	504,653	28,969	0.0766

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
2	Avista Corp.	SF	WSPP	n/a	n/a	n/a
3	Barclays Bank PLC	OS	-	n/a	n/a	n/a
4	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
5	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
6	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
7	BP Energy Company	SF	WSPP	n/a	n/a	n/a
8	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
9	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
10	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
11	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
12	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
13	Citigroup Energy Inc.	OS	-	n/a	n/a	n/a
14	City of Glendale	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)

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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
2	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
3	Constellation Energy Control & Dispatch	OS	WSPP	n/a	n/a	n/a
4	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
5	EDF Trading North America, LLC	OS	WSPP	n/a	n/a	n/a
6	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
7	Exelon Generation Company. LLC	SF	WSPP	n/a	n/a	n/a
8	Iberdrola Renewables, Inc,.	OS	WSPP	n/a	n/a	n/a
9	IIberdrola Renewables, Inc.	SF	WSPP	n/a	n/a	n/a
10	Iberdrola Renewables, Inc.	OS	WSPP	n/a	n/a	n/a
11	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
12	Jeffries Bache	OS	-	n/a	n/a	n/a
13	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
14	Macquarie Energy 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 Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

SALES FOR RESALE (Account 447)

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1	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
2	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
3	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
4	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
5	Nevada Power Company, dba NVEnergy	SF	WSPP	n/a	n/a	n/a
6	Noble Americas Gas & Power corp.	SF	WSPP	n/a	n/a	n/a
7	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
8	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
9	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
10	PacifiCorp Inc.	OS	T-7	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	WSPP	n/a	n/a	n/a
13	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
14	Powerex Corp.	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
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SALES FOR RESALE (Account 447)

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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	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
2	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
3	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
4	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
5	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
6	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
7	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
8	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
9	Royal Bank of Canada	OS	-	n/a	n/a	n/a
10	Seattle City Light	OS	WSPP	n/a	n/a	n/a
11	Seattle City Light	SF	WSPP	n/a	n/a	n/a
12	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
13	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
14	Shell Energy North America (US), L.P.	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
2	Shell Trading Risk Management	OS	WSPP	n/a	n/a	n/a
3	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
4	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
5	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
6	Sierra Pacific Power Co., dba NV Energy	SF	WSPP	n/a	n/a	n/a
7	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
8	Southern Cal Edison	OS	WSPP	n/a	n/a	n/a
9	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
10	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
11	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
12	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
13	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
14	TransAlta Energy Marketing (U.S.) Inc.	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	United Materials of Great Falls	LF	61	n/a	n/a	n/a
2	Prior Year Adjustments	AD	-	n/a	n/a	n/a
3	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
31,700		825,110		825,110	1
105,321		3,805,334		3,805,334	2
		217,584		217,584	3
35		1,450		1,450	4
			1,020	1,020	5
133,137		3,804,361		3,804,361	6
12,800		263,200		263,200	7
79		2,846		2,846	8
			447,121	447,121	9
		325,489		325,489	10
107,775		3,023,513		3,023,513	11
16		499		499	12
		23,311		23,311	13
31,200		1,231,764		1,231,764	14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

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.
22		1,114		1,114	1
819		28,000		28,000	2
3		111		111	3
42,424		1,685,969		1,685,969	4
		-31,268		-31,268	5
3,853		149,017		149,017	6
110,468		4,549,129		4,549,129	7
			54,244	54,244	8
11,492		296,328		296,328	9
75		1,275		1,275	10
16,350		471,697		471,697	11
		-1,980,404		-1,980,404	12
175,600		6,993,895		6,993,895	13
		-641,454		-641,454	14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

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.
			77	77	1
67,403		1,937,592		1,937,592	2
58,802		1,902,934		1,902,934	3
			215,585	215,585	4
25		650		650	5
800		23,640		23,640	6
280		5,150		5,150	7
13,850		644,137		644,137	8
34,702		1,062,479		1,062,479	9
89		2,509		2,509	10
			8,579	8,579	11
400		11,250		11,250	12
18,021		531,156		531,156	13
2,550		38,675		38,675	14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
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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.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,718		161,828		161,828	1
			90	90	2
375		3,150		3,150	3
16,469		444,786		444,786	4
1,000		23,100		23,100	5
7,565		220,410		220,410	6
			9,438	9,438	7
61,800		1,659,052		1,659,052	8
		-68,350		-68,350	9
350		8,700		8,700	10
1,266		39,931		39,931	11
			166,559	166,559	12
170		4,250		4,250	13
334,461		10,479,271		10,479,271	14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
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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.
		-303,626		-303,626	1
		-122,290		-122,290	2
82		2,490		2,490	3
			88,395	88,395	4
4,320		103,680		103,680	5
19,124		702,094		702,094	6
140		8,300		8,300	7
			288	288	8
			189	189	9
2,493		109,091		109,091	10
			567	567	11
227,968		8,210,959		8,210,959	12
			31,212	31,212	13
18,902		518,892		518,892	14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
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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.
		14,693		14,693	1
		2,403		2,403	2
			18,293	18,293	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
1,683,294	0	53,430,856	1,041,657	54,472,513	
1,683,294	**0**	**53,430,856**	**1,041,657**	**54,472,513**	

Schedule Page: 310 Line No.: 3 Column: b
ISDA Master agreement with Barclays Bank dated May 2, 2011

Schedule Page: 310 Line No.: 5 Column: b
Financial Transmission Losses

Schedule Page: 310 Line No.: 9 Column: b
Financial Transmission Losses

Schedule Page: 310 Line No.: 10 Column: b
ISDA Master Agreement with Cargill Power Markets LLC, dated June 13, 2011

Schedule Page: 310 Line No.: 13 Column: b
ISDA Master Agreement with CitiGroup Energy, Inc. dated March 7, 2011

Schedule Page: 310.1 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 310.1 Line No.: 5 Column: b
ISDA Master Agreement with EDF Trading North America, LLC

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

Schedule Page: 310.1 Line No.: 10 Column: b
Non-Firm Sales

Schedule Page: 310.1 Line No.: 12 Column: b
Prudential Bache Commodities (Jeffies Bache), LLC Futures Account Document, dated September 4, 2008

Schedule Page: 310.1 Line No.: 14 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

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

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

Schedule Page: 310.2 Line No.: 7 Column: b
Non-Firm Sales

Schedule Page: 310.2 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 310.2 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 12 Column: b
Non-Firm Sales

Schedule Page: 310.2 Line No.: 14 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 2 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 3 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 5 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 9 Column: b
ISDA Master Agreement with Royal Bank of Canada dated August 26, 2005

Schedule Page: 310.3 Line No.: 10 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 13 Column: b
Non-Firm Sales

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) __ An Original (2) X A Resubmission	04/15/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 1 Column: b

ISDA Master Agreement with Shell Energy North America dated November 1,2009 (all deals novated to Shell Trading Risk Managemet 10/13)

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

ISDA Master Agreement with Shell Energy North America dated November 1, 2009 (all deals novated to Shell Trading Risk Management 10/13)

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

Spinning or Operating reserves

Schedule Page: 310.4 Line No.: 4 Column: b

Financial Transmission Losses

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

Unit Contingent Sales

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

Financial Transmission Losses

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

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 11 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 13 Column: b

Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	1,524,957	1,402,743
5	(501) Fuel	160,276,741	134,501,103
6	(502) Steam Expenses	8,840,885	8,279,623
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,741,112	1,539,354
10	(506) Miscellaneous Steam Power Expenses	9,473,766	8,331,843
11	(507) Rents	348,322	285,311
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	182,205,783	154,339,977
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	101,619	331,355
16	(511) Maintenance of Structures	637,844	759,002
17	(512) Maintenance of Boiler Plant	12,461,886	12,605,603
18	(513) Maintenance of Electric Plant	5,398,984	5,139,307
19	(514) Maintenance of Miscellaneous Steam Plant	4,541,443	4,996,617
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,141,776	23,831,884
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	205,347,559	178,171,861
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	6,034,727	7,437,986
45	(536) Water for Power	5,679,423	7,810,554
46	(537) Hydraulic Expenses	13,572,536	12,715,046
47	(538) Electric Expenses	1,432,669	1,376,025
48	(539) Miscellaneous Hydraulic Power Generation Expenses	4,855,798	2,634,251
49	(540) Rents	141,597	329,209
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	31,716,750	32,303,071
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	83,805	305,070
54	(542) Maintenance of Structures	1,427,309	1,329,157
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,148,299	1,343,402
56	(544) Maintenance of Electric Plant	2,617,210	3,114,538
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,005,680	3,071,383
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,282,303	9,163,550
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	39,999,053	41,466,621

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	1,360,914	1,342,636
63	(547) Fuel	54,204,949	24,912,210
64	(548) Generation Expenses	3,427,130	2,167,816
65	(549) Miscellaneous Other Power Generation Expenses	585,699	403,386
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	59,578,692	28,826,048
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	99	
70	(552) Maintenance of Structures	301,287	208,028
71	(553) Maintenance of Generating and Electric Plant	131,162	99,722
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,233,983	2,537,689
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,666,531	2,845,439
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	61,245,223	31,671,487
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	214,941,823	190,640,708
77	(556) System Control and Load Dispatching	1,403,451	2,250
78	(557) Other Expenses	-34,629,989	-57,611,492
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	181,715,285	133,031,466
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	488,307,120	384,341,435
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,560,221	3,580,561
84			
85	(561.1) Load Dispatch-Reliability	39,635	130,631
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,702,334	1,170,321
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,036,729	1,345,152
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	94,561	97,740
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,403,457	2,359,494
94	(563) Overhead Lines Expenses	732,402	659,259
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,637,278	6,294,410
97	(566) Miscellaneous Transmission Expenses	49,579	175,701
98	(567) Rents	2,917,528	3,002,229
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,173,724	18,815,498
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	323,417	484,817
102	(569) Maintenance of Structures	7,617	
103	(569.1) Maintenance of Computer Hardware	7,491	13,444
104	(569.2) Maintenance of Computer Software	734,188	749,101
105	(569.3) Maintenance of Communication Equipment	4,564	4,138
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,610,183	3,689,469
108	(571) Maintenance of Overhead Lines	3,588,427	5,293,220
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	607	1,530
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,276,494	10,235,719
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	26,450,218	29,051,217

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	4,160,840	4,118,843
135	(581) Load Dispatching	3,529,347	3,549,914
136	(582) Station Expenses	1,375,049	1,157,508
137	(583) Overhead Line Expenses	3,111,427	3,786,758
138	(584) Underground Line Expenses	2,402,213	1,870,345
139	(585) Street Lighting and Signal System Expenses	74,337	109,636
140	(586) Meter Expenses	4,421,678	4,132,819
141	(587) Customer Installations Expenses	673,959	642,062
142	(588) Miscellaneous Expenses	5,754,224	5,622,888
143	(589) Rents	366,175	493,172
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,869,249	25,483,945
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	168,884	224,177
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,816,291	3,819,880
149	(593) Maintenance of Overhead Lines	14,492,291	15,554,326
150	(594) Maintenance of Underground Lines	645,600	1,046,527
151	(595) Maintenance of Line Transformers	286,874	422,582
152	(596) Maintenance of Street Lighting and Signal Systems	536,040	568,715
153	(597) Maintenance of Meters	750,543	725,957
154	(598) Maintenance of Miscellaneous Distribution Plant	412,978	529,977
155	TOTAL Maintenance (Total of lines 146 thru 154)	21,109,501	22,892,141
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,978,750	48,376,086
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	491,363	441,306
160	(902) Meter Reading Expenses	1,484,232	1,379,745
161	(903) Customer Records and Collection Expenses	14,060,136	13,188,955
162	(904) Uncollectible Accounts	5,805,414	4,512,906
163	(905) Miscellaneous Customer Accounts Expenses	271	413
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	21,841,416	19,523,325

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	531,496	535,711
168	(908) Customer Assistance Expenses	42,690,734	33,737,489
169	(909) Informational and Instructional Expenses	264,701	295,583
170	(910) Miscellaneous Customer Service and Informational Expenses	574,875	554,027
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	44,061,806	35,122,810
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	69,143,869	70,376,748
182	(921) Office Supplies and Expenses	17,610,990	18,940,073
183	(Less) (922) Administrative Expenses Transferred-Credit	26,882,864	28,236,018
184	(923) Outside Services Employed	5,271,865	5,177,361
185	(924) Property Insurance	3,673,489	3,506,576
186	(925) Injuries and Damages	5,694,399	7,150,892
187	(926) Employee Pensions and Benefits	62,531,128	61,791,248
188	(927) Franchise Requirements		9
189	(928) Regulatory Commission Expenses	3,975,664	5,692,486
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	496,936	493,057
192	(930.2) Miscellaneous General Expenses	4,246,371	4,026,891
193	(931) Rents	6,536	17,598
194	TOTAL Operation (Enter Total of lines 181 thru 193)	145,768,383	148,936,921
195	Maintenance		
196	(935) Maintenance of General Plant	5,252,115	5,160,763
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	151,020,498	154,097,684
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	778,659,808	670,512,557

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	Cogeneration and Small Power Producers					
2	AgPower Jerome/Double A Digester	LU	-	NA	NA	NA
3	Allan Ravenscroft/Malad River	LU	-	.488		
4	Bennett Creek Wind Farm	LU	-	NA	NA	NA
5	Bettencourt DryCreek Biofactory	LU	-	NA	NA	NA
6	Big Sky West Dairy Digester	LU	-	NA	NA	NA
7	Big Wood Canal Company					
8	Black Canyon #3	LU	-	NA	NA	NA
9	Jim Knight	LU	-	NA	NA	NA
10	Sagebrush	LU	-	NA	NA	NA
11	Blind Canyon Hydro	LU	-	NA	NA	NA
12	Branchflower/Trout Company	LU	-	NA	NA	NA
13	Burley Butte Wind Park	LU	-	NA	NA	NA
14	Bypass Limited	LU	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Camp Reed Wind Park	LU	-	NA	NA	NA
2	Cargill Inc./B6 Anaerobic Digester	LU	-	NA	NA	NA
3	Cassia Gulch Wind Park	LU	-	NA	NA	NA
4	Cassia Wind Farm	LU	-	NA	NA	NA
5	City of Cove, Oregon/Mill Creek	LU	-	NA	NA	NA
6	City of Hailey	LU	-	NA	NA	NA
7	City of Pocatello	LU	-	NA	NA	NA
8	Clear Springs Food Inc.	LU	-	NA	NA	NA
9	Clifton E. Jenson/Birchcreek	LU	-	.05		
10	Cold Springs Windfarm, LLC	LU	-	NA	NA	NA
11	Consolidated Hydro Inc./Enel					
12	Barber Dam	LU	-	NA	NA	NA
13	Dietrich Drop	LU	-	NA	NA	NA
14	GeoBon #2	LU	-	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.

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

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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	Lowline #2	LU	-	NA	NA	NA
2	Rock Creek #2	LU	-	NA	NA	NA
3	Contractors Power Group Inc./Mile 28	LU	-	NA	NA	NA
4	Crystal Springs Hydro	LU	-	NA	NA	NA
5	Curry Cattle Company	LU	-	.084		
6	David McCollum/Canyon Springs	LU	-	NA	NA	NA
7	David R Snedigar	LU	-	NA	NA	NA
8	Desert Meadow Wind Farm	LU	-	NA	NA	NA
9	Faulkner Brothers Hydro Inc.	LU	-	NA	NA	NA
10	Fisheries Development	OS	-	NA	NA	NA
11	Fossil Gulch Wind	LU	-	NA	NA	NA
12	G2 Energy Hidden Hollow	LU	-	NA	NA	NA
13	Glenns Ferry Cogen Partners/Magic	LU	-	NA	NA	NA
14	Golden Valley Wind Park	LU	-	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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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1	Hammett Hill Windfarm, LLC	LU	-	NA	NA	NA
2	Hazelton B Power Company	LU	-	NA	NA	NA
3	High Mesa Energy	LU	-	NA	NA	NA
4	H.K. Hydro Mud Creek S & S	LU	-	NA	NA	NA
5	Horeshoe Bend Hydro	LU	-	NA	NA	NA
6	Horseshoe Bend Wind/United Materials	LU	-	NA	NA	NA
7	Hot Springs Wind Farm	LU	-	NA	NA	NA
8	Idaho Winds/Sawtooth Wind Project	LU	-	NA	NA	NA
9	JR Simplot Co.	LU	-	NA	NA	NA
10	J.M. Miller/Sahko Hydro	LU	-	NA	NA	NA
11	James B. Howell/CHI Elk Creek	LU	-	NA	NA	NA
12	John R LeMoyne	LU	-	NA	NA	NA
13	Kasel & Witherspoon	LU	-	NA	NA	NA
14	Koyle Hydro Inc.	LU	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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	Lateral 10 Ventures	LU	-	NA	NA	NA
2	Lemhi Hydro Power Co./Schaffner	LU	-	NA	NA	NA
3	Lime Wind	LU	-	NA	NA	NA
4	Little Mac Power Co./Cedar Draw	LU	-	NA	NA	NA
5	Little Wood River Irrigation District	LU	-	NA	NA	NA
6	Magic Reservoir Hydro	LU	-	NA	NA	NA
7	Mainline Windfarm	LU	-	NA	NA	NA
8	Marco Rancher's Irrigation Inc.	LU	-	NA	NA	NA
9	Marysville Hydro Partners/Falls River	LU	-	NA	NA	NA
10	Milner Dam Wind Park	LU	-	NA	NA	NA
11	Mud Creek White Hydro, Inc	LU	-	NA	NA	NA
12	New Energy One/Rock Creek Diary	LU	-	NA	NA	NA
13	Oregon Trail Wind Park	LU	-	NA	NA	NA
14	Owyhee Irrigation District					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
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1	Mitchell Butte	LU	-	NA	NA	NA
2	Owyhee Dam	LU	-	NA	NA	NA
3	Tunnel #1	LU	-	NA	NA	NA
4	Paynes Ferry Wind Park	LU	-	NA	NA	NA
5	Pigeon Cove Power	LU	-	1.389		
6	Pilgrim Stage Station Wind Park	LU	-	NA	NA	NA
7	Pristine Springs Inc #1	LU	-	NA	NA	NA
8	Pristine Springs Inc #3	LU	-	NA	NA	NA
9	Reynolds Irrigation District	LU	-	NA	NA	NA
10	Richard Kaster					
11	Box Canyon	LU	-	NA	NA	NA
12	Briggs Creek	LU	-	NA	NA	NA
13	Rim View Trout Company	OS	-	NA	NA	NA
14	Riverside Hydro/Mora Drop	LU	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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1	Riverside Investments					
2	Arena Drop	LU	-	NA	NA	NA
3	Fargo Drop	LU	-	NA	NA	NA
4	Rock Creek #1 Joint Venture	LU	-	1.732		
5	Rockland Wind Project	LU	-	NA	NA	NA
6	Rupert Cogen Partners/Magic Valley	LU	-	NA	NA	NA
7	Ryegrass Windfarm	LU	-	NA	NA	NA
8	Salmon Falls Wind Park	LU	-	NA	NA	NA
9	SE Hazelton A LP	LU	-	NA	NA	NA
10	Shorock Hydro Inc.					
11	Shoshone Cspp	LU	-	NA	NA	NA
12	Shoshone #2	LU	-	NA	NA	NA
13	Snake Rivery Pottery	LU	-	NA	NA	NA
14	South Forks JointVenture/Lowline Canal	LU	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Tamarack Energy Partnership	LU	-	4.942		
2	Tasco - Nampa	OS	-	NA	NA	NA
3	Tasco - Twin Falls	OS	-	NA	NA	NA
4	Ted S. Sorenson/Tiber Dam	LU	-	NA	NA	NA
5	Thousand Spring Wind Park	LU	-	NA	NA	NA
6	Tuana Gulch Wind Park	LU	-	NA	NA	NA
7	Tuana Springs Expansion	LU	-	NA	NA	NA
8	Twin Falls Energy/Lowline Midway Hydro	LU	-	NA	NA	NA
9	Two Ponds Windfarm	LU	-	NA	NA	NA
10	White Water Ranch	LU	-	NA	NA	NA
11	William Arkoosh/Littlewood	LU	-	NA	NA	NA
12	Willis and Betty Deveny/Shingle Creek	LU	-	NA	NA	NA
13	Wilson Power Company	LU	-	NA	NA	NA
14	Yahoo Creek Wind Park	LU	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Reversal of Accrued Expense					
2	Interest Payments					
3	Scheduling Deviation					
4	Other Purchased Power					
5	Arizona Public Service Co.	SF	WSPP	NA	NA	NA
6	Avista Corp.	OS	T-12	NA	NA	NA
7	Avista Corp.	SF	WSPP	NA	NA	NA
8	Avista Corp.	OS	WSPP	NA	NA	NA
9	Barclays Bank PLC	OS	-	NA	NA	NA
10	Black Hills Power Inc.	SF	WSPP	NA	NA	NA
11	Bonneville Power Administration	OS	WSPP	NA	NA	NA
12	Bonneville Power Administration	OS	WSPP	NA	NA	NA
13	Bonneville Power Administration	SF	WSPP	NA	NA	NA
14	BP Energy Company	SF	WSPP	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Calpine Energy Services, L.P.	SF	WSPP	NA	NA	NA
2	Cargill Power Markets LLC	OS	-	NA	NA	NA
3	Cargill Power Markets LLC	SF	WSPP	NA	NA	NA
4	Chelan Co PUD	OS	WSPP	NA	NA	NA
5	Citigroup Energy Inc.	SF	WSPP	NA	NA	NA
6	Citigroup Energy Inc.	OS	-	NA	NA	NA
7	City of Glendale	SF	WSPP	NA	NA	NA
8	Constellation Energy Commodities Group	SF	WSPP	NA	NA	NA
9	Douglas County PUD	OS	WSPP	NA	NA	NA
10	EDF Trading North America, LLC	SF	WSPP	NA	NA	NA
11	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
12	Exelon Generation Company, LLC	SF	WSPP	NA	NA	NA
13	Grant CO Public Utility District #2 --	OS	WSPP	NA	NA	NA
14	Grant CO Public Utility District #2	SF	WSPP	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	IBERDROLA RENEWABLES, Inc.	SF	WSPP	NA	NA	NA
2	J. Aron & Company	SF	WSPP	NA	NA	NA
3	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	NA	NA	NA
4	Jefferies Bache	OS	-	NA	NA	NA
5	Los Angeles Dept Water & Power	SF	WSPP	NA	NA	NA
6	Macquarie Cook Power Inc.	SF	WSPP	NA	NA	NA
7	Macquarie Cook Power Inc.	OS	-	NA	NA	NA
8	Morgan Stanley Capital Group	SF	ISDA	NA	NA	NA
9	Nevada Power Co, DBA NV Energy	SF	WSPP	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	SF	WSPP	NA	NA	NA
11	Noble Americas Gas&Power Corp	SF	WSPP	NA	NA	NA
12	Northwestern Energy	OS	T-7	NA	NA	NA
13	NorthWestern Energy	SF	WSPP	NA	NA	NA
14	PacifiCorp Inc.	OS	T-13	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	PacifiCorp Inc.	SF	WSPP	NA	NA	NA
2	PacifiCorp Inc.	OS	WSPP	NA	NA	NA
3	Portland General Electric Company	OS	T-14	NA	NA	NA
4	Portland General Electric Company	SF	WSPP	NA	NA	NA
5	Powerex Corp.	SF	WSPP	NA	NA	NA
6	PPL EnergyPlus, LLC	SF	WSPP	NA	NA	NA
7	PPL EnergyPlus, LLC	OS	WSPP	NA	NA	NA
8	Public Service Company of New Mexico	SF	WSPP	NA	NA	NA
9	Puget Sound Energy, Inc.	OS	T-9	NA	NA	NA
10	Puget Sound Energy, Inc.	SF	WSPP	NA	NA	NA
11	Rainbow Energy Marketing Corporation	SF	WSPP	NA	NA	NA
12	Salt River Project	SF		NA	NA	NA
13	Seattle City Light	OS	WSPP	NA	NA	NA
14	Seattle City Light	SF	WSPP	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Shell Energy North America (US), L.P.	SF	WSPP	NA	NA	NA
2	Shell Energy North America (US), L.P.	OS	-	NA	NA	NA
3	Sierra Pacific Power Co., dba NV Energ	OS	T-55	NA	NA	NA
4	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	NA	NA	NA
5	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	NA	NA	NA
6	Snohomish County PUD	SF	WSPP	NA	NA	NA
7	Tacoma Power	OS	WSPP	NA	NA	NA
8	Tacoma Power	SF	WSPP	NA	NA	NA
9	Tenaska Power Services Co.	SF	WSPP	NA	NA	NA
10	The Energy Authority, Inc.	SF	WSPP	NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	NA	NA	NA
12	Tri-State Generation & Transmission	SF	WSPP	NA	NA	NA
13	Western Area Power Administration	OS	WSPP	NA	NA	NA
14	Raft River Energy I LLC	LU	-	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.

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

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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	Telocaset Wind Power Partners LLC	LU	APP-A	NA	NA	NA
2	Neal Hot Springs Unit #1	LU	-	NA	NA	NA
3	Net Metering Customers	OS	-	NA	NA	NA
4	Oregon Solar Customers	OS	-	NA	NA	NA
5	Prior Year Adjustments	AD				
6	Power Exchanges					
7	Bonneville Power Administration	EX	-	NA	NA	NA
8	EDF Trading North America, LLC	EX	-	NA	NA	NA
9	NorthWestern Energy	EX	-	NA	NA	NA
10	PacifiCorp Inc.	EX	-	NA	NA	NA
11	Powerex Corp.	EX	-	NA	NA	NA
12	Sierra Pacific Power Co., dba NV Energ	EX	-	NA	NA	NA
13	Clatskanie PUD	EX	153	NA	NA	NA
14	Clatskanine PUD	AD	153	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Other Transactions			NA	NA	NA
2	Acct Valuation-Clatskanie PUD Exchange		-	NA	NA	NA
3	Demand Response Avoided Energy	OS	-	NA	NA	NA
4	Grand View Solar Settlement	OS	-	NA	NA	NA
5	Absorb Dynamis Deposit	OS	-	NA	NA	NA
6	Magic West Settlement	OS	-	NA	NA	NA
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
							1
27,119				2,198,114		2,198,114	2
1,422			155,672	101,048		256,720	3
42,383				2,412,720		2,412,720	4
12,039				945,147		945,147	5
7,995				336,778		336,778	6
							7
191				15,994		15,994	8
846				70,650		70,650	9
806				67,935		67,935	10
2,798				275,144		275,144	11
765				59,218		59,218	12
57,742				2,845,057		2,845,057	13
26,718				1,683,849		1,683,849	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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)	
62,951				5,157,333		5,157,333	1
9,113				744,740		744,740	2
							3
24,727				1,070,034		1,070,034	4
3,049				219,066		219,066	5
87				6,611		6,611	6
1,256				102,284		102,284	7
3,505				374,515		374,515	8
323			17,500	16,848		34,348	9
46,846				2,796,240		2,796,240	10
							11
8,961				559,182		559,182	12
11,990				788,095		788,095	13
2,520				224,345		224,345	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Name of Respondent Idaho Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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.
9,273				578,475		578,475	1
5,536				348,952		348,952	2
4,056				282,021		282,021	3
9,571				719,158		719,158	4
694			26,796	35,090		61,886	5
566				7,980		7,980	6
1,442				111,071		111,071	7
54,532				3,256,178		3,256,178	8
3,186				278,775		278,775	9
1,133				14,863		14,863	10
22,241				1,194,553		1,194,553	11
20,273				1,114,086		1,114,086	12
-83				3,963		3,963	13
31,736				1,487,446		1,487,446	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
53,271				3,188,697		3,188,697	1
22,505				1,588,661		1,588,661	2
88,972				4,020,193		4,020,193	3
1,480				142,689		142,689	4
41,669				2,923,740		2,923,740	5
20,302				1,060,280		1,060,280	6
38,796				2,227,889		2,227,889	7
54,268				3,961,704		3,961,704	8
77,098				3,943,873		3,943,873	9
1,103				75,125		75,125	10
3,972				307,380		307,380	11
642				37,682		37,682	12
3,217				327,158		327,158	13
2,598				289,956		289,956	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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.
5,591				394,759		394,759	1
1,147				97,824		97,824	2
6,408				457,228		457,228	3
4,833				349,642		349,642	4
3,151				276,858		276,858	5
567				194,733		194,733	6
51,553				3,082,062		3,082,062	7
2,146				164,987		164,987	8
45,235				2,883,726		2,883,726	9
55,889				2,687,408		2,687,408	10
370				27,692		27,692	11
10,669				536,293		536,293	12
35,652				1,780,029		1,780,029	13
							14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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.
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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)	
2,201				58,368		58,368	1
11,436				242,889		242,889	2
3,019				257,454		257,454	3
61,116				5,000,256		5,000,256	4
8,163			486,150	367,286		853,436	5
32,307				1,706,729		1,706,729	6
826				49,393		49,393	7
1,316				70,587		70,587	8
975				76,528		76,528	9
							10
1,958				143,771		143,771	11
3,662				274,806		274,806	12
							13
3,463				177,189		177,189	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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.
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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
1,215				96,998		96,998	2
2,833				124,073		124,073	3
7,004			552,508	408,822		961,330	4
226,771				13,452,114		13,452,114	5
79,712				5,219,494		5,219,494	6
48,522				2,891,176		2,891,176	7
62,967				3,419,903		3,419,903	8
23,007				1,580,813		1,580,813	9
							10
1,314				144,674		144,674	11
2,034				141,652		141,652	12
372				27,979		27,979	13
27,042				2,182,295		2,182,295	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
32,384			1,576,498	1,836,609		3,413,107	1
269				6,285		6,285	2
							3
29,187				1,553,238		1,553,238	4
31,491				1,578,997		1,578,997	5
28,199				1,494,294		1,494,294	6
76,666				4,112,867		4,112,867	7
8,560				528,853		528,853	8
55,551				3,303,665		3,303,665	9
692				52,059		52,059	10
2,940				253,833		253,833	11
926				77,547		77,547	12
26,173				1,847,169		1,847,169	13
61,804				5,064,825		5,064,825	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-870,913		-870,913	1
				36,269		36,269	2
5,155							3
							4
4,146				165,985		165,985	5
35				1,236		1,236	6
149,080				5,177,913		5,177,913	7
					333,972	333,972	8
					32,832	32,832	9
1,075				50,700		50,700	10
					578,881	578,881	11
357				12,362		12,362	12
78,883				2,736,847		2,736,847	13
62,600				1,409,968		1,409,968	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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.
17,200				593,880		593,880	1
					-125,878	-125,878	2
29,909				1,274,332		1,274,332	3
16				566		566	4
188,825				7,428,273		7,428,273	5
					-5,816	-5,816	6
29				1,240		1,240	7
560				20,171		20,171	8
2				74		74	9
123,226				5,304,187		5,304,187	10
3,800				83,376		83,376	11
11,025				465,565		465,565	12
15				537		537	13
630				20,952		20,952	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
29,508				589,577		589,577	1
1,200				29,200		29,200	2
63				3,979		3,979	3
					-944,934	-944,934	4
22,037				738,495		738,495	5
34,806				1,143,600		1,143,600	6
					240,144	240,144	7
61,214				2,519,122		2,519,122	8
2,148				99,800		99,800	9
800				27,528		27,528	10
2,200				57,750		57,750	11
37				1,215		1,215	12
295				5,770		5,770	13
251				8,799		8,799	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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)	
12,573				354,752		354,752	1
					126,217	126,217	2
53				1,807		1,807	3
14,006				503,011		503,011	4
18,793				1,363,920		1,363,920	5
170,044				5,377,104		5,377,104	6
1,280				43,520		43,520	7
181				8,787		8,787	8
69				2,447		2,447	9
26,936				1,090,682		1,090,682	10
10,147				367,155		367,155	11
21,200				941,424		941,424	12
12				430		430	13
2,765				103,202		103,202	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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)	
39,680				883,794		883,794	1
					-193,013	-193,013	2
45				1,607		1,607	3
1,626				68,415		68,415	4
					4,381	4,381	5
95				3,770		3,770	6
2				74		74	7
1,200				57,180		57,180	8
8,056				298,124		298,124	9
4,714				173,661		173,661	10
59,700				2,007,262		2,007,262	11
134				11,685		11,685	12
1				47		47	13
77,560				4,777,539		4,777,539	14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	
300,804				16,220,616		16,220,616	1
155,530				15,509,053		15,509,053	2
978				73,213		73,213	3
643				20,007		20,007	4
					-15,465	-15,465	5
							6
	78,227						7
							8
	7,278	1,133					9
	175,839	251,815					10
	408						11
		7,571					12
	48,951	28,600					13
	67						14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

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
					382,263	382,263	2
				4,203,156		4,203,156	3
				-100,000		-100,000	4
				-150,000		-150,000	5
				-1,000,000		-1,000,000	6
							7
							8
							9
							10
							11
							12
							13
							14
3,881,443	310,770	289,119	2,815,124	211,713,115	413,584	214,941,823	

Schedule Page: 326 Line No.: 3 Column: e
Unavailable
Schedule Page: 326 Line No.: 3 Column: f
Unavailable
Schedule Page: 326.1 Line No.: 9 Column: e
Unavailable
Schedule Page: 326.1 Line No.: 9 Column: f
Unavailable
Schedule Page: 326.2 Line No.: 5 Column: e
Unavailable
Schedule Page: 326.2 Line No.: 5 Column: f
Unavailable
Schedule Page: 326.2 Line No.: 10 Column: b
Non Firm Purchases
Schedule Page: 326.3 Line No.: 2 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.
Schedule Page: 326.4 Line No.: 9 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.
Schedule Page: 326.5 Line No.: 5 Column: e
Unavailable
Schedule Page: 326.5 Line No.: 5 Column: f
Unavailable
Schedule Page: 326.5 Line No.: 13 Column: b
Non Firm Purchases
Schedule Page: 326.6 Line No.: 4 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 4 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 14 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.
Schedule Page: 326.7 Line No.: 1 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.: 1 Column: e
Unavailable
Schedule Page: 326.7 Line No.: 1 Column: f
Unavailable
Schedule Page: 326.7 Line No.: 2 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 3 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 13 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.
Schedule Page: 326.8 Line No.: 1 Column: a
Reversal of prior period accrued additional purchase power expense.
Schedule Page: 326.8 Line No.: 2 Column: a
Interest paid on prior period purchases as ordered by the IPUC.
Schedule Page: 326.8 Line No.: 3 Column: a
Difference between booked and scheduled energy
Schedule Page: 326.8 Line No.: 6 Column: b
Non Firm Purchases
Schedule Page: 326.8 Line No.: 8 Column: b

Financial Transmission Losses

Schedule Page: 326.8 Line No.: 9 Column: b

ISDA Master Agreement with Barclays Bank PLC dated March 2, 2011

Schedule Page: 326.8 Line No.: 11 Column: b

Financial Transmission Losses

Schedule Page: 326.8 Line No.: 12 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 2 Column: b

ISDA Master Agreement with Cargill Power Markets, LLC, dated June 13, 2011

Schedule Page: 326.9 Line No.: 4 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 6 Column: b

ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011

Schedule Page: 326.9 Line No.: 9 Column: b

Non-Firm Purchases

Schedule Page: 326.9 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 4 Column: b

Prudential Bache Commodities, LLC (Jefferies Bache) Futures Account Document, dated September 4, 2008

Schedule Page: 326.10 Line No.: 7 Column: b

ISDA Master Agreement with Macquarie Energy PLC dated April 12, 2011

Schedule Page: 326.10 Line No.: 12 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 14 Column: b

Non-Firm Purchases

Schedule Page: 326.11 Line No.: 2 Column: b

Financial Transmission Losses

Schedule Page: 326.11 Line No.: 3 Column: b

Non Firm Purchases

Schedule Page: 326.11 Line No.: 7 Column: b

Non-Firm Purchases

Schedule Page: 326.11 Line No.: 9 Column: b

Non Firm Purchases

Schedule Page: 326.11 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.12 Line No.: 2 Column: b

ISDA Master Agreement with Shell Energy North America dated November 1, 2009

Schedule Page: 326.12 Line No.: 3 Column: b

Non-Firm Purchases

Schedule Page: 326.12 Line No.: 5 Column: b

Financial Transmission Losses

Schedule Page: 326.12 Line No.: 7 Column: b

Non-Firm purchases

Schedule Page: 326.12 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.12 Line No.: 14 Column: b

Unavailable

Schedule Page: 326.13 Line No.: 3 Column: b

Schedule 84 Net Metering

Schedule Page: 326.13 Line No.: 4 Column: b

Schedule 88 Oregon Solar

Schedule Page: 326.13 Line No.: 7 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 8 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 9 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 10 Column: b

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	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	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
8	Cargill	Seattle City Light	Bonneville Power Administration	OS
9	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
10	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
11	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
12	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	OS
13	PacifiCorp	PacifiCorp West	PacifiCorp West	OS
14	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
15	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
16	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
17	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
18	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
19	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
20	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
21	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
23	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
24	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
25	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
26	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
27	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
28	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
29	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
30	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
31	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
32	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
33	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
34	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
2	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
3	BC Hydro Powerex	PacifiCorp West	PacifiCorp West	NF
4	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
5	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	BC Hydro Powerex	NorthWestern/PacifiCorp East	Idaho Power Company	NF
7	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	NF
9	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	SFP
10	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	NF
11	BC Hydro Powerex	Idaho Power Company	PacifiCorp West	NF
12	BC Hydro Powerex	Idaho Power Company	Sierra Pacific Power	NF
13	BC Hydro Powerex	PacifiCorp West	Idaho Power Company	NF
14	BC Hydro Powerex	PacifiCorp West	NorthWestern/PacifiCorp East	NF
15	BC Hydro Powerex	PacifiCorp West	Bonneville Power Administration	NF
16	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
17	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
18	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
19	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
21	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
24	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	SFP
25	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
26	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp West	NF
27	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	NF
28	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	SFP
29	BC Hydro Powerex	Avista	PacifiCorp East	NF
30	BC Hydro Powerex	Avista	PacifiCorp West	NF
31	BC Hydro Powerex	Avista	Sierra Pacific Power	NF
32	BC Hydro Powerex	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
33	BC Hydro Powerex	Sierra Pacific Power	PacifiCorp East	NF
34	BC Hydro Powerex	Sierra Pacific Power	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Black Hills Power	PacifiCorp West	PacifiCorp East	NF
2	Black Hills Power	PacifiCorp West	Sierra Pacific Power	NF
3	Bonneville Power Adminstration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Bonneville Power Adminstration	Bonneville Power Administration	Bonneville Power Administration	NF
5	Bonneville Power Adminstration	Bonneville Power Administration	Sierra Pacific Power	NF
6	Bonneville Power Adminstration	Avista	Bonneville Power Administration	NF
7	Bonneville Power Adminstration	Avista	Sierra Pacific Power	NF
8	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	Cargill-Alliant	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
11	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
12	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	NF
13	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	SFP
14	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	NF
15	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	SFP
16	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
18	Cargill-Alliant	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
19	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
21	Cargill-Alliant	PacifiCorp East	PacifiCorp East	NF
22	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	NF
23	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	NF
24	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	SFP
25	Cargill-Alliant	PacifiCorp West	PacifiCorp East	NF
26	Cargill-Alliant	PacifiCorp West	PacifiCorp East	SFP
27	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	NF
28	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	SFP
29	Cargill-Alliant	Idaho Power Company	Bonneville Power Administration	NF
30	Cargill-Alliant	PacifiCorp West	PacifiCorp East	NF
31	Cargill-Alliant	PacifiCorp West	NorthWestern/PacifiCorp East	NF
32	Cargill-Alliant	PacifiCorp West	Bonneville Power Administration	NF
33	Cargill-Alliant	PacifiCorp West	Avista	NF
34	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	SFP
2	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Cargill-Alliant	Bonneville Power Administration	PacifiCorp East	NF
5	Cargill-Alliant	Bonneville Power Administration	PacifiCorp East	NF
6	Cargill-Alliant	Bonneville Power Administration	Sierra Pacific Power	NF
7	Cargill-Alliant	Bonneville Power Administration	Sierra Pacific Power	SFP
8	Cargill-Alliant	Avista	PacifiCorp East	NF
9	Cargill-Alliant	Avista	PacifiCorp East	SFP
10	Cargill-Alliant	Avista	PacifiCorp West	NF
11	Cargill-Alliant	Avista	Sierra Pacific Power	NF
12	Cargill-Alliant	Avista	Sierra Pacific Power	SFP
13	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
14	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	SFP
15	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
16	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
17	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	NF
18	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	NF
19	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
20	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	NF
21	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	SFP
22	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	LFP
23	Cargill-Alliant	Sierra Pacific Power	Avista	NF
24	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	NF
25	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	SFP
26	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	NF
27	Cargill-Alliant	Idaho Power Company	Bonneville Power Administration	SFP
28	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
29	Iberdrola Energy	PacifiCorp East	Sierra Pacific Power	NF
30	Iberdrola Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
31	Iberdrola Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
32	Iberdrola Energy	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Iberdrola Energy	PacifiCorp East	PacifiCorp East	NF
34	Iberdrola Energy	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)
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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	Iberdrola Energy	PacifiCorp West	PacifiCorp East	NF
2	Iberdrola Energy	PacifiCorp West	Sierra Pacific Power	NF
3	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
4	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
5	Iberdrola Energy	Idaho Power Company	Sierra Pacific Power	NF
6	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
7	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
8	Iberdrola Energy	Bonneville Power Administration	Sierra Pacific Power	NF
9	Iberdrola Energy	Avista	PacifiCorp East	NF
10	Iberdrola Energy	Avista	Sierra Pacific Power	NF
11	Iberdrola Energy	Sierra Pacific Power	PacifiCorp East	NF
12	Iberdrola Energy	Sierra Pacific Power	Bonneville Power Administration	NF
13	Macquarie Energy	PacifiCorp East	Bonneville Power Administration	NF
14	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
15	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Morgan Stanley Captial Group	PacifiCorp East	PacifiCorp East	NF
17	Morgan Stanley Captial Group	PacifiCorp East	Bonneville Power Administration	NF
18	Morgan Stanley Captial Group	PacifiCorp East	Sierra Pacific Power	NF
19	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	Morgan Stanley Captial Group	PacifiCorp East	PacifiCorp East	NF
24	Morgan Stanley Captial Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
25	Morgan Stanley Captial Group	PacifiCorp East	Bonneville Power Administration	NF
26	Morgan Stanley Captial Group	PacifiCorp East	Sierra Pacific Power	NF
27	Morgan Stanley Captial Group	PacifiCorp West	PacifiCorp East	NF
28	Morgan Stanley Captial Group	Idaho Power Company	PacifiCorp East	NF
29	Morgan Stanley Captial Group	Idaho Power Company	PacifiCorp East	SFP
30	Morgan Stanley Captial Group	Idaho Power Company	PacifiCorp East	NF
31	Morgan Stanley Captial Group	Idaho Power Company	Sierra Pacific Power	NF
32	Morgan Stanley Captial Group	PacifiCorp West	PacifiCorp East	NF
33	Morgan Stanley Captial Group	PacifiCorp West	PacifiCorp East	NF
34	Morgan Stanley Captial Group	PacifiCorp West	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Morgan Stanley Captial Group	PacifiCorp West	Sierra Pacific Power	NF
2	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
4	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
5	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Morgan Stanley Captial Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Morgan Stanley Captial Group	Bonneville Power Administration	PacifiCorp East	NF
8	Morgan Stanley Captial Group	Bonneville Power Administration	PacifiCorp East	NF
9	Morgan Stanley Captial Group	Bonneville Power Administration	Avista	NF
10	Morgan Stanley Captial Group	Bonneville Power Administration	Sierra Pacific Power	NF
11	Morgan Stanley Captial Group	Avista	PacifiCorp East	NF
12	Morgan Stanley Captial Group	Avista	PacifiCorp East	NF
13	Morgan Stanley Captial Group	Avista	Sierra Pacific Power	NF
14	Morgan Stanley Captial Group	Sierra Pacific Power	PacifiCorp East	NF
15	Morgan Stanley Captial Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
16	Morgan Stanley Captial Group	Sierra Pacific Power	PacifiCorp East	NF
17	Morgan Stanley Captial Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
18	Morgan Stanley Captial Group	Sierra Pacific Power	Bonneville Power Administration	NF
19	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
20	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	LFP
21	Pacificorp Power Marketing	PacifiCorp East	Bonneville Power Administration	NF
22	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
23	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
24	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
25	Pacificorp Power Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
26	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
27	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
28	Pacificorp Power Marketing	PacifiCorp West	Bonneville Power Administration	NF
29	Pacificorp Power Marketing	Idaho Power Company	Sierra Pacific Power	NF
30	Pacificorp Power Marketing	Idaho Power Company	Sierra Pacific Power	SFP
31	Pacificorp Power Marketing	PacifiCorp West	Idaho Power Company	NF
32	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
33	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
34	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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	Pacificorp Power Marketing	Idaho Power Company	NorthWestern/PacifiCorp East	NF
2	Pacificorp Power Marketing	Idaho Power Company	Idaho Power Company	LFP
3	Pacificorp Power Marketing	Idaho Power Company	Idaho Power Company	NF
4	Pacificorp Power Marketing	Idaho Power Company	Bonneville Power Administration	NF
5	Pacificorp Power Marketing	Idaho Power Company	Sierra Pacific Power	NF
6	Pacificorp Power Marketing	Idaho Power Company	NorthWestern/PacifiCorp East	NF
7	Pacificorp Power Marketing	Avista	PacifiCorp West	NF
8	Porland General Electric	PacifiCorp East	NorthWestern/PacifiCorp East	NF
9	Porland General Electric	PacifiCorp East	Idaho Power Company	NF
10	Porland General Electric	PacifiCorp East	Bonneville Power Administration	NF
11	Porland General Electric	Idaho Power Company	PacifiCorp East	NF
12	Porland General Electric	Idaho Power Company	Sierra Pacific Power	NF
13	Porland General Electric	Bonneville Power Administration	PacifiCorp East	NF
14	Porland General Electric	Bonneville Power Administration	PacifiCorp East	NF
15	Porland General Electric	Bonneville Power Administration	Sierra Pacific Power	NF
16	Porland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF
17	PPL Energy Plus	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
18	PPL Energy Plus	Sierra Pacific Power	PacifiCorp East	NF
19	Rainbow Energy Marketing	PacifiCorp East	Avista	NF
20	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
21	Rainbow Energy Marketing	PacifiCorp West	NorthWestern/PacifiCorp East	NF
22	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp West	NF
23	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
24	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
25	Rainbow Energy Marketing	Avista	Sierra Pacific Power	SFP
26	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
27	Shell Energy	PacifiCorp East	Sierra Pacific Power	NF
28	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
29	Shell Energy	PacifiCorp East	Sierra Pacific Power	NF
30	Shell Energy	PacifiCorp East	Sierra Pacific Power	SFP
31	Shell Energy	Idaho Power Company	Sierra Pacific Power	NF
32	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
33	Shell Energy	PacifiCorp West	Bonneville Power Administration	NF
34	Shell Energy	PacifiCorp West	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
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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.
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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	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
2	Shell Energy	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
3	Shell Energy	Bonneville Power Administration	Sierra Pacific Power	NF
4	Shell Energy	Bonneville Power Administration	Sierra Pacific Power	SFP
5	Shell Energy	Avista	Sierra Pacific Power	NF
6	Shell Energy	Avista	Sierra Pacific Power	SFP
7	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
8	Shell Energy	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
9	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
10	Shell Energy	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
11	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
12	Shell Energy	Idaho Power Company	PacifiCorp East	NF
13	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
14	Shell Energy	Idaho Power Company	Sierra Pacific Power	NF
15	Shell Energy	Idaho Power Company	PacifiCorp East	NF
16	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
17	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
18	Sierra Pacific Power Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
20	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
21	Sierra Pacific Power Marketing	Idaho Power Company	Sierra Pacific Power	NF
22	Sierra Pacific Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
23	Sierra Pacific Power Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
24	Sierra Pacific Power Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
25	Sierra Pacific Power Marketing	Avista	Sierra Pacific Power	NF
26	Sierra Pacific Power Marketing	Avista	Sierra Pacific Power	SFP
27	Sierra Pacific Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
28	Sierra Pacific Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
29	Sierra Pacific Power Marketing	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
30	Sierra Pacific Power Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
31	Southern California Edison	Bonneville Power Administration	PacifiCorp East	NF
32	Tenaska	NorthWestern/PacifiCorp East	Avista	NF
33	Tenaska	PacifiCorp West	NorthWestern/PacifiCorp East	NF
34	The Energy Authority	NorthWestern/PacifiCorp East	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
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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	The Energy Authority	Bonneville Power Administration	PacifiCorp East	NF
2	The Energy Authority	Bonneville Power Administration	PacifiCorp East	NF
3	Transalta Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
4	Transalta Energy Marketing	PacifiCorp East	Idaho Power Company	NF
5	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
6	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
7	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	Transalta Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	Transalta Energy Marketing	PacifiCorp East	PacifiCorp East	NF
10	Transalta Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
11	Transalta Energy Marketing	Idaho Power Company	PacifiCorp East	NF
12	Transalta Energy Marketing	Idaho Power Company	Sierra Pacific Power	NF
13	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
14	Transalta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
15	Transalta Energy Marketing	Avista	Sierra Pacific Power	NF
16	Transalta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
17	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5				341,460	341,460	1
5						2
5				294,562	294,562	3
5						4
5				1,294,517	1,294,517	5
5						6
Legacy	Minidoka, Idaho	Various in Idaho		9,105	9,105	7
5				215,463	215,463	8
5				2,159	2,159	9
5						10
Legacy	LaGrande, Oregon	Various in Idaho		17,812	17,812	11
5	JEFF	IPCO		5,766	5,766	12
Legacy	JBSN	ENPR				13
Legacy	JBSN	ENPR				14
5	BORA	BPAT.NWMT		3,247	3,247	15
5	BORA	ENPR		51	51	16
5	BORA	HMWY		3,387	3,387	17
5	BORA	JEFF		131	131	18
5	BORA	LAGRANDE		9,051	9,051	19
5	BORA	M345		60	60	20
5	BPAT.NWMT	BORA		649	649	21
5	BPAT.NWMT	BORA		19,962	19,962	22
5	BPAT.NWMT	BRDY		508	508	23
5	BPAT.NWMT	JBSN		206	206	24
5	BPAT.NWMT	LAGRANDE		30	30	25
5	BPAT.NWMT	M345		675	675	26
5	BRDY	BORA		869	869	27
5	BRDY	BPAT.NWMT		2,221	2,221	28
5	BRDY	ENPR		14	14	29
5	BRDY	HMWY		526	526	30
5	BRDY	JBSN		30	30	31
5	BRDY	LAGRANDE		3,794	3,794	32
5	BRDY	M345		2,472	2,472	33
5	ENPR	BORA		79,067	79,067	34
			0	**6,358,859**	**6,358,859**	

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.
5	ENPR	BORA		129,029	129,029	1
5	ENPR	BRDY		1,140	1,140	2
5	ENPR	JBSN		45	45	3
5	ENPR	M345		482	482	4
5	GSHN	BRDY		5	5	5
5	GSHN	HMWY		96	96	6
5	GSHN	LAGRANDE		1,817	1,817	7
5	HMWY	BORA		138,062	138,062	8
5	HMWY	BORA		77,534	77,534	9
5	HMWY	BRDY		632	632	10
5	HMWY	JBSN		843	843	11
5	HMWY	M345		6,744	6,744	12
5	JBSN	HMWY		722	722	13
5	JBSN	JEFF		336	336	14
5	JBSN	LAGRANDE		879	879	15
5	JBSN	M345		48	48	16
5	JBWT	LAGRANDE		123	123	17
5	JEFF	BPAT.NWMT		29	29	18
5	JEFF	BRDY		25	25	19
5	JEFF	JBSN		5	5	20
5	JEFF	LAGRANDE		371	371	21
5	JEFF	M345		43	43	22
5	LAGRANDE	BORA		8,691	8,691	23
5	LAGRANDE	BORA		1,002	1,002	24
5	LAGRANDE	BRDY		142	142	25
5	LAGRANDE	JBSN		36	36	26
5	LAGRANDE	M345		6,908	6,908	27
5	LAGRANDE	M345		102	102	28
5	LOLO	BORA		106	106	29
5	LOLO	JBSN		196	196	30
5	LOLO	M345		209	209	31
5	M345	BPAT.NWMT		100	100	32
5	M345	BRDY		59	59	33
5	M345	LAGRANDE		818	818	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
5	JBSN	BORA		10	10	1
5	JBSN	M345		337	337	2
5	BPAT.NWMT	M345		20	20	3
5	LAGRANDE	LAGRANDE		11,011	11,011	4
5	LAGRANDE	M345		16,120	16,120	5
5	LOLO	LAGRANDE		8,589	8,589	6
5	LOLO	M345		2,174	2,174	7
5	AVAT.NWMT	M345		430	430	8
5	BORA	BPAT.NWMT		225	225	9
5	BORA	ENPR		975	975	10
5	BORA	JBSN		565	565	11
5	BORA	LAGRANDE		8,688	8,688	12
5	BORA	LAGRANDE		1,072	1,072	13
5	BORA	M345		14,083	14,083	14
5	BORA	M345		8,343	8,343	15
5	BPAT.NWMT	BORA		887	887	16
5	BPAT.NWMT	BORA		9,473	9,473	17
5	BPAT.NWMT	LAGRANDE		392	392	18
5	BPAT.NWMT	M345		11,394	11,394	19
5	BPAT.NWMT	M345		12,907	12,907	20
5	BRDY	BORA		38	38	21
5	BRDY	LAGRANDE		34	34	22
5	BRDY	M345		1,636	1,636	23
5	BRDY	M345		64	64	24
5	ENPR	BORA		7,987	7,987	25
5	ENPR	BORA		17,665	17,665	26
5	ENPR	M345		3,678	3,678	27
5	ENPR	M345		8,868	8,868	28
5	IPCOGEN	LAGRANDE		50	50	29
5	JBSN	BORA		187	187	30
5	JBSN	BPAT.NWMT		211	211	31
5	JBSN	LAGRANDE		1,303	1,303	32
5	JBSN	LOLO		1,600	1,600	33
5	JBSN	M345		333	333	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
5	JBSN	M345		475	475	1
5	JEFF	BORA		8	8	2
5	JEFF	M345		2,697	2,697	3
5	LAGRANDE	BORA		1,359	1,359	4
5	LAGRANDE	BRDY		117	117	5
5	LAGRANDE	M345		27,478	27,478	6
5	LAGRANDE	M345		2,866	2,866	7
5	LOLO	BORA		6,693	6,693	8
5	LOLO	BORA		2,256	2,256	9
5	LOLO	JBSN		192	192	10
5	LOLO	M345		11,210	11,210	11
5	LOLO	M345		2,544	2,544	12
5	LYPK	BORA		6,848	6,848	13
5	LYPK	BORA		17,825	17,825	14
5	LYPK	BPAT.NWMT		312	312	15
5	LYPK	BRDY		143	143	16
5	LYPK	ENPR		32	32	17
5	LYPK	JBSN		50	50	18
5	LYPK	JEFF		55	55	19
5	LYPK	LAGRANDE		3,234	3,234	20
5	LYPK	LAGRANDE		216	216	21
5	LYPK	LAGRANDE		19,389	19,389	22
5	LYPK	LOLO		20	20	23
5	LYPK	M345		14,454	14,454	24
5	LYPK	M345		152,346	152,346	25
5	M345	LAGRANDE		25	25	26
5	OBBLPR	LAGRANDE		800	800	27
5	BORA	LAGRANDE		636	636	28
5	BORA	M345		5	5	29
5	BPAT.NWMT	BORA		67	67	30
5	BPAT.NWMT	BRDY		50	50	31
5	BPAT.NWMT	M345		1,230	1,230	32
5	BRDY	BORA		50	50	33
5	BRDY	M345		50	50	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
5	ENPR	BORA		19	19	1
5	ENPR	M345		600	600	2
5	HMWY	BORA		15,921	15,921	3
5	HMWY	BRDY		630	630	4
5	HMWY	M345		4,987	4,987	5
5	LAGRANDE	BORA		13,190	13,190	6
5	LAGRANDE	BRDY		240	240	7
5	LAGRANDE	M345		7,297	7,297	8
5	LOLO	BORA		30	30	9
5	LOLO	M345		250	250	10
5	M345	BORA		150	150	11
5	M345	LAGRANDE		59	59	12
5	BORA	LAGRANDE		68	68	13
5	AVAT.NWMT	BORA		236	236	14
5	AVAT.NWMT	M345		973	973	15
5	BORA	BRDY		44	44	16
5	BORA	LAGRANDE		804	804	17
5	BORA	M345		6,293	6,293	18
5	BPAT.NWMT	BORA		25	25	19
5	BPAT.NWMT	BRDY		14	14	20
5	BPAT.NWMT	LAGRANDE		81	81	21
5	BPAT.NWMT	M345		1,195	1,195	22
5	BRDY	BORA		838	838	23
5	BRDY	BPAT.NWMT		90	90	24
5	BRDY	LAGRANDE		607	607	25
5	BRDY	M345		2,819	2,819	26
5	ENPR	BORA		408	408	27
5	HMWY	BORA		10,138	10,138	28
5	HMWY	BORA		11,279	11,279	29
5	HMWY	BRDY		200	200	30
5	HMWY	M345		1,776	1,776	31
5	JBSN	BORA		2,303	2,303	32
5	JBSN	BRDY		142	142	33
5	JBSN	LAGRANDE		158	158	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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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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.
5	JBSN	M345		1,195	1,195	1
5	JEFF	BORA		118,219	118,219	2
5	JEFF	BORA		1,146	1,146	3
5	JEFF	BRDY		760	760	4
5	JEFF	LAGRANDE		1,141	1,141	5
5	JEFF	M345		11,558	11,558	6
5	LAGRANDE	BORA		4,374	4,374	7
5	LAGRANDE	BRDY		1,050	1,050	8
5	LAGRANDE	LOLO		51	51	9
5	LAGRANDE	M345		11,107	11,107	10
5	LOLO	BORA		253	253	11
5	LOLO	BRDY		24	24	12
5	LOLO	M345		1,701	1,701	13
5	M345	BORA		227	227	14
5	M345	BPAT.NWMT		352	352	15
5	M345	BRDY		75	75	16
5	M345	JEFF		100	100	17
5	M345	LAGRANDE		239	239	18
5	BORA	ENPR		3,109	3,109	19
5	BORA	KPRT		1,123,100	1,123,100	20
5	BORA	LAGRANDE		3,867	3,867	21
5	BORA	M345		776	776	22
5	BRDY	BORA		134	134	23
5	BRDY	BRDY		2,434	2,434	24
5	BRDY	GSHN		190	190	25
5	BRDY	KPRT		2,000	2,000	26
5	ENPR	BORA		190,648	190,648	27
5	ENPR	LAGRANDE		83	83	28
5	HMWY	M345		136	136	29
5	HMWY	M345		1,404	1,404	30
5	JBSN	KPRT		34	34	31
5	JBWT	BRDY		9,260	9,260	32
5	JBWT	BRDY		424,261	424,261	33
5	JBWT	ENPR		1,239	1,239	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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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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.
5	JBWT	GSHN		1,208	1,208	1
5	JBWT	HMWY		650,125	650,125	2
5	JBWT	KPRT		255,016	255,016	3
5	JBWT	LAGRANDE		26,118	26,118	4
5	JBWT	M345		56	56	5
5	KPRT	GSHN		3,410	3,410	6
5	LOLO	ENPR		16,495	16,495	7
5	BORA	BPAT.NWMT		100	100	8
5	BORA	HMWY		178	178	9
5	BORA	LAGRANDE		1,041	1,041	10
5	HMWY	BORA		3,827	3,827	11
5	HMWY	M345		355	355	12
5	LAGRANDE	BORA		1,237	1,237	13
5	LAGRANDE	BRDY		54	54	14
5	LAGRANDE	M345		914	914	15
5	M345	LAGRANDE		368	368	16
5	JEFF	LAGRANDE		49	49	17
5	M345	BRDY		30	30	18
5	BORA	LOLO		400	400	19
5	BRDY	M345		104	104	20
5	JBSN	JEFF		221	221	21
5	JEFF	JBSN		40	40	22
5	JEFF	M345		259	259	23
5	LOLO	BORA		621	621	24
5	LOLO	M345		12,319	12,319	25
5	BORA	LAGRANDE		69	69	26
5	BORA	M345		200	200	27
5	BRDY	LAGRANDE		874	874	28
5	BRDY	M345		9,548	9,548	29
5	BRDY	M345		13,755	13,755	30
5	HMWY	M345		1,855	1,855	31
5	IPCOGEN	LAGRANDE		91	91	32
5	JBSN	LAGRANDE		30	30	33
5	JBSN	M345		232	232	34
			0	**6,358,859**	**6,358,859**	

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)	
5	JEFF	LAGRANDE		520	520	1
5	JEFF	M345		7,340	7,340	2
5	LAGRANDE	M345		16,086	16,086	3
5	LAGRANDE	M345		1,367	1,367	4
5	LOLO	M345		84,262	84,262	5
5	LOLO	M345		16,143	16,143	6
5	LYPK	LAGRANDE		769	769	7
5	M345	BPAT.NWMT		15	15	8
5	M345	BRDY		105	105	9
5	M345	JEFF		104	104	10
5	M345	LAGRANDE		2,686	2,686	11
5	MDSK	BRDY		90	90	12
5	MDSK	LAGRANDE		532	532	13
5	MDSK	M345		30	30	14
5	OBBLPR	BRDY		66	66	15
5	OBBLPR	LAGRANDE		1,005	1,005	16
5	BORA	M345		3,468	3,468	17
5	BPAT.NWMT	M345		1,040	1,040	18
5	BRDY	M345		3,722	3,722	19
5	BRDY	M345		608	608	20
5	HMWY	M345		6,537	6,537	21
5	JBSN	M345		2,622	2,622	22
5	JEFF	M345		5,084	5,084	23
5	LAGRANDE	M345		2,085	2,085	24
5	LOLO	M345		18,720	18,720	25
5	LOLO	M345		22,680	22,680	26
5	M345	BORA		125	125	27
5	M345	BRDY		475	475	28
5	M345	JEFF		85	85	29
5	M345	LAGRANDE		625	625	30
5	LAGRANDE	BORA		300	300	31
5	BPAT.NWMT	LOLO		75	75	32
5	JBSN	AVAT.NWMT		37	37	33
5	BPAT.NWMT	BRDY		484	484	34
			0	**6,358,859**	**6,358,859**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
5	LAGRANDE	BORA		143	143	1
5	LAGRANDE	BRDY		120	120	2
5	BORA	BPAT.NWMT		84	84	3
5	BORA	HMWY		2,886	2,886	4
5	BORA	LAGRANDE		1,642	1,642	5
5	BPAT.NWMT	BORA		90	90	6
5	BPAT.NWMT	BRDY		90	90	7
5	BPAT.NWMT	M345		143	143	8
5	BRDY	BORA		31	31	9
5	BRDY	M345		40	40	10
5	HMWY	BORA		6,702	6,702	11
5	HMWY	M345		1,654	1,654	12
5	LAGRANDE	BORA		8,828	8,828	13
5	LAGRANDE	M345		5,307	5,307	14
5	LOLO	M345		125	125	15
5	M345	LAGRANDE		379	379	16
5	BORA	M345		17,139	17,139	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**6,358,859**	**6,358,859**	

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.
1,172,900	-135,451		1,037,449	1
-5,348			-5,348	2
1,336,686	-32,678		1,304,008	3
-3,392			-3,392	4
4,344,812	345,130		4,689,942	5
-19,386			-19,386	6
	14,750		14,750	7
	201,364		201,364	8
7,130	1,339		8,469	9
-32			-32	10
54,640			54,640	11
	5,877		5,877	12
	9,009		9,009	13
	67,248		67,248	14
	14,773		14,773	15
	232		232	16
	15,409		15,409	17
	596		596	18
	41,178		41,178	19
	273		273	20
	2,953		2,953	21
	90,819		90,819	22
	2,311		2,311	23
	937		937	24
	136		136	25
	3,071		3,071	26
	3,954		3,954	27
	10,105		10,105	28
	64		64	29
	2,393		2,393	30
	136		136	31
	17,261		17,261	32
	11,247		11,247	33
	359,723		359,723	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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.
	587,029		587,029	1
	5,187		5,187	2
	205		205	3
	2,193		2,193	4
	23		23	5
	437		437	6
	8,267		8,267	7
	628,126		628,126	8
	352,748		352,748	9
	2,875		2,875	10
	3,835		3,835	11
	30,682		30,682	12
	3,285		3,285	13
	1,529		1,529	14
	3,999		3,999	15
	218		218	16
	560		560	17
	132		132	18
	114		114	19
	23		23	20
	1,688		1,688	21
	196		196	22
	39,541		39,541	23
	4,559		4,559	24
	646		646	25
	164		164	26
	31,428		31,428	27
	464		464	28
	482		482	29
	892		892	30
	951		951	31
	455		455	32
	268		268	33
	3,721		3,721	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
	110		110	1
	3,720		3,720	2
	79		79	3
	43,326		43,326	4
	63,429		63,429	5
	33,796		33,796	6
	8,554		8,554	7
	2,521		2,521	8
	1,319		1,319	9
	5,715		5,715	10
	3,312		3,312	11
	50,930		50,930	12
	6,284		6,284	13
	82,555		82,555	14
	48,907		48,907	15
	5,200		5,200	16
	55,531		55,531	17
	2,298		2,298	18
	66,792		66,792	19
	75,662		75,662	20
	223		223	21
	199		199	22
	9,590		9,590	23
	375		375	24
	46,820		46,820	25
	103,553		103,553	26
	21,561		21,561	27
	51,985		51,985	28
	293		293	29
	1,096		1,096	30
	1,237		1,237	31
	7,638		7,638	32
	9,379		9,379	33
	1,952		1,952	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,784		2,784	1
	47		47	2
	15,810		15,810	3
	7,967		7,967	4
	686		686	5
	161,077		161,077	6
	16,801		16,801	7
	39,235		39,235	8
	13,225		13,225	9
	1,125		1,125	10
	65,714		65,714	11
	14,913		14,913	12
	40,143		40,143	13
	104,491		104,491	14
	1,829		1,829	15
	838		838	16
	188		188	17
	293		293	18
	322		322	19
	18,958		18,958	20
	1,266		1,266	21
	113,659		113,659	22
	117		117	23
	84,730		84,730	24
	893,060		893,060	25
	146		146	26
	4,690		4,690	27
	2,543		2,543	28
	20		20	29
	268		268	30
	200		200	31
	4,918		4,918	32
	200		200	33
	200		200	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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.
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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.
	76		76	1
	2,399		2,399	2
	63,666		63,666	3
	2,519		2,519	4
	19,942		19,942	5
	52,745		52,745	6
	960		960	7
	29,180		29,180	8
	120		120	9
	1,000		1,000	10
	600		600	11
	236		236	12
	198		198	13
	893		893	14
	3,683		3,683	15
	166		166	16
	3,043		3,043	17
	23,820		23,820	18
	95		95	19
	53		53	20
	307		307	21
	4,523		4,523	22
	3,172		3,172	23
	341		341	24
	2,298		2,298	25
	10,670		10,670	26
	1,544		1,544	27
	38,374		38,374	28
	42,693		42,693	29
	757		757	30
	6,722		6,722	31
	8,717		8,717	32
	537		537	33
	598		598	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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.
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11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,523		4,523	1
	447,475		447,475	2
	4,338		4,338	3
	2,877		2,877	4
	4,319		4,319	5
	43,749		43,749	6
	16,556		16,556	7
	3,974		3,974	8
	193		193	9
	42,042		42,042	10
	958		958	11
	91		91	12
	6,439		6,439	13
	859		859	14
	1,332		1,332	15
	284		284	16
	379		379	17
	905		905	18
	15,126		15,126	19
				20
	18,814		18,814	21
	3,775		3,775	22
	652		652	23
	11,842		11,842	24
	924		924	25
	9,730		9,730	26
	927,542		927,542	27
	404		404	28
	662		662	29
	6,831		6,831	30
	165		165	31
	45,052		45,052	32
	2,064,118		2,064,118	33
	6,028		6,028	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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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.
	5,877		5,877	1
	3,162,993		3,162,993	2
	1,240,706		1,240,706	3
	127,069		127,069	4
	272		272	5
	16,590		16,590	6
	80,252		80,252	7
	398		398	8
	708		708	9
	4,143		4,143	10
	15,232		15,232	11
	1,413		1,413	12
	4,924		4,924	13
	215		215	14
	3,638		3,638	15
	1,465		1,465	16
	155		155	17
	95		95	18
	1,930		1,930	19
	502		502	20
	1,067		1,067	21
	193		193	22
	1,250		1,250	23
	2,997		2,997	24
	59,451		59,451	25
	282		282	26
	817		817	27
	3,570		3,570	28
	39,004		39,004	29
	56,190		56,190	30
	7,578		7,578	31
	372		372	32
	123		123	33
	948		948	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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.
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11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,124		2,124	1
	29,984		29,984	2
	65,712		65,712	3
	5,584		5,584	4
	344,220		344,220	5
	65,945		65,945	6
	3,141		3,141	7
	61		61	8
	429		429	9
	425		425	10
	10,972		10,972	11
	368		368	12
	2,173		2,173	13
	123		123	14
	270		270	15
	4,105		4,105	16
	12,979		12,979	17
	3,892		3,892	18
	13,929		13,929	19
	2,275		2,275	20
	24,464		24,464	21
	9,812		9,812	22
	19,026		19,026	23
	7,803		7,803	24
	70,057		70,057	25
	84,877		84,877	26
	468		468	27
	1,778		1,778	28
	318		318	29
	2,339		2,339	30
	6,243		6,243	31
	278		278	32
	137		137	33
	1,796		1,796	34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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 (I), 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.
	530		530	1
	445		445	2
	376		376	3
	12,914		12,914	4
	7,347		7,347	5
	403		403	6
	403		403	7
	640		640	8
	139		139	9
	179		179	10
	29,988		29,988	11
	7,401		7,401	12
	39,501		39,501	13
	23,746		23,746	14
	559		559	15
	1,696		1,696	16
	62,489		62,489	17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
6,888,010	**15,048,372**	**0**	**21,936,382**	

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

Open Access Transmission Tariff, Volume 5, first revision.

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

Adjustment to load ratio share June 2012 thru March 2013

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31,2014. 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

Adjustment to load ratio share June 2012 thru March 2013.

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, 2008.

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

Adjustment to Load Ratio Share June 2012 thru March 2013.

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

Legacy contract prior to the Open Access Transmission Tariff.

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

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

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

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

Schedule Page: 328 Line No.: 9 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.: 10 Column: h

Adjustment to Load Ratio Share June 2012 thru March 2013.

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

Legacy contract prior to the Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 11 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.: 12 Column: h

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

Schedule Page: 328 Line No.: 13 Column: e

Legacy contract prior to the Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 14 Column: e

Legacy contract prior to the Open Access Transmission Tariff.

Schedule Page: 328.5 Line No.: 20 Column: h

Legacy agreement providing OATT-like service, but billed under 454 Facilities revenue.

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	24,533	24,533		143,503		143,503
2	Avista Corp-WWP Div	SFP	275,688	275,688		1,107,259		1,107,259
3	Avista Corp-WWP Div	AD				-114		-114
4	Bonneville Power Admin	LFP	827,013	827,013		3,325,332		3,325,332
5	Bonneville Power Admin	SFP	551	551		631		631
6	Bonneville Power Admin	OS				-1,974		-1,974
7	Bonneville Power Admin	OS					12,404	12,404
8	Cargill Power Markets	OS					-20,286	-20,286
9	Grant County PUD	SFP	43,027	43,027			121,440	121,440
10	Ierdrola Renewables	OS					-593	-593
11	Morgan Stanley Capital	OS					-1,192	-1,192
12	Northwestern Energy	LFP	21,302	21,302		199,600		199,600
13	NorthWesern Energy	NF	2,526	2,526		14,144		14,144
14	NorthWestern Energy	SFP	1,017	1,017		5,227		5,227
15	PacifiCorp Inc.	LFP	128,264	128,264		877,796		877,796
16	PacifiCorp Inc.	NF	17,342	17,342		77,105		77,105
	TOTAL		1,367,479	1,367,479		5,706,591	-69,313	5,637,278

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	SFP	2,610	2,610		13,938		13,938
2	PaifiCorp Inc.	OS					-105	-105
3	PacifiCorp Inc	OS				-130,856		-130,856
4	Powerex Corp.	OS	205	205			-180,981	-180,981
5	Puget Sound Energy, Inc	SFP	11,484	11,484		15,099		15,099
6	Seattle City Light	SFP	9,645	9,645		45,050		45,050
7	Sierra Pacific Power Co	NF	2,272	2,272		14,851		14,851
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,367,479	1,367,479		5,706,591	-69,313	5,637,278

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

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

Schedule Page: 332 Line No.: 6 Column: a
Prior year adjustment

Schedule Page: 332 Line No.: 7 Column: a
Reserves Provided

Schedule Page: 332 Line No.: 8 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 10 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 11 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 12 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 15 Column: b
Contract Expiration Date 05/31/2014

Schedule Page: 332.1 Line No.: 2 Column: a
Unreserved Use Refund

Schedule Page: 332.1 Line No.: 3 Column: a
2012/2013 PTP True Up - PacifiCorp

Schedule Page: 332.1 Line No.: 4 Column: a
Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	418,795
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,317,917
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	352,652
6	Robert Tinstman	125,185
7	Stephen Allred	68,310
8	Richard Dahl	83,655
9	Ronald Jibson	19,305
10	Judith Johansen	38,268
11	Dennis Johnson	47,520
12	Christine King	81,029
13	Gary Michael	60,555
14	Jan Packwood	54,945
15	Joan Smith	77,098
16	Richard Reiten	31,185
17	Thomas Wilford	65,599
18		
19	Associated Taxpayers of Idaho	23,000
20	Association of Idaho Cities	2,300
21	Boston College Center for Corporations	5,000
22	Corporate Executive Board	41,750
23	Easter Oregon Visitors Assoc	1,500
24	Idaho Association of Commerce and Industry	14,000
25	Idaho Assciation of Counties	1,346
26	Idaho Council of Goverments	1,000
27	Idaho Office of Energy Resources	2,000
28	Idaho Technology Council	10,000
29	National Association of Directors	6,175
30	National Hydropower Asswociation	32,507
31	North American Energy Standard	7,000
32	Northwest Power Pool	156,807
33	Pacific Northwest Utilities	38,869
34	Western Electricity Coordinating Council	897,334
35	Western Energy Institute	30,280
36	Wyoming Taxpayers Association	1,600
37	Misc Memberships under $1000 (3)	875
38		
39		
40		
41		
42	Chambers of Commerce & Other Civic Organizations	131,010
43		
44		
45		
46	TOTAL	4,246,371

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

Recipient	Purpose	Amount
Broadridge Financial Solutions	Proxy & Bulletin	$ 48,906
CEB	Misc Expense	41,116
Deutsche Bank	Broker Fees	33,874
Rate Related Amortization	Misc Expense	230,656
Stock Based Compensation	Misc Expense	603,819
Thompson Financial/Carson	Analyst Service	47,072
Wells Fargo Shareowner Service	Mgmt Services	99,355
Moody's	Mgmt Services	31,382
Esource	Mgmt Services	11,467
Operations Accrual		108,946
Miscellaneous		61,324

Total		$1,317,917
		==========

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			7,611,634		7,611,634
2	Steam Production Plant	23,764,277	587,012			24,351,289
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	13,528,926				13,528,926
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	16,976,100				16,976,100
7	Transmission Plant	19,134,690				19,134,690
8	Distribution Plant	38,905,749				38,905,749
9	Regional Transmission and Market Operation					
10	General Plant	9,176,449				9,176,449
11	Common Plant-Electric					
12	TOTAL	121,486,191	587,012	7,611,634		129,684,837

B. Basis for Amortization Charges

Acct 404	Balance 1/1/13	2013 Amortization	Balance 12/31/13	Remaining months
(1)	60,000	12,000	48,000	48
(2)	11,430,888	545,446	10,885,442	-
(3)	5,626,910	189,418	5,468,500	345
(4)	15,481,590	6,562,164	19,158,412	-
(5)	4,323,796	287,899	4,035,897	180
(6)	217,873	8,026	209,847	-
(7)		6,680	618,074	-
	------------------	-------------	-------------	
Total	37,141,058	7,611,634	40,424,173	

(1) Shoshone-Bannock Tribe License & Use Agreement (Termination date December 31, 2023).
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period).
(3) Swan Falls Relicensing (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 Complianc Costs (Termination date will be expirtion date of the FERC Licenses).

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	633	75.00		3.69	R4.0	20.20
13	311.00	147,608	100.00	-10.00	1.79	S1.0	21.30
14	312.10	81,866	60.00	-5.00	1.41	R3.0	21.80
15	312.20	488,479	60.00	-5.00	2.77	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.32	R3.0	7.90
17	314.00	157,130	45.00	-5.00	3.15	S1.0	19.40
18	315.00	69,527	60.00		1.49	S1.5	19.80
19	316.00	13,009	45.00	-5.00	3.81	R0.5	19.00
20	316.10	84	12.00	15.00	8.83	L2.0	6.30
21	316.40	243	12.00	15.00	0.69	L2.0	7.90
22	316.50	83	12.00	15.00	3.19	L2.0	5.10
23	316.60	533	20.00	15.00	6.14	L2.0	18.00
24	316.70	550	20.00	15.00	1.97	L2.0	14.40
25	316.80	1,909	20.00	30.00	2.94	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	10,046					
28	Subtotal Steam	976,055					
29	331.00	172,021	100.00	-25.00	2.38	R2.5	33.00
30	332.10	19,461	95.00	-20.00	1.31	S4.0	39.80
31	332.20	228,289	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	SQUARE	49.10
33	333.00	201,681	80.00	-5.00	1.74	R3.0	32.60
34	334.00	52,292	50.00	-5.00	2.66	R1.5	26.10
35	335.00	20,322	95.00		2.23	R2.0	28.10
36	335.10	76	15.00		7.63	SQUARE	6.50
37	335.20	364	20.00		5.57	SQUARE	5.30
38	335.30	242	5.00		12.36	SQUARE	3.30
39	336.00	8,183	75.00		2.47	R3.0	21.40
40	Subtotal Hydro	708,403					
41	341.00	133,754			2.91	SQUARE	27.20
42	342.00	7,982	50.00		2.97	S2.5	28.50
43	343.00	236,640	40.00		3.33	S1.5	25.90
44	344.00	73,354	45.00		2.51	S2.0	26.80
45	345.00	95,671	50.00		3.26	S1.5	22.60
46	346.00	5,839	35.00		3.33	S2.5	24.50
47	Subtotal Other	553,240					
48	350.20	31,557	70.00		1.39	R3.0	58.80
49	350.22	74			3.33		
50	352.00	70,075	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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	388,935	50.00	-5.00	1.90	R1.5	40.70
13	354.00	162,005	65.00	-15.00	1.70	S3.0	50.80
14	355.00	129,115	60.00	-70.00	2.77	R2.0	43.60
15	356.00	188,089	65.00	-40.00	2.25	R2.0	48.50
16	359.00	390	65.00		0.79	R2.5	24.00
17	Subtotal Transmission	970,240					
18	360.22	35	30.00		3.33		30.00
19	361.00	32,821	65.00	-40.00	2.14	R2.5	53.30
20	362.00	196,766	50.00	-5.00	2.00	R1.0	40.20
21	364.00	235,549	44.00	-45.00	3.08	R1.5	31.30
22	365.00	126,035	45.00	-35.00	2.98	R0.5	33.60
23	366.00	46,290	60.00	-20.00	1.95	R2.0	48.40
24	367.00	207,476	46.00	-15.00	2.26	R2.0	35.30
25	368.00	471,882	35.00	-3.00	2.58	R1.0	27.00
26	369.00	56,858	40.00	-40.00	2.55	R2.0	29.50
27	370.00	14,766	22.00	1.00	3.46	O1.0	17.50
28	370.10	58,377	15.00		6.96	S2.5	13.10
29	371.10	27	12.00	-2.00	2.35	S4.0	9.00
30	371.20	2,875	17.00	-2.00	1.51	R1.5	14.70
31	373.20	4,550	30.00	-25.00	2.41	R1.0	20.60
32	374.00	534					
33	Subtotal Distribution	1,454,841					
34	390.11	28,413	100.00	-5.00	2.58	S0.5	28.80
35	390.12	74,321	55.00	-5.00	1.90	S0.5	44.30
36	390.20	205	35.00		2.15	S3.0	25.70
37	391.11	13,926	20.00		2.88	SQUARE	12.90
38	391.20	19,778	5.00		11.12	SQUARE	3.20
39	391.21	7,194	8.00		11.22	L2.0	5.70
40	392.10	834	12.00	15.00	7.50	L2.0	8.90
41	392.30	3,015	10.00	50.00	1.73	S2.5	3.40
42	392.40	21,079	12.00	15.00	7.36	L2.0	6.80
43	392.50	921	12.00	15.00	3.53	L2.0	9.00
44	392.60	31,210	20.00	15.00	4.14	L2.0	13.40
45	392.70	5,985	20.00	15.00	3.21	L2.0	12.50
46	392.90	4,682	35.00	15.00	2.10	S1.0	24.30
47	393.00	1,909	25.00		3.30	SQUARE	19.40
48	394.00	7,197	20.00		4.13	SQUARE	13.30
49	395.00	12,445	20.00		4.29	SQUARE	12.10
50	396.00	12,801	20.00	30.00	1.66	O1.0	17.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	397.10	5,212	15.00		4.25	SQUARE	8.30
13	397.20	28,811	15.00		5.38	SQUARE	9.80
14	397.30	4,108	15.00		5.31	SQUARE	8.00
15	397.40	5,795	10.00		7.90	SQUARE	6.50
16	398.00	5,737	15.00		5.20	SQUARE	10.60
17	Subtotal General	295,578					
18	Total Plant	4,958,357					
19							
20							
21							
22							
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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	3,325,048		3,325,048	
3					
4	Regulatory FERC fees Tru-up		-89,430	-89,430	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		331,697	331,697	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Intervenor funding		19,685	19,685	
13	Rate Case - Misc expenses		16,732	16,732	
14					
15	Regulatory Commission Expenses - Oregon				
16	Rate Case - Misc expenses		28,246	28,246	
17					
18	Other - OPUC				
19	UM - 1182		27,075	27,075	
20	PURPA		71,901	71,901	
21	General Regulatory		43,721	43,721	
22	Other OPUC expenses		42,488	42,488	
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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44					
45					
46	TOTAL	3,483,549	492,115	3,975,664	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	3,325,048					2
							3
Electric	928	-89,430					4
							5
							6
Electric	928	331,697					7
							8
Electric	928	158,501					9
							10
							11
Electric	928	19,685					12
Electric	928	16,732					13
							14
							15
Electric	928	28,246					16
							17
							18
Electric	928	27,075					19
Electric	928	71,901					20
Electric	928	43,721					21
Electric	928	42,488					22
							23
							24
							25
							26
							27
							28
							29
							30
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							45
		3,975,664					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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 2013.	
3		
4		
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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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	21,853,915		
4	Transmission	6,662,760		
5	Regional Market			
6	Distribution	17,845,496		
7	Customer Accounts	9,457,851		
8	Customer Service and Informational	4,734,128		
9	Sales			
10	Administrative and General	44,979,514		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	105,533,664		
12	Maintenance			
13	Production	5,312,500		
14	Transmission	3,486,701		
15	Regional Market			
16	Distribution	8,303,604		
17	Administrative and General	1,000,149		
18	TOTAL Maintenance (Total of lines 13 thru 17)	18,102,954		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,166,415		
21	Transmission (Enter Total of lines 4 and 14)	10,149,461		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	26,149,100		
24	Customer Accounts (Transcribe from line 7)	9,457,851		
25	Customer Service and Informational (Transcribe from line 8)	4,734,128		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	45,979,663		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	123,636,618		123,636,618
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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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 47)			
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)	123,636,618		123,636,618
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	55,095,638		55,095,638
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	55,095,638		55,095,638
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	4,888,107		4,888,107
79	Other Clearing Accounts	3,283,745		3,283,745
80	Other Work in Progress	1,937,172		1,937,172
81	Paid Absences	22,510,641		22,510,641
82	Preliminary Survey and Investigation	14,149		14,149
83	Other Accounts	5,193,284		5,193,284
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	37,827,098		37,827,098
96	TOTAL SALARIES AND WAGES	216,559,354		216,559,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

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	5,038	16	800	4,068	254	567		149	
2	February	4,601	27	800	3,468	216	567		350	
3	March	4,390	8	800	3,500	187	567		136	
4	Total for Quarter 1	14,029			11,036	657	1,701		635	
5	April	4,280	8	900	3,047	173	567		493	
6	May	5,186	13	1600	3,955	301	567		363	
7	June	5,899	28	1900	4,733	353	567		246	
8	Total for Quarter 2	15,365			11,735	827	1,701		1,102	
9	July	6,132	1	1500	4,990	376	567		199	
10	August	5,561	22	1600	4,374	323	567		297	
11	September	5,221	4	1700	4,381	251	567		22	
12	Total for Quarter 3	16,914			13,745	950	1,701		518	
13	October	4,246	11	900	3,177	180	567		322	
14	November	4,287	14	900	3,244	179	567		297	
15	December	5,032	8	1900	3,808	257	567		400	
16	Total for Quarter 4	13,565			10,229	616	1,701		1,019	
17	Total Year to Date/Year	59,873			46,745	3,050	6,804		3,274	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	6,326,861
4	Nuclear	
5	Hydro-Conventional	5,656,364
6	Hydro-Pumped Storage	
7	Other	1,576,501
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	13,559,726
10	Purchases	3,881,443
11	Power Exchanges:	
12	Received	310,770
13	Delivered	289,119
14	Net Exchanges (Line 12 minus line 13)	21,651
15	Transmission For Other (Wheeling)	
16	Received	6,358,859
17	Delivered	6,361,562
18	Net Transmission for Other (Line 16 minus line 17)	-2,703
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,460,117

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,619,354
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,683,294
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,157,469
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,460,117

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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,521,727	87,925	2,442	22	8 AM
30	February	1,303,296	202,177	2,048	11	8 AM
31	March	1,289,076	211,377	1,909	4	8 AM
32	April	1,146,697	65,379	1,854	29	11 AM
33	May	1,406,880	73,183	2,575	13	7 PM
34	June	1,619,468	61,453	3,201	29	5 PM
35	July	1,853,099	55,351	3,407	2	4 PM
36	August	1,707,637	50,565	2,916	14	6 PM
37	September	1,395,010	200,171	2,567	4	5 PM
38	October	1,264,202	194,114	1,740	30	9 AM
39	November	1,370,199	267,036	1,986	22	8 AM
40	December	1,582,827	214,563	2,482	9	8 AM
41	TOTAL	17,460,118	1,683,294			

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

Page 329 Column I differs from Page 401 by 2,703 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. However 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) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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)	733			61		
7	Plant Hours Connected to Load	8760			7254		
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	4880898000			328026000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	67574164			14291124		
15	Equipment Costs	475553447			60881102		
16	Asset Retirement Costs	2375172			4075579		
17	Total Cost	545997141			79354415		
18	Cost per KW of Installed Capacity (line 17/5) Including	708.6270			1236.0501		
19	Production Expenses: Oper, Supv, & Engr	212113			502428		
20	Fuel	111039712			6433944		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5614513			637875		
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	7137763			580476		
27	Rents	348322			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	43530			58089		
30	Maintenance of Structures	0			42751		
31	Maintenance of Boiler (or reactor) Plant	7763074			237986		
32	Maintenance of Electric Plant	2808725			2009281		
33	Maintenance of Misc Steam (or Nuclear) Plant	4400890			16636		
34	Total Production Expenses	139368642			10519466		
35	Expenses per Net KWh	0.0286			0.0321		
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	2661214	7344	0	189136	930	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9340	140000	0	8352	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.282	153.487	0.000	32.427	128.563	0.000
41	Average Cost of Fuel per Unit Burned	41.354	94.618	0.000	33.220	133.772	0.000
42	Average Cost of Fuel Burned per Million BTU	2.196	16.091	0.000	1.959	22.943	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.023	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	10277.000	0.000	0.000	9792.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	307	0
7	Plant Hours Connected to Load	5250	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	19	0
12	Net Generation, Exclusive of Plant Use - KWh	1295859000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	126178288	0
15	Equipment Costs	248481897	0
16	Asset Retirement Costs	0	0
17	Total Cost	376947446	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1183.6943	0
19	Production Expenses: Oper, Supv, & Engr	896202	0
20	Fuel	40866185	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	2741126	0
26	Misc Steam (or Nuclear) Power Expenses	139367	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	42	0
30	Maintenance of Structures	72559	0
31	Maintenance of Boiler (or reactor) Plant	78592	0
32	Maintenance of Electric Plant	528420	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	45322493	0
35	Expenses per Net KWh	0.0350	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	8967970	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	4.557	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.557	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.390	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.320	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7107.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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
261			300			196			6
7532			1231			540			7
0			261			164			8
0			0			0			9
0			0			0			10
0			8			5			11
1117937000			200414000			80190000			12
1106140			402745			0			13
65742458			5887090			1676601			14
281331744			109272050			60834553			15
3595055			0			0			16
351775397			115561885			62511154			17
1240.8303			426.5850			361.7544			18
810416			245070			92035			19
42803085			9568193			3757903			20
0			0			0			21
2588497			0			0			22
0			0			0			23
0			0			0			24
1741112			377365			307498			25
1755527			193702			130520			26
0			0			0			27
0			0			27			28
0			31			99968			29
595094			128760			4772			30
4460826			2154			335369			31
580977			370194			0			32
123918			0			0			33
55459452			10885469			4728092			34
0.0496			0.0543			0.0590			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
642255	13332	0	2029638	0	0	830725	0	0	38
8695	138778	0	1027	0	0	1027	0	0	39
39.321	146.416	0.000	4.714	0.000	0.000	4.524	0.000	0.000	40
63.525	146.206	0.000	4.714	0.000	0.000	4.524	0.000	0.000	41
3.653	25.084	0.000	4.490	0.000	0.000	4.270	0.000	0.000	42
0.038	0.000	0.000	0.048	0.000	0.000	0.470	0.000	0.000	43
10060.000	0.000	0.000	10401.000	0.000	0.000	10639.000	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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	94	52
7	Plant Hours Connect to Load	4,891	8,756
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	243,830,000	291,809,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,772,499	1,083,396
16	Reservoirs, Dams, and Waterways	4,293,075	8,413,888
17	Equipment Costs	31,985,167	8,848,494
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,765,335	19,600,621
21	Cost per KW of Installed Capacity (line 20 / 5)	539.1694	261.3416
22	Production Expenses		
23	Operation Supervision and Engineering	313,116	898,744
24	Water for Power	1,260,918	503,953
25	Hydraulic Expenses	140,851	625,194
26	Electric Expenses	50,110	55,216
27	Misc Hydraulic Power Generation Expenses	225,065	312,980
28	Rents	84	9,282
29	Maintenance Supervision and Engineering	6,192	3,817
30	Maintenance of Structures	175,001	35,354
31	Maintenance of Reservoirs, Dams, and Waterways	5,683	51,201
32	Maintenance of Electric Plant	280,176	178,533
33	Maintenance of Misc Hydraulic Plant	202,419	143,754
34	Total Production Expenses (total 23 thru 33)	2,659,615	2,818,028
35	Expenses per net KWh	0.0109	0.0097

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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)	354	23
7	Plant Hours Connect to Load	8,760	8,677
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	2
12	Net Generation, Exclusive of Plant Use - Kwh	1,422,250,000	144,563,000
13	Cost of Plant		
14	Land and Land Rights	1,880,407	205,375
15	Structures and Improvements	2,728,449	2,778,755
16	Reservoirs, Dams, and Waterways	52,738,008	6,262,987
17	Equipment Costs	19,731,257	4,454,070
18	Roads, Railroads, and Bridges	922,781	309,805
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,000,902	14,010,992
21	Cost per KW of Installed Capacity (line 20 / 5)	199.2360	643.5917
22	Production Expenses		
23	Operation Supervision and Engineering	322,558	125,188
24	Water for Power	157,679	671,591
25	Hydraulic Expenses	750,899	84,329
26	Electric Expenses	208,651	30,460
27	Misc Hydraulic Power Generation Expenses	565,077	93,997
28	Rents	13,965	0
29	Maintenance Supervision and Engineering	13,387	3,051
30	Maintenance of Structures	97,820	12,707
31	Maintenance of Reservoirs, Dams, and Waterways	378,090	11,088
32	Maintenance of Electric Plant	226,451	91,163
33	Maintenance of Misc Hydraulic Plant	456,128	211,875
34	Total Production Expenses (total 23 thru 33)	3,190,705	1,335,449
35	Expenses per net KWh	0.0022	0.0092

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	14
7	Plant Hours Connect to Load	8,760	6,061
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	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	188,593,000	64,995,000
13	Cost of Plant		
14	Land and Land Rights	202,398	313,328
15	Structures and Improvements	2,037,511	1,257,955
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	8,793,806	4,678,182
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	16,632,245	6,813,250
21	Cost per KW of Installed Capacity (line 20 / 5)	482.0941	545.0600
22	Production Expenses		
23	Operation Supervision and Engineering	370,652	325,551
24	Water for Power	154,204	121,314
25	Hydraulic Expenses	392,549	260,491
26	Electric Expenses	107,672	33,536
27	Misc Hydraulic Power Generation Expenses	192,849	196,103
28	Rents	0	70
29	Maintenance Supervision and Engineering	5,747	3,211
30	Maintenance of Structures	167,404	38,102
31	Maintenance of Reservoirs, Dams, and Waterways	195,445	46,966
32	Maintenance of Electric Plant	111,100	167,209
33	Maintenance of Misc Hydraulic Plant	141,695	91,727
34	Total Production Expenses (total 23 thru 33)	1,839,317	1,284,280
35	Expenses per net KWh	0.0098	0.0198

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
552	14	207	6
8,760	8,745	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	7	11
1,678,769,000	39,982,000	744,020,000	12
			13
18,092,312	82,142	1,213,449	14
32,068,242	7,364,154	10,586,706	15
67,073,285	3,145,630	30,435,630	16
57,971,691	12,693,212	18,350,111	17
518,444	122,668	565,842	18
0	0	0	19
175,723,974	23,407,806	61,151,738	20
300.1776	1,884.6865	321.8513	21
			22
529,568	221,701	274,726	23
260,735	162,004	131,435	24
1,223,022	606,699	627,318	25
290,462	164,936	145,733	26
966,773	405,973	519,124	27
51,204	65	8,395	28
17,852	2,916	9,023	29
142,426	33,128	320,809	30
223,950	2,102	3,821	31
455,526	124,450	138,360	32
634,482	95,768	244,201	33
4,796,000	1,819,742	2,422,945	34
0.0029	0.0455	0.0033	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
84	19	36	6
8,759	8,751	5,827	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
358,642,000	108,062,000	55,373,000	12
			13
5,476,746	102,678	255,499	14
9,545,892	25,479,513	10,962,300	15
10,708,043	13,856,887	7,975,451	16
12,998,664	30,566,685	20,892,570	17
210,416	835,946	1,917,603	18
0	0	0	19
38,939,761	70,841,709	42,003,423	20
470.2870	2,833.6684	796.4244	21
			22
996,276	631,494	248,035	23
407,453	225,115	86,481	24
1,162,353	579,834	135,224	25
48,586	16,332	63,507	26
479,084	286,528	133,279	27
44,397	6,784	2,628	28
4,112	5,251	2,468	29
65,105	107,319	38,703	30
81,776	72,969	8,289	31
202,910	275,825	67,924	32
90,710	106,391	149,401	33
3,582,762	2,313,842	935,939	34
0.0100	0.0214	0.0169	35

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	40	37	6
0	8,760	4,834	7
			8
0	64	61	9
0	60	1	10
0	3	2	11
0	194,164,000	52,819,000	12
			13
114,367	424,428	138,100	14
40,625,699	2,822,579	10,353,694	15
13,556,785	6,920,148	17,114,934	16
1,904,696	8,052,877	28,539,419	17
99,051	88,693	501,877	18
0	0	0	19
56,300,598	18,308,725	56,648,024	20
0.0000	305.1454	952.8684	21
			22
0	444,132	266,922	23
0	131,997	1,378,381	24
6,551,530	212,537	122,619	25
0	65,965	52,409	26
0	220,375	211,130	27
0	2,148	2,573	28
0	4,087	2,035	29
0	84,384	48,507	30
0	53,579	10,607	31
0	137,535	103,043	32
157,357	162,320	55,851	33
6,708,887	1,519,059	2,254,077	34
0.0000	0.0078	0.0427	35

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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	12,313	1,784,119
3	Thousand Springs	1912	8.80	7.6	56,180	9,391,284
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	4.0	38	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
12						
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Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
713,648	142,631		73,144			2
1,067,191	193,242		109,390			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Borah	Midpoint	345.00	500.00	S Tower	85.17		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.40		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		1
5								
6	Jim Bridger	Goshen	345.00	345.00	S Tower	226.16		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.06		2
8	Kinport	Borah	345.00	345.00	S Tower	27.10		1
9	Midpoint	Borah #1	345.00	345.00	H Wood	79.30		1
10	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
11	Adelaide Tap	Adelaide	345.00	345.00	H Wood	3.55		2
12								
13	Quartz	LaGrande	230.00	230.00	H Wood	46.27		1
14	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
15	Brady	Antelope	230.00	230.00	H Wood	56.41		1
16	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
17	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
18	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
19	Brownlee	Ontario	230.00	230.00	S Tower	72.74		1
20	Mora	Bowmont	138.00	230.00	S P Wood	9.91		1
21	Mora	Bowmont	138.00	230.00	H Wood	8.82		1
22	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
23	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
24	Boise Bench	Caldwell	230.00	230.00	S Tower	7.58		1
25	Boise Bench	Caldwell	230.00	230.00	H Wood	33.68		1
26	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.94		2
27	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
28	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
29	Caldwell	Ontario	230.00	230.00	H Wood	29.97		1
30	Caldwell	Ontario	230.00	230.00	S Tower	3.27		1
31	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
32	Borah	Hunt	230.00	230.00	H Steel	68.22		1
33	Danskin	Hubbard	230.00	230.00	H Steel	36.25		1
34	Danskin	Hubbard	230.00	230.00	SP Steel	1.90		1
35	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
36					TOTAL	4,779.36	11.02	190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.39		1
2	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
3	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
4	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
5	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
6	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.49		1
7	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
8	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
9	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
10	Oxbow	Brownlee	230.00	230.00	S Tower	10.40		2
11	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
12	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
13	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.08		2
14	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
15	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.04		2
16	Brownlee	Boise Bench	230.00	230.00	S Tower	102.54		2
17	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.30		1
18	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
19	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
20	Borah	Brady #2	230.00	230.00	H Wood	3.56		1
21	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
22								
23	Goshen	State Line	161.00	161.00	H Wood	90.60		1
24	Don	Goshen	161.00	161.00	S Tower	2.37		2
25	Don	Goshen	161.00	161.00	H Wood	48.42		2
26								
27	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.22		2
28	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
29	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.13		2
30	Nampa	Caldwell	138.00	138.00	S P Wood	9.58		2
31	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.42		1
32	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
33	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
34	Brady	Fremont	138.00	138.00	S Tower	1.00		2
35	Brady	Fremont	138.00	138.00	H Wood	24.32		2
36					TOTAL	4,779.36	11.02	190

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION LINE STATISTICS

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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	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
2	King	Lower Malad	138.00	138.00	H Wood	84.77		2
3	Emmett Jct	Payette	138.00	138.00	H Wood	66.49		2
4	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
5	Ontario	Quartz	138.00	138.00	H Wood	73.40		1
6	King	American Falls PP	138.00	138.00	S Tower	1.01		2
7	King	American Falls PP	138.00	138.00	H Wood	142.41		1
8	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
9	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
10	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
11	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
12	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
13	King	Wood River	138.00	138.00	H Wood	73.79		1
14	Boise Bench	Grove	138.00	138.00	S P Wood	10.58		2
15	Quartz	John Day	138.00	138.00	H Wood	67.32		1
16	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
17	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
18	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
19	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
20	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
21	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
22	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
23	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
24	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
25	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
26	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.51		2
27	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
28	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.50		1
29	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
30	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
31	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.22		2
32	Twin Falls	Russett	138.00	138.00	S P Wood	1.70		1
33	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
34	Peterson	Tendoy	69.00	138.00	H Wood	57.23		1
35	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
36					TOTAL	4,779.36	11.02	190

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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	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.83		2
2	Boise Bench	Mora	138.00	138.00	H Wood	13.14		2
3	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
4	Gary Lane	Eagle	138.00	138.00	S P Wood	6.54		1
5	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
6	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
7	Eagle	Star	138.00	138.00	S P Wood	6.37		1
8	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.60		1
9	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
10	Victory Jct	Victory	138.00	138.00	S P Steel	1.90		1
11	Butler	Wye	138.00	138.00	S P Steel	2.94		1
12	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
13	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
14	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
15	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
16	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
17	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.79		1
18	Garnet	Ward		138.00				
19	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
20	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
21	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
22	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
23	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
24	Valivue Tap		138.00	138.00	S P Steel	0.80		2
25	Bowmont	Happy Valley	138.00	138.00	S P Steel			1
26	Kinport	Don #1	138.00	138.00	S Tower	1.32		2
27	Donn	HOKU	138.00	138.00	S P Steel	2.74		1
28	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
29	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
30	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
31	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.29		1
32	King	Justice	138.00	138.00	S P Wood	0.11		1
33	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
34	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
35	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
36					TOTAL	4,779.36	11.02	190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/15/2014	End of 2013/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	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
2	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.44		1
3	Strike Jct	Bowmont		138.00	H Wood	0.05		1
4	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
5	Strike Jct	Bowmont	138.00	138.00	H Wood	68.21		1
6	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
7	Bliss	King	138.00	138.00	H Wood	10.47		1
8	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
9	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
10								
11								
12								
13	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
14								
15								
16	69 Kv Lines		69.00	69.00	H Wood	167.03		1
17	69 Kv Lines		69.00	69.00	S P Wood	938.22		1
18								
19								
20	46 Kv Lines		46.00	46.00	S P Wood	408.82		1
21								
22	Total all lines					4,779.36	11.02	190
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,779.36	11.02	190

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	21,838,866	22,095,247					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		835,662	835,662					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,830,982	17,314,291					6
795 ACSR	571,979	11,048,287	11,620,266					7
1272 ACSR	344,220	6,008,061	6,352,281					8
715.5 ACSR	283,143	9,470,503	9,753,646					9
715.5 ACSR	64,851	15,994,935	16,059,786					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	5,440,572	5,502,790					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	3,415,600	3,523,901					15
795 ACSR		6,186	6,186					16
715.5 ACSR	18,829	969,871	988,700					17
1272 ACSR	1,190	51,525	52,715					18
2X954 ACSR	1,676,838	20,541,790	22,218,628					19
715.5 ACSR	413,793	2,197,386	2,611,179					20
715.5 ACSR								21
1272 ACSR	1,899	212,523	214,422					22
1590 ACSR	2,138,236	8,775,086	10,913,322					23
1272 ACSR	213,000	8,575,360	8,788,360					24
715.5 ACSR								25
1272 ACSR	3,062,812	6,567,671	9,630,483					26
795 AAC		89,756	89,756					27
954 ACSR	34,174	16,026,470	16,060,644					28
2X954 ACSR	236,152	9,228,893	9,465,045					29
1272 ACSR								30
1272 ACSR	81,701	1,666,354	1,748,055					31
1590 ACSR	624,917	22,468,666	23,093,583					32
1590 ACSR		15,210,561	15,210,561					33
1590 ACSR								34
1590 ACSR								35
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	36

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
1590 ACSR		3,528,033	3,528,033					1
1590 ACSR	1,854,996	9,284,271	11,139,267					2
1590 ACSR	948,166	9,080,890	10,029,056					3
1272 ACSR								4
715.5 ACSR	385,287	6,638,374	7,023,661					5
715.5 ACSR								6
795 ACSR	53,068	2,833,575	2,886,643					7
795 ACSR								8
VARIOUS	289,934	9,010,839	9,300,773					9
1272 ACSR	14,810	1,237,524	1,252,334					10
715.5 ACSR	227,825	14,413,191	14,641,016					11
VARIOUS								12
1272 ACSR	87,468	2,168,767	2,256,235					13
1272 ACSR	171,081	1,540,815	1,711,896					14
1272 ACSR	44,687	1,252,130	1,296,817					15
954 ACSR	184,817	6,257,154	6,441,971					16
715.5 ACSR	247,857	5,655,753	5,903,610					17
1272 ACSR	84,014	1,881,216	1,965,230					18
1272 ACSR	3,068	416,606	419,674					19
715.5 ACSR								20
1272 ACSR	10,064	311,349	321,413					21
								22
250 COPPER	16,155	648,382	664,537					23
715.5 ACSR	76,041	1,735,843	1,811,884					24
397.5 ACSR								25
								26
250 COPPER	26,507	339,394	365,901					27
250 COPPER								28
715.5 ACSR	21,327	249,232	270,559					29
795 AAC	654,753	3,234,060	3,888,813					30
795 ACSR	47,687	3,539,654	3,587,341					31
795 ACSR	43,568	1,085,989	1,129,557					32
795 AAC	270,823	557,504	828,327					33
VARIOUS	564,932	3,795,845	4,360,777					34
VARIOUS								35
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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.
VARIOUS								1
VARIOUS	76,823	2,300,949	2,377,772					2
VARIOUS	33,918	2,736,643	2,770,561					3
397.5 ACSR	1,955	6,930	8,885					4
VARIOUS	34,428	5,088,718	5,123,146					5
715.5 ACSR	216,919	8,549,033	8,765,952					6
715.5 ACSR								7
715.5 ACSR								8
4\0	4,191	309,857	314,048					9
954 ACSR		96,921	96,921					10
250 COPPER	2,741	121,992	124,733					11
VARIOUS	28,490	3,062,131	3,090,621					12
VARIOUS	173,683	3,826,177	3,999,860					13
VARIOUS	225,602	1,652,772	1,878,374					14
397.5 ACSR	92,173	2,362,416	2,454,589					15
VARIOUS	20	77,199	77,219					16
715.5 ACSR	3,123,380	8,203,108	11,326,488					17
VARIOUS								18
795AAC								19
1272 ACSR								20
250 COPPER	450	187,848	188,298					21
397.5 ACSR	349,712	7,017,826	7,367,538					22
397.5 ACSR								23
397.5 ACSR	109,899	2,469,079	2,578,978					24
397.5 ACSR								25
715.5 ACSR	211,131	1,448,294	1,659,425					26
715.5 ACSR	3,324	1,416,503	1,419,827					27
397.5 ACSR	14,927	620,412	635,339					28
715.5 ACSR	13,734	1,051,324	1,065,058					29
397.5 ACSR	18,223	1,284,245	1,302,468					30
VARIOUS	54,848	3,086,512	3,141,360					31
715.5 ACSR	16,790	206,158	222,948					32
715.5 ACSR	13,616	530,274	543,890					33
397.5 ACSR	395,696	3,449,973	3,845,669					34
715.5 ACSR	343,955	2,134,314	2,478,269					35
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	36

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR								1
715.5 ACSR	14,697	637,273	651,970					2
795 AAC		49,642	49,642					3
795 AAC	489,037	2,177,348	2,666,385					4
1272 ACSR	935,725	3,601,834	4,537,559					5
1272 ACSR	34,687	838,605	873,292					6
715.5 ACSR	179,817	3,047,204	3,227,021					7
795 AAC	43,035	434,341	477,376					8
1272 ACSR	140,412	2,577,075	2,717,487					9
1272 ACSR								10
795 ACSR	134,471	1,405,436	1,539,907					11
715.5 ACSR	2,473,833	18,402,119	20,875,952					12
715.5 ACSR								13
715.5 ACSR								14
715.5 ACSR								15
715.5 ACSR								16
1272 ACSR	78,579	1,821,921	1,900,500					17
	40,580		40,580					18
715.5 ACSR	331,539	4,682,879	5,014,418					19
								20
1272 ACSR	272,231	2,141,218	2,413,449					21
795 ACSR								22
795 ACSR								23
795 ACSR		427,769	427,769					24
1272 ACSR	671,138		671,138					25
715.5 ACSR	1,174	212,777	213,951					26
1272 ACSR	190	398	588					27
1272 ACSR								28
795 ACSR								29
795 ACSR								30
795 ACSR		-16,973	-16,973					31
1590 ACSR		60,659	60,659					32
250 COPPER	58	63,264	63,322					33
715.5 ACSR		76,560	76,560					34
397.5 ACSR		4,406	4,406					35
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	36

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)
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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)	
715.5 ACSR	1,074	624,098	625,172					1
397.5 ACSR	4,355	2,296,216	2,300,571					2
715.5 ACSR	86,651	2,027,148	2,113,799					3
715.5 ACSR								4
								5
715.5 ACSR	7	279,481	279,488					6
715.5 ACSR	5,620	997,718	1,003,338					7
715.5 ACSR	2,814	183,606	186,420					8
397.5 ACSR	12,885	261,511	274,396					9
								10
								11
								12
397.5 ACSR	1,978	63,404	65,382					13
								14
								15
VARIOUS	1,644,178	56,843,386	58,487,564					16
VARIOUS								17
								18
								19
VARIOUS	194,536	15,653,177	15,847,713					20
				7,215,461	3,912,451	2,917,528	14,045,440	21
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	30,423,400	481,134,170	511,557,570	7,215,461	3,912,451	2,917,528	14,045,440	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	No lines were added in 2013						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
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38							
39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
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Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
10	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	13.00	
14	Blackfoot	transmission	161.00	46.00	12.47
15	Blackfoot	distribution	161.00	138.00	12.98
16	Bliss - attended	transmission	138.00	13.80	
17	Blue Gulch	distribution	138.00	35.00	
18	Boise Bench - attended	transmission	230.00	138.00	13.20
19	Boise Bench - attended	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	138.00	69.00	12.98
21	Boise Bench - attended	transmission	230.00	138.00	13.80
22	Boise	distribution	138.00	13.00	
23	Borah	transmission	345.00	230.00	13.80
24	Bowmont	distribution	69.00	46.00	6.90
25	Bowmont	distribution	138.00	35.00	
26	Bowmont	transmission	138.00	69.00	12.98
27	Bowmont	transmission	138.00	69.00	12.47
28	Bowmont	transmission	230.00	138.00	13.80
29	Brady	distribution	46.00	13.00	
30	Brady	transmission	230.00	138.00	13.80
31	Brady	transmission	138.00	46.00	12.47
32	Brady	distribution	69.00	13.00	
33	Brownlee - attended	transmission	230.00	13.80	
34	Bruneau Bridge	distribution	138.00	35.00	
35	Buckhorn	distribution	69.00	35.00	
36	Bucyrus	distribution	46.00	7.20	
37	Buhl	distribution	46.00	13.00	
38	Burley Rural	distribution	69.00	13.00	
39	Butler	distribution	138.00	13.09	
40	Caldwell	distribution	138.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Caldwell	transmission	230.00	138.00	
2	Caldwell	distribution	138.00	13.09	
3	Caldwell	transmission	138.00	69.00	12.47
4	Caldwell	transmission	230.00	138.00	12.47
5	Caldwell	distribution	13.00	4.16	
6	Canyon Creek	distribution	138.00	35.00	
7	Canyon Creek	transmission	138.00	69.00	12.98
8	Cascade Power Plant - attended	transmission	69.00	4.60	
9	Cascade	distribution	69.00	13.10	
10	Cascade	distribution	25.00		
11	Chestnut	distribution	138.00	13.00	
12	Clear Lake - attended	transmission	46.00	2.40	
13	Cliff	transmission	138.00	46.00	12.50
14	Cliff	transmission	138.00	46.00	12.95
15	Cloverdale	distribution	138.00	13.00	
16	Dale	distribution	46.00	4.60	
17	Dale	distribution	46.00	13.00	
18	Dale	distribution	69.00	13.00	
19	Dale	distribution	138.00	36.20	
20	Dale	transmission	138.00	46.00	12.47
21	Danskin- attended	transmission	230.00	18.00	
22	Danskin- attended	transmission	230.00	138.00	13.80
23	Danskin- attended	distribution	18.00	4.16	
24	Danskin- attended	transmission	138.00	12.00	
25	Danskin- attended	distribution	35.00	13.80	
26	Don	distribution	138.00	7.60	
27	Don	distribution	138.00	13.20	
28	Don	distribution	138.00	13.00	
29	Don	distribution	14.00		
30	DRAM	distribution	138.00	13.09	
31	DRAM	transmission	230.00	138.00	13.80
32	DRAM	distribution	138.00	12.47	
33	Duffin	distribution	138.00	35.00	
34	Eagle	distribution	138.00	13.09	
35	Eastgate	distribution	138.00		
36	Eastgate	distribution	138.00	13.00	
37	Eckert	distribution	138.00	36.20	
38	Eden	distribution	138.00	36.20	
39	Eden	transmission	138.00	46.00	12.98
40	Elkhorn	distribution	138.00	12.47	

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.
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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	Elkhorn	distribution	138.00	13.00	
2	Elmore	distribution	138.00	35.00	
3	Elmore	transmission	138.00	69.00	12.50
4	Elmore	transmission	138.00	69.00	12.98
5	Emmett	distribution	138.00		
6	Emmett	transmission	138.00	69.00	12.47
7	Falls	distribution	46.00	13.00	
8	Filer	distribution	46.00	13.00	
9	Flat Top	distribution	46.00	13.00	13.00
10	Flying H	distribution	69.00	2.40	
11	Fort Hall	distribution	46.00	13.00	
12	Fossil Gulch	distribution	138.00	35.00	
13	Fremont	transmission	138.00	46.00	12.50
14	Gary	distribution	138.00	13.09	
15	Gary	distribution	138.00	13.00	
16	Gem	distribution	69.00	13.00	
17	Gem	distribution	69.00		
18	Goodng Rural	distribution	46.00	13.00	
19	Golden Valley	distribution	69.00	13.00	
20	Gowen Substation	distribution	138.00	35.00	
21	Grindstone	distribution	35.00		
22	Grove	distribution	138.00	13.09	
23	Grove	distribution	138.00	13.00	
24	Hagerman	distribution	46.00	13.00	
25	Hagerman	distribution	46.00	13.00	32.00
26	Hailey	distribution	138.00	13.00	
27	Happy Valley	distribution	138.00	13.09	
28	Haven	distribution	138.00	35.00	
29	Haven	transmission	138.00	46.00	
30	Hemingway	transmission	500.00	230.00	34.50
31	Hewlett Packard	distribution	138.00	13.00	
32	Hidden Springs	distribution	138.00	13.00	
33	Highland	distribution	138.00	13.00	
34	Hill	distribution	138.00	13.00	
35	Hillsdale	distribution	138.00		
36	Hoku	distribution	138.00	13.80	
37	Homedale	distribution	69.00	13.00	
38	Horse Flat	transmission	230.00	138.00	13.80
39	Horseshoe Bend	distribution	35.00		
40	Horseshoe Bend	distribution	69.00	36.20	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Horseshoe Bend	distribution	69.00	25.00	
2	Huston	distribution	69.00	13.00	
3	Hulen	distribution	46.00	13.00	
4	Hunt	transmission	230.00	138.00	13.80
5	Hydra	distribution	138.00	36.20	
6	Island	distribution	69.00	13.00	
7	Jerome	distribution	138.00	13.00	
8	Jerome	distribution	138.00	13.09	
9	Julion Clawson	distribution	138.00	35.00	
10	Joplin	distribution	138.00	13.00	
11	Joplin	distribution	138.00	35.00	
12	Justice	transmission	230.00	138.00	13.80
13	Karcher	distribution	138.00	13.00	
14	Kenyon	distribution	69.00	13.00	
15	Ketchum	distribution	138.00	13.00	
16	Kimberly	distribution	138.00	13.00	
17	Kinport	transmission	161.00	46.00	13.20
18	Kinport	transmission	230.00	138.00	12.47
19	Kinport	transmission	230.00	138.00	13.80
20	Kinport	transmission	345.00	230.00	13.80
21	Kramer	distribution	138.00	35.00	
22	Kramer	distribution	138.00	36.20	
23	Kuna	distribution	138.00	13.00	
24	Lake	distribution	69.00	13.00	
25	Lake Fork	distribution	138.00	36.20	
26	Lake Fork	transmission	138.00	69.00	12.50
27	Lamb	distribution	138.00	13.00	
28	Langley Gulch- attended	transmission	230.00	138.00	13.80
29	Langley Gulch- attended	transmission	230.00		
30	Langley Gulch- attended	distribution		4.16	
31	Langley Gulch- attended	distribution	13.00	4.16	
32	Lansing	distribution	69.00	13.00	
33	Lincoln	distribution	138.00	13.09	
34	Linden	distribution	138.00	13.00	
35	Locust	distribution	138.00	36.20	
36	Locust	transmission	230.00	138.00	13.80
37	Lower Malad - attended	transmission	138.00	7.20	
38	Lower Salmon - attended	transmission	138.00	13.80	
39	Map Rock	distribution	69.00	13.00	
40	McCall	distribution	13.00	13.09	

SUBSTATIONS

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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	McCall	distribution	138.00	36.20	
2	Meridian	distribution	138.00	13.00	
3	Micron	distribution	138.00	13.09	
4	Micron	distribution	138.00	13.00	
5	Midpoint	transmission	230.00	138.00	13.80
6	Midpoint	transmission	345.00	230.00	13.80
7	Midpoint	transmission	500.00	345.00	
8	Midrose	distribution	138.00	13.09	
9	Milner	transmission	138.00	69.00	12.47
10	Milner	distribution	69.00	46.00	6.90
11	Milner	distribution	138.00	35.00	
12	Milner PP - attended	transmission	138.00	13.80	
13	Moonstone	distribution	138.00	35.00	
14	Mora	distribution	138.00	35.00	
15	Mora	distribution	138.00	36.20	
16	Moreland	distribution	35.00	13.00	
17	Moreland	distribution	46.00	13.00	
18	Moreland	distribution	46.00	35.00	12.47
19	Mountain Home	distribution	69.00	13.00	
20	Mountain Home Air Force Base	distribution	69.00	13.00	
21	Mountain Home Air Force Base	distribution	138.00	13.00	
22	Nampa	transmission	230.00	138.00	13.80
23	Nampa	distribution	138.00	13.00	
24	New Meadows	distribution	138.00	36.20	
25	New Plymouth	distribution	69.00	13.00	
26	Notch Butte	distribution	138.00	13.09	
27	Orchard	distribution	69.00	36.20	
28	Orchard	distribution	69.00	35.00	12.47
29	Parma	distribution	69.00	13.00	
30	Parma	distribution	69.00	35.00	
31	Paul	distribution	138.00	35.00	
32	Payette	distribution	138.00	13.00	
33	Pingree	transmission	138.00	46.00	12.50
34	Pingree	distribution	138.00	35.00	
35	Pleasant Valley	distribution	138.00	35.00	
36	Pocatello	distribution	46.00	13.00	
37	Poleline	distribution	138.00	13.09	
38	Populus	transmission	345.00		
39	Portneuf	distribution	138.00	35.00	
40	Portneuf	distribution	46.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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	Rockford	distribution	46.00	13.00	
2	Russett	distribution	138.00	13.00	
3	Sailor Creek	distribution	138.00	2.40	
4	Sailor Creek	distribution	138.00	35.00	
5	Salmon	distribution	69.00	13.00	
6	Salmon	distribution	69.00	34.50	12.47
7	Salmon	distribution	69.00		12.47
8	Salmon	transmission	13.00	2.40	
9	Shoshone	distribution	46.00	13.00	
10	Shoshone	distribution	46.00	7.20	
11	Shoshone Falls - attended	transmission	46.00	2.30	
12	Shoshone Falls - attended	transmission	46.00	6.60	
13	Silver	distribution	138.00	35.00	
14	Simplot	distribution	138.00	13.00	
15	Sinker Creek	distribution	138.00	35.00	
16	Siphon	distribution	138.00	35.00	
17	South Park	distribution	46.00	13.00	
18	Star	distribution	138.00	13.09	
19	Starkey	transmission	138.00	69.00	12.47
20	State	distribution	69.00	13.00	
21	Stoddard	distribution	138.00	13.00	
22	Strike Power Plant - attended	transmission	138.00	13.80	
23	Sugar	distribution	138.00	35.00	
24	Swan Falls - attended	transmission	138.00	6.90	
25	Taber	distribution	46.00	13.00	
26	Ten Mile	distribution	138.00	13.09	
27	Terry	distribution	138.00	13.09	
28	Terry	distribution	138.00	13.00	
29	Thousand Springs - attended	transmission	46.00	7.20	
30	Thousand Springs - attended	transmission	7.00	2.40	
31	Toponis	distribution	138.00	33.00	
32	Twin Falls	distribution	138.00	13.09	
33	Twin Falls	transmission	138.00	46.00	12.98
34	Twin Falls PP - attended	transmission	138.00	7.20	
35	Twin Falls PP - attended	transmission	138.00	13.20	
36	Upper Malad - attended	transmission	45.00	7.20	
37	Upper Salmon- attended	transmission	138.00	7.20	
38	Ustick	distribution	138.00	13.00	
39	Vallivue	distribution	138.00	13.09	
40	Victory	distribution	138.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Victory	distribution	138.00	13.09	
2	Ware	distribution	69.00	13.00	
3	Weiser	distribution	69.00	13.00	
4	Weiser	transmission	138.00	69.00	12.47
5	Wilder	distribution	69.00	13.00	
6	Willis	distribution	138.00	13.09	
7	Wye	distribution	138.00	13.00	
8	Wye	distribution	138.00	13.09	
9	Zilog	distribution	138.00	13.09	
10					
11					
12	The above are all State of Idaho				
13					
14	Montana:				
15	Peterson	transmission	230.00	69.00	13.20
16					
17	Nevada:				
18	Valmy - attended	transmission	345.00	125.00	24.90
19	Valmy - attended	transmission	345.00	125.00	24.90
20	Valmy - attended	transmission	120.00	24.90	7.20
21	Valmy - attended	transmission	345.00		
22	Valmy - attended	transmission	345.00		
23	Valmy - attended	transmission	345.00		
24	Valmy - attended	transmission	345.00		
25	Valmy - attended	transmission	345.00		
26	Wells	transmission	138.00	69.00	13.00
27					
28	Oregon:				
29	Boardman - attended	transmission	500.00	24.00	
30	Boardman - attended	transmission	230.00	7.20	
31	Boardman - attended	transmission	24.00	7.20	
32	Cairo	distribution	69.00	13.00	
33	Hells Canyon - attended	transmission	230.00	13.80	
34	Hells Canyon - attended	distribution	69.00	0.50	
35	Hines	transmission	138.00	115.00	12.47
36	Malheur Butte	distribution	69.00	34.50	
37	Nyssa	distribution	69.00	13.00	
38	Ontario	distribution	138.00	13.00	
39	Ontario	transmission	138.00	69.00	12.47
40	Ontario	transmission	230.00	138.00	13.80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	 Secondary (d)	 Tertiary (e)
1	Ontario	transmission	138.00	69.00	12.98
2	Ontario	transmission	138.00	69.00	13.09
3	Ore-Ida	distribution	69.00	13.00	
4	Oxbow - attended	transmission	138.00	69.00	13.00
5	Oxbow - attended	transmission	230.00	13.80	
6	Oxbow - attended	transmission	230.00	138.00	13.80
7	Quartz	transmission	138.00	69.00	12.50
8	Quartz	transmission	230.00	138.00	12.98
9	Quartz	transmission	138.00	69.00	12.98
10	Vale	distribution	69.00	13.00	
11					
12	Wyoming:				
13	Jim Bridger - attended	transmission	345.00	230.00	34.50
14					
15					
16					
17					
18					
19	Transformers-distribution substations under 10,000				
20	KVA 83 unattended.				
21					
22					
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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)	
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
50	3	1				14
80	1					15
69	3					16
15	1					17
254	2					18
42	2					19
75	3					20
240	2					21
67	3					22
450	3	1				23
8	3					24
18	1					25
25	1					26
25	1					27
180	1					28
		4				29
312	3					30
		1				31
		1				32
721	5	1				33
30	2					34
20	1					35
6	1	1				36
20	2					37
12	1					38
48	2					39
15	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
120	1					1
24	1					2
75	3					3
120	1					4
		1				5
15	1					6
15	1					7
12	1					8
15	2					9
4	1					10
48	2					11
4	1					12
12	2	1				13
4	1					14
48	2					15
		1				16
		6				17
		1				18
27	1					19
25	1					20
140	1					21
180	1					22
6	1					23
96	2					24
5	1					25
		1				26
108	6	3				27
26	1	1				28
67	5					29
118	7					30
160	2					31
17	1					32
36	2					33
38	2					34
24	1					35
18	1					36
18	1					37
24	1					38
15	1					39
8	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
8	1					1
17	1					2
15	1					3
15	1					4
24	1					5
25	1					6
18	2					7
10	1					8
2						9
15	2					10
10	1	1				11
15	1					12
50	3	1				13
20	1					14
17	1					15
8	1					16
10	1					17
15	2					18
10	1	1				19
24	1					20
5	2					21
48	2					22
24	1					23
10	1					24
5	1					25
20	1					26
18	1					27
12	1					28
25	1					29
600	3	1				30
20	1					31
8	1					32
18	1					33
39	2					34
24	1					35
		2				36
22	2					37
100	1					38
5	1					39
12	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
5	1					1
10	1					2
10	1					3
300	3					4
48	2					5
12	1					6
20	1					7
20	1					8
30	2					9
15	1					10
18	1					11
180	1					12
12	1					13
20	2					14
42	2					15
18	1					16
		7				17
180	1					18
180	1					19
600	3	1				20
12	1					21
18	1					22
15	1					23
10	1					24
18	1					25
15	1					26
18	1					27
180	1					28
246	2					29
12	1					30
12	1					31
12	1					32
10	1					33
33	2					34
48	2					35
360	2					36
16	1					37
70	4					38
10	1					39
12	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
18	1					1
36	2					2
24	2					3
24	2					4
120	1					5
840	2	1				6
750	3	1				7
24	1					8
100	4					9
8	3	1				10
29	2					11
36	1					12
12	1					13
15	1					14
24	1					15
6	1					16
8	1					17
6	3	1				18
15	1					19
		1				20
18	1					21
180	1					22
50	3					23
12	1					24
10	1					25
10	1					26
6	1					27
10	3					28
10	1					29
12	1					30
36	2					31
23	3					32
50	3					33
22	2					34
42	2					35
36	2					36
18	1					37
						38
18	1					39
		1				40

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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)	
14	2					1
18	1					2
15	2					3
15	1					4
10	1	3				5
10	3					6
		2				7
5	2					8
10	1					9
2	3					10
3	1					11
10	1					12
12	1					13
30	2					14
12	1					15
33	2					16
10	1					17
18	1					18
18	1					19
33	2					20
15	1					21
83	3					22
20	2					23
18	1					24
5	1					25
24	1					26
12	1					27
30	2					28
8	1					29
		1				30
18	1					31
44	2					32
33	2					33
9	1					34
72	1					35
8	1					36
36	4					37
44	2					38
18	1					39
24	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2014	Year/Period of Report End of 2013/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.
18	1					1
12	1	1				2
20	2					3
25	1					4
10	1					5
18	1					6
36	2					7
20	1					8
24	1					9
						10
						11
						12
						13
						14
30	3	1				15
						16
						17
	1					18
	1					19
	1					20
			Line Reactor	1	48	21
			Line Reactor	1	35	22
			Line Reactor	1	35	23
			Line Reactor	1	35	24
			Line Reactor	1	35	25
20	3	1				26
						27
						28
685	3					29
55	1					30
55	1					31
12	1					32
500	3					33
1	1					34
40	1					35
8	3	1				36
20	2					37
38	2					38
25	1	1				39
240	2					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (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.
50	2					1
		1				2
15	1					3
10	3	1				4
244	2					5
100	1					6
15	1					7
100	3	1				8
15	1					9
10	1					10
						11
						12
703	7					13
						14
						15
						16
						17
						18
						19
356						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						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) [ ] An Original (2) [X] A Resubmission	04/15/2014	End of 2013/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	578,132
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1
for
MULTI-STATE ELECTRIC COMPANIES
INDEX

PUC FORM 559 (11000) (04-07)

STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)..	2	$ 57,053,369	$ 50,406,870
3	Operating Expenses			
4	Operation Expenses (401)...	8-11	35,392,549	30,623,249
5	Maintenance Expenses (402)..	8-11	3,313,642	3,530,772
6	Depreciation Expense (403)..	12	5,290,169	4,863,271
7	Amort. & Depl. of Utility Plant (404-405)..	12	324,193	304,434
8	Amort. of Utility Plant Acq. Adj. (406)...	12	-	(533)
9	Amort. of Property Losses, Unrecovered Plant and Regulatory.............. Study Costs (407-411)	12	(1,723)	(8,111)
10	Accretion Expense (411)...	12	14,090	6,868
11	Amort. of Conversion Expenses (407)...	12		
12	Taxes Other Than Income Taxes (408.1)...	13	2,186,489	2,042,432
13	Regulatory Debits/Credits..	14	56,176	(748,954)
14	Income Taxes - Federal (409.1)..	14	(85,708)	(766,932)
15	- Other (409.1)..	15	137,781	36,314
16	Provision for Deferred Inc. Taxes (410.1)...	16-23	5,072,835	10,253,044
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1).....................	16-23	(2,894,629)	(8,577,258)
18	Investment Tax Credit Adj. - Net (411.4)..	24	(33,121)	372,045
19	(Less) Gains from Disp. of Utility Plant (411.6)...................................			
20	Losses from Disp. of Utility Plant (411.7)..			
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20).................		48,772,743	41,930,641
22	Net Utility Operating Income (Total of line 2 less 20)..........................		$ 8,280,627	$ 8,476,229

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) 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).
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.		OPERATING REVENUES		MEGAWATT HOURS SOLD		AVG NO OF CUSTOMERS PER MONTH		Line No.
	(a)	Amount for Current Year (b)	Amount for Previous Year (c)	Amount for Current Year (d)	Amount for Previous Year (e)	Number for Current Year (f)	Number for Previous Year (g)	
1	Sales of Electricity							1
2	(440) Residential Sales	$ 19,397,656	$ 16,344,607	197,839	185,122	13,350	13,319	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)	17,236,522	14,948,718	205,430	196,965	5,105	5,047	4
5	Large (or Industrial) (See Instr. 4) (2)	14,555,504	12,660,935	244,011	238,233	6	7	5
6	(444) Public Street and Highway Lighting	141,960	137,508	896	854	29	25	6
7	(445) Other Sales to Public Authorities							7
8	(446) Sales to Railroads and Railways							8
9	(448) Interdepartmental Sales							9
10	TOTAL Sales to Ultimate Consumers	51,331,642*	44,091,768*	648,176 **	621,174	18,490	18,398	10
11	(447) Sales for Resale - Opportunity Non-Firm	2,403,572	2,692,053	74,276	95,515			11
12	TOTAL Sales of Electricity	53,735,214	46,783,821	722,452	716,689	18,490	18,398	12
13	(Less) (449.1) Provision for Rate Refunds	(15,146)	(22,751)					13
14	TOTAL Revenue Net of Provision for Refunds	53,720,067	46,761,070					
15	Other Operating Revenues							
16	(450) Forfeited Discounts							
17	(451) Miscellaneous Service Revenues	74,976	88,930					
18	(453) Sales of Water and Water Power							
19	(454) Rent from Electric Property	1,150,868	1,112,988					
20	(455) Interdepartmental Rents							
21	(456) Other Electric Revenues	2,107,458	2,443,883					
22								
23								
24								
25	TOTAL Other Operating Revenues	3,333,302	3,645,801					
26	TOTAL Electric Operating Revenues	$ 57,053,369	$ 50,406,871					

* Includes $438,254 unbilled revenues.

** Includes -377 MWH relating to unbilled revenues.

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

(2) Commercial and Industrial sales - Large - 1,000 KW and over.

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the KWH of electricity sold, revenue, average number of customers, average KWH per customer, and average revenue per KWH, excluding data for Sales for Resale which is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable 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 (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	1 - Residential	196,228	$ 19,171,242	13,350	14,699	9.77
3	3 - Residential-Mastered Meterec					
4	84 - Residential-Net Metering					
5	15 - Dusk to Dawn customer Lighting	190	52,596			27.68
6	Residential - Billed	196,418	19,223,838	13,350	14,713	9.79
7	Residential - Unbilled	1,421	296,675	**1		20.88
8	Bridger Depr & Boardman Decomm		(122,857)			
9	**Total 440**	197,839	19,397,656	13,350	14,819	9.80
10						
11	442 - Commercial and Industrial Sales:					
12	7 - General Service	18,323	1,900,270	2,442	7,503	10.37
13	9 - General Service	134,383	10,178,112	897	149,814	7.57
14	84 - General Service-Net Metering					
15	15 - Dusk to dawn customer lighting	268	59,582	0		22.23
16	19 - Uniform rate contracts	245,980	14,752,830	6	40,996,667	6.00
17	24 - Irrigation and soil drainage pumping	52,265	5,034,707	1,764	29,629	9.63
18	40 - General Service	9	816	2	4,500	9.07
19	Commercial & Industrial - Billed	451,228	31,926,317	5,111	88,286	7.08
20	Commercial & Industrial - Unbilled	(1,787)	142,997	**1		(8.00)
21	Bridger Depr & Boardman Decomm		(277,288)			
22	**Total 442**	449,441	31,792,026	5,111	87,936	7.07
23						
24						
25	444 - Public Street and Highway Lighting:					
26	40 - General Service					
27	41 - Municipal street lighting	887	141,795	22	40,318	15.99
28	42 - Municipal traffic control signal lighting	21	1,973	7	3,000	9.40
29	Public Street & Highway lighting billec	908	143,768	29	31,310	15.83
30	Public St & Highway lighting-unbillec	(12)	(1,416)	**1		
31	Bridger Depr & Boardman Decomm		(392)			
32	**Total 444**	896	141,960	29	30,897	15.84
33						
34						
35						
36						
37						
38	Total Billed	648,554	50,893,386	18,490	35,076	7.85
39	Total Unbilled Rev. (See Instr. 6)	(378)	438,256	**1		
40	TOTAL	648,176	51,331,642	18,490	35,076	7.85

**1 Number of customers unknown.

ALLOCATED SALES FOR RESALE (Account 447) - STATE OF OREGON

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sales involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (L) and (p).

Line No.	Sales To (a)	Stat. Class. (b)	Export Across State Lines (c)	FERC Rate Sch. No. (d)	Point of Delivery (State or County) (e)	Station Owner-Ship (f)	MW or MVa of Demand (Specify which) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1									
2									
3	Various Utilities								
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
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21									
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24									
25									
26									
27									
28									
29									

ALLOCATED SALES FOR RESALE (Account 447) (Continued) - STATE OF OREGON

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
							1
							2
				2,403,572		$ 2,403,572	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
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SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required informatior
If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be groupe
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition t
other required information.
4. Designate associated companies
5. Provide subheading and total for each account

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per KWH (e)
1	None				
2					
3					
4					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amoun
included in this account represents profit or return on property, depreciation, and taxes, give particulars and th
basis of apportionment of such charges to Account 454 or 455.
4. Designate if lessee is an associated company
5. Provide a subheading and total for each account

Line No.	Name of Lessee or Departmen (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Renta	$ 491,823
22			
23	"	Transformer Rentals - Dist	705
24			
25	"	Line Rentals	98,655
26			
27	"	Cogeneration	44,251
28			
29	"	Pole Attachments	111,351
30			
31	"	Facilities Charges	379,775
32			
33	"	Other Rentals	24,308
34			
35	"	Miscellaneous	-
36			
37	"		
38	Total Account 454		$ 1,150,868

ALLOCATED SALES OF WATER AND WATER FOR POWER (Account 453) - OREGON

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for which Water was Used (b)	Power Plant Development (c)	Amount of Revenue for Year (d)
1	None			
2				
3		TOTAL		

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardles of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For account 456, list first revenues realized through Research and Development ventures, see account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues	$ 74,976
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 296,162
11	Transmission - Point-to-Point and Other	633,605
12	Photovoltaic Station Service	95
13	DSM Rider Funds	1,168,447
14	Sierra Pacific Usage Charge	5,858
15	Antelope	3,141
16	Miscellaneous	151
17		
18		
19		
20	Total Account 456	$ 2,107,458
21		
22		
23		

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes 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	$ 64,740	$ 56,456
5	(501) Fuel	$ 7,072,128	5,884,272
6	(502) Steam Expenses	390,099	362,224
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	76,826	67,345
10	(506) Miscellaneous Steam Power Expenses	402,195	335,331
11	(507) Rents	14,788	11,483
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	8,020,776	6,717,111
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	4,314	13,336
16	(511) Maintenance of Structures	27,079	30,548
17	(512) Maintenance of Boiler Plant	549,874	551,481
18	(513) Maintenance of Electric Plant	238,227	224,839
19	(514) Maintenance of Miscellaneous Steam Plant	192,800	201,098
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,012,295	1,021,302
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	9,033,071	7,738,412
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	256,767	301,181
45	(536) Water for Power	241,112	314,351
46	(537) Hydraulic Expenses	576,202	511,741
47	(538) Electric Expenses	61,353	56,436
48	(539) Miscellaneous Hydraulic Power Generation Expenses	206,146	106,020
49	(540) Rents	6,011	13,250
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,347,591	1,302,979

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON
If the amount for previous year is not derived from previously reported figures, explain in footnotes

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 3,558	$ 12,278
54	(542) Maintenance of Structures	60,594	53,494
55	(543) Maintenance of Reservoirs, Dams, and Waterways	48,749	54,068
56	(544) Maintenance of Electric Plant	112,454	128,915
57	(545) Maintenance of Miscellaneous Hydraulic Plant	127,602	123,614
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	352,957	372,369
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,700,549	1,675,348
61	Operation		
62	(546) Operation Supervision and Engineering	57,776	54,037
63	(547) Fuel	2,391,765	1,089,882
64	(548) Generation Expenses	147,915	89,337
65	(549) Miscellaneous Other Power Generation Expenses	24,865	16,235
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,622,321	1,249,491
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	4	-
70	(552) Maintenance of Structures	12,791	8,372
71	(553) Maintenance of Generating and Electric Plant	5,689	4,179
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	52,387	102,134
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	70,871	114,686
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	2,693,192	1,364,177
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	9,479,493	8,330,458
77	(556) System Control and Load Dispatching	59,581	91
78	(557) Other Expenses	2,432,425	795,178
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	11,971,500	9,125,727
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	25,398,311	19,903,664
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	151,469	144,450
84	(561) Load Dispatching	121,980	110,431
85	(562) Station Expenses	102,232	95,169
86	(563) Overhead Line Expenses	31,180	26,614
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	248,742	275,373
89	(566) Miscellaneous Transmission Expenses	2,109	7,088
90	(567) Rents	124,126	121,118
91	TOTAL Operation (Enter Total of lines 83 thru 90)	781,837	780,245
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	13,760	19,559
94	(569) Maintenance of Structures	32,011	30,864
95	(570) Maintenance of Station Equipment	153,560	148,813
96	(571) Maintenance of Overhead Lines	152,765	213,689
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	26	62
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	352,121	412,986
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,133,959	1,193,230
102	Operation		
103	(580) Operation Supervision and Engineering	179,946	176,597

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 143,636	$ 137,956
106	(582) Station Expenses	45,099	37,507
107	(583) Overhead Line Expenses	228,407	276,566
108	(584) Underground Line Expenses	35,897	29,290
109	(585) Street Lighting and Signal System Expenses	3,407	5,176
110	(586) Meter Expenses	154,311	148,347
111	(587) Customer Installations Expenses	53,223	51,250
112	(588) Miscellaneous Distribution Expenses	248,856	241,084
113	(589) Rents	15,836	21,145
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,108,618	1,124,918
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	7,304	9,612
117	(591) Maintenance of Structures	-	-
118	(592) Maintenance of Station Equipment	125,168	123,775
119	(593) Maintenance of Overhead Lines	1,063,863	1,136,009
120	(594) Maintenance of Underground Lines	9,647	16,389
121	(595) Maintenance of Line Transformers	11,675	16,422
122	(596) Maintenance of Street Lighting and Signal Systems	24,567	26,848
123	(597) Maintenance of Meters	26,193	26,058
124	(598) Maintenance of Miscellaneous Distribution Plant	32,613	42,304
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,301,031	1,397,417
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,409,649	2,522,335
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	21,625	20,637
130	(902) Meter Reading Expenses	171,657	194,024
131	(903) Customer Records and Collection Expenses	513,028	484,600
132	(904) Uncollectible Accounts	318,829	278,900
133	(905) Miscellaneous Customer Accounts Expenses	13	21
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	1,025,153	978,182
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	17,732	28,981
138	(908) Customer Assistance Expenses	1,424,249	1,825,126
139	(909) Informational and Instructional Expenses	9,651	10,853
140	(910) Miscellaneous Customer Service and Informational Expenses	19,190	29,888
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	1,470,822	1,894,848
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	3,046,421	3,175,326
152	(921) Office Supplies and Expenses	775,926	854,556
153	(922) Administrative Expenses Transferred-Credit	(1,184,437)	(1,273,980)

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 232,274	$ 233,597
156	(924) Property Insurance	153,195	139,391
157	(925) Injuries and Damages	250,890	322,641
158	(926) Employee Pensions and Benefits	3,186,046	3,056,715
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	374,351	736,844
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	21,895	22,246
163	(930.2) Miscellaneous General Expenses	187,092	181,689
164	(931) Rents	279	723
165	TOTAL Operation (Enter Total of lines 151 thru 164)	7,043,932	7,449,749
166	Maintenance		
167	(935) Maintenance of General Plant	224,366	194,683
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	7,268,298	7,661,762
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 38,706,191	$ 34,154,022

Line No.	SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 8,020,776	$ 1,012,295	$ 9,033,071
173	Nuclear power			
174	Hydraulic - Conventional	1,347,591	352,957	1,700,549
175	Hydraulic - Pumped Storage			
176	Other power	2,622,321	70,871	2,693,192
	Other Power Supply Expenses	11,971,500	-	11,971,500
177	Total Power Production Expenses	23,962,188	1,436,123	25,398,311
178	Transmission Expenses	781,837	352,121	1,133,959
179	Distribution Expenses	1,108,618	1,301,031	2,409,649
180	Customer Accounts Expenses	1,025,153	-	1,025,153
181	Customer Service and Informational Expenses	1,470,822	-	1,470,822
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	7,043,932	224,366	7,268,298
184	Total Electric Operation and Maintenance Expenses	$ 35,392,549	$ 3,313,642	$ 38,706,191

ALLOCATED DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) - OREGON
(Except amortization of acquistion adjustments)

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 324,193		$ 324,193
2	Steam Production Plant	1,008,878	-		1,008,878
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	574,351	-		574,351
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	720,696	-		720,696
7	Transmission Plant	814,325	-		814,325
8	Distribution Plant	1,754,655	-		1,754,655
9	General Plant	404,668	-		404,668
10	Depreciation on Disallowed Costs	(12,840)	-		(12,840)
11	Boardman ARO Depreciation	25,435			25,435
12	ARO Accretion	14,090			14,090
13	TOTAL	$ 5,304,259	$ 324,193		$ 5,628,452

B. OTHER AMORTIZATION

Describe briefly the nature of each transaction giving rise to amortization included in Account 406, Amortization of Utility Plant Acquisition Adjustments, or Account 407, Amortization of Property Losses. Provide the requested information for each transaction, as well as providing a total for each account.

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			$ -
Account 411			
411.6			$ (257)
411.7			287
411.8			(1,754)
			$ (1,723)

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 625,140
3	FUTA	4,072
4	Less: Payroll Deduction and Loading	(673,279)
5	State Taxes:	
6	Ad Valorem	1,110,877
7	Licenses - Hydro Projects	201
8	Regulatory Commission Fees	164,189
9	Franchise Taxes	859,269
10	State Unemployment Taxes	44,068
11	Hydro Generation KWH Tax	51,955
12	Canada Sales Tax	(2)
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,186,489

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amou are shown in thousands, show (000) in the heading for column (b

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as nega

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately ider adjustments arising from revisions of prior year accruals

4. Minor amounts of other additions (subtractions) may be groupe

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 57,053,369
2	Operations and Maintenance Expenses	38,706,191
3	Taxes Other Than Income	2,186,489
4	Regulatory Debits/Credits	56,176
5	State Income (Excise) Tax	197,196
6	Interest	3,793,750
7	Federal Income Tax Depreciation	5,290,169
8	Other Line items to Derive Taxable Income	14,090
9	Amortization of Limited-Term Plant	322,470
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 6,486,837
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 2,270,393
30	FIN 48 Adjustment	-
31	Prior Years' Tax Adjustment	823
32	Total Federal Income Tax Before Other Adjustment	2,271,216
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 962,070
36	Income Tax Adjustments	(7,696,139)
37	Federal Tax on Other Tax Adj @ 35%	(2,356,924)
38		
39	Total Federal Income Tax	$ (85,708)

CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE - Account 409.1

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 57,053,369
2	Operations and Maintenance Expenses	38,706,191
3	Taxes Other Than Income	2,186,489
4	Regulatory Debits/Credits	56,176
5	Interest	3,793,750
6	State Income (Excise) Tax Depreciation	5,290,169
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	322,470
	ARO Accretion Expense	14,090
10	Income Tax Adjustments	5,523,315
11	Allowance for AFUDC	(962,070)
12	IERCO Taxable Income	(178,673)
13		
14	State Tax Net Income	$ 2,301,461
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	197,196
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(59,416)
24		
25		
26	Total Oregon State Tax	$ 137,781

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
(a) identfy, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		32,884	0
4	Other Operating (See Note 1)		1,389,958	(1,749,702)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 1,422,842	$ (1,749,702)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 1,422,842	$ (1,749,702)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		4,007	0
	Executive Deferred Compensation Short-Term		7,490	(2,863)
	Executive Deferred Compensation Long-Term		13,418	(120)
	SFAS 112 - Post Retirement Benefits		8,408	0
	Non-VEBA Pension and Benefits		4,676	(0)
	FAS 123R - Stock Based Compensation		32,383	(45,674)
	Provision for Rate Refunds		401	(5,476)
	Revenue Sharing		58,963	(65,060)
	Montana NOL		422	(1,206)
	Oregon NOL		6,770	(6,244)
	Federal NOL		926,475	(323,888)
	Valmy Union Pacific Contract		8,088	(14,978)
	Deferred Idaho ITC		4,396	(59,713)
	VEBA - Post Retiree Benefits		3,468	(29,115)
	Bridger Revenue Deferral		0	(4,338)
	AFUDC Hells Canyon Relicensing		0	(180,102)
	Reg Liability		80,019	(83,638)
	Reg Asset		208,779	(868,762)
	Boardman Decommission		9,471	(4,368)
	CSPP Co-Generator Overpayment		0	(16,267)
	Oregon Pension Expense		8,096	(18,700)
	Deferred GBC Federal		(259)	0
	Asset Retirement Obligation (ARO)		4,487	(19,190)
	Total	$	$ 1,389,958	$ (1,749,702)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Debits		Credits			
(e)	(f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
82,804	(73,930)						6
							7
							8
$ 82,804	$ (73,930)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 82,804	$ (73,930)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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

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

2. In the space provided furnish explanations, including the following in columnar order:
(a) State each certification number with a brief description of property.
(b) Total and amortizable cost of such property.
(c) Date amortization for tax purposes commenced.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR Amounts Credited (Account 411.1) (d)
1	Accelerated Amortization (Account 281)	NONE		
2	Electric			
3	Defense Facilities......			
4	Pollution Control Facilities......			
5	Other: Accelerated Amortization......			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities......			
11	Pollution Control Facilities......			
12	Other......			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)......			
16	Other (Specify)......			
17	TOTAL (Account 281)(Enter Total of 8, 15, and 16)......		$ -	$ -
18				
19	Federal Income Tax......			
20	State Income Tax......			
21	Local Income Tax......			

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

(d) "Normal" depreciation rate used in computing the deferred tax.
(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
$ -	$ -						17
							18
							19
							20
							21

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. In the space provided furnish below explanations,including the following:
State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.,) estimated lives i.e. useful life, guideline life, guideline class life, etc., and classes of plant to

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 1,519,919	$ (214,670)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		1,519,919	(214,670)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 1,519,919	$ (214,670)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Line 2:			
Depr Federal Adj		1,450,481	(27,549)
Intangible Asset - Labor Deductions		(4,667)	-
N Valmy Partnership Capitalized Itmes		-	(3,268)
CIAC as Taxable Income		13,030	(180,477)
FERC Juris-S Georgia-Acct 282 Def only		-	-
Engineering Fees		0	(3,375)
Software Costs		61,075	-
Total		1,519,919	(214,670)

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

which each method is being applied and date method was adopted.

3.Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
$ -	$ -				$ -		2
							3
							4
0	0				0		5
							6
							7
$ -	$ -						8
$ -	$ -				$ -		9
							10
							11
							12
							13

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		2,130,074	(930,258)
3				
4	Total Electric..		2,130,074	(930,258)
5				
6				
7	Other (See Note 2)...			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)..........		$ 2,130,074	$ (930,258)
11	Classification of Total:			
12	Federal Income Tax..			
13	State Income Tax..			
14	Local Income Tax...			
	Note 1:			
	Oregon PCAM..		4,975	0
	FERC Grid West Expense..		0	(378)
	PCA		679,835	0
	Conservation Programs..		51,758	(1,807)
	Oregon Excess Power Supply Costs.............................		0	(29,988)
	OATT Revenue Deficiency		0	(9,306)
	Emission Allowances...		41	(176)
	Fixed Cost Adjustment (FCA).......................................		93,862	(11,260)
	OPUC Grid West Loans…………………………............		0	(192)
	Intervenor Funding Orders...		920	0
	Bonus Deferral...		0	(85)
	Reorganization Costs..		0	(3,119)
	Delivery Accruals...		30	(558)
	REC Sales..		37,929	(52,439)
	Pension Expense..		296,186	(340,903)
	LIDAR Surveys Deferral...		0	(590)
	Bennett Mtn Maintenance Deferral...............................		0	(1,013)
	Custom Efficiency Incentive Payment...........................		11,516	(189,613)
	Reg Liability...		83,638	(80,019)
	Reg Asset..		868,762	(208,779)
	Langley Revenue Deferral..		624	0
	PS&I Costs - Coal & CHP Plants - Write Off................		0	(34)
	Total...		2,130,074	(930,258)
	Note 2:			
	Advance Coal Royalties..			
	Oregon Non-Operating Property Tax Adj......................			
	Unrealized Gain/Loss from Rabbi Trust........................			
	Total...			

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

3. Beginning balances may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
3,539	(1,243)						7
							8
							9
$ 3,539	$ (1,243)		$ -		$ -		10
							11
							12
							13
							14

0	0
798	0
0	0
2,741	(1,243)
3,539	(1,243)

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 100,145	411.4	$ 133,265			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)......	$ 441,048,860	$ 441,048,860				
4	Property Under Capital Leases......						
5	Plant Purchased or Sold......						
6	Completed Construction not Classified......						
7	Experimental Plant Unclassified......						
8	TOTAL (Enter Total of lines 3 thru 7)......	$ 441,048,860	$ 441,048,860				
9	Leased to Others......						
10	Held for Future Use......	$ 89,977	$ 89,977				
11	Construction Work in Progress......	$ 39,339,876	$ 39,339,876				
12	Acquisition Adjustments......						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)......	$ 480,478,713	$ 480,478,713				
14	Accum. Prov. for Depr., Amort., & Depl......	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)......	$ 480,478,713	$ 480,478,713				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation......	NOT AVAILABLE					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights......						
20	Amort. of Underground Storage Land and Land Rights......						
21	Amort. of Other Utility Plant......						
22	TOTAL In Service (Enter total of lines 18 thru 21)......						
23	Leased to Others						
24	Depreciation......						
25	Amortization and Depletion......						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)......						
27	Held for Future Use						
28	Depreciation......						
29	Amortization......						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)......						
31	Abandonment of Leases (Natural Gas)......						
32	Amort. of Plant Acquisition Adj......						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)......						

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	241,023					241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	242,253	0	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	13,910,931	385,613	(5,420)			14,291,124	(311)	9
10	(312) Boiler Plant Equipment	40,718,619	822,609	(601,259)			40,939,969	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,561,393	8,228				13,569,621	(314)	12
13	(315) Accessory Electric Equipment	4,596,593	1,080	(3)			4,597,670	(315)	13
14	(316) Misc. Power Plant Equipment	1,711,738	81,397	(19,293)			1,773,842	(316)	14
15	(317) Asset Retirement Costs for Steam Production	3,815,938	259,641				4,075,579	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	78,421,822	1,558,568	(625,975)	0	0	79,354,415		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	11,041,270					11,041,270	(330)	27
28	(331) Structures and Improvements	17,835,617	1,411,769				19,247,386	(331)	28
29	(332) Reservoirs, Dams, and Waterways	91,309,867					91,309,867	(332)	29
30	(333) Water Wheels, Turbines, and Generators	22,969,288					22,969,288	(333)	30
31	(334) Accessory Electric Equipment	7,864,600	4,109,243	(5,982)			11,967,861	(334)	31
32	(335) Misc. Power Plant Equipment	3,838,020	110,315	(5,050)			3,943,285	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105					1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0					0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	156,246,767	5,631,327	(11,032)		0	161,867,062		35

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plan								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	234,668,589	7,189,895	(637,007)	0	0	241,221,477		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,574,524	$ 75,478				4,650,002	(350)	48
49	(352) Structures and Improvements	6,454,811	291,650	(571)			6,745,890	(352)	49
50	(353) Station Equipment	34,759,578	(1,567,712)	(245,570)			32,946,296	(353)	50
51	(354) Towers and Fixtures	14,667,497	169,281				14,836,778	(354)	51
52	(355) Poles and Fixtures	20,959,470	425,805	(182,953)			21,202,322	(355)	52
53	(356) Overhead Conductors and Devices	18,567,562	116,975	(60,183)			18,624,354	(356)	53
54	(357) Underground Conduit	0					0	(357)	54
55	(358) Underground Conductors and Devices	0					0	(358)	55
56	(359) Roads and Trails	48,566					48,566	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	100,032,009	(488,523)	(489,277)	0	0	99,054,209		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	148,192					148,192	(360)	60
61	(361) Structures and Improvements	1,211,524	9,536				1,221,060	(361)	61
62	(362) Station Equipment	7,114,482	363,200	(37,099)			7,440,583	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,731,893	329,370	(70,560)			17,990,703	(364)	64
65	(365) Overhead Conductors and Devices	8,149,383	423,427	(20,006)			8,552,804	(365)	65
66	(366) Underground Conduit	684,743	(9,783)	(2,490)			672,470	(366)	66
67	(367) Underground Conductors and Devices	3,145,242	(20,460)	(5,168)			3,119,614	(367)	67
68	(368) Line Transformers	40,931,039	1,989,029	(89,697)			42,830,371	(368)	68
69	(369) Services	2,864,039	(2,671)	(10,958)			2,850,410	(369)	69
70	(370) Meters	6,434,546	244,358	(40,042)			6,638,862	(370)	70
71	(371) Installations on Customer Premises	228,700	10,042	(9,605)			229,137	(371)	71
72	(372) Leased Property on Customer Premises	0					0	(372)	72
73	(373) Street Lighting and Signal Systems	212,682	1,017	(5,147)			208,552	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0					0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	88,856,465	3,337,065	(290,772)	0	0	91,902,758		75

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	485,108	10,790				495,898	(390)	78
79	(391) Office Furniture and Equipment	136,818	9,023	(815)			145,026	(391)	79
80	(392) Transportation Equipment	2,448,563	168,529	(82,510)			2,534,582	(392)	80
81	(393) Stores Equipment	4,866	(4,866)				0	(393)	81
82	(394) Tools, Shop and Garage Equipment	4,129	1,252				5,381	(394)	82
83	(395) Laboratory Equipment	78,779	1,656				80,435	(395)	83
84	(396) Power Operated Equipment	1,527,165	33,950				1,561,115	(396)	84
85	(397) Communication Equipment	3,864,836	(57,592)	(28,938)			3,778,306	(397)	85
86	(398) Miscellaneous Equipment	24,321		(5,144)			19,177	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	8,582,828	162,742	(117,407)	0	0	8,628,163		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	8,582,828	162,742	(117,407)	0	0	8,628,163		91
92	TOTAL (Accounts 101 and 106)	432,382,144	10,201,179	(1,534,463)	0	0	441,048,860		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 432,382,144	$ 10,201,179	$ (1,534,463)	$	$	$ 441,048,860		96

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

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

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page showing the account distributions of these tentative classifications in columns (c) and (d) including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	**INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.**			
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)				

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production				
19	Nuclear Production				
20	Hydraulic Production - Conventional				
21	Hydraulic Production - Pumped Storage				
22	Other Production				
23	Transmission				
24	Distribution				
25	General				
26	TOTAL (Enter Total of lines 18 thru 25)				

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)............			
2	Fuel Stock Expenses Undistributed (Account 152)............			
3	Residuals and Extracted Products (Account 153)............			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)............			
6	Assigned to - Operations and Maintenance............	INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.		
7	Production Plant (Estimated)............			
8	Transmission Plant (Estimated)............			
9	Distribution Plant (Estimated)............			
10	Assigned to - Other............			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)............			
12	Merchandise (Account 155)............			
13	Other Materials and Supplies (Account 156)............			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)............			
15	Stores Expense Undistributed (Account 163)............			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 217,020,169	$ 217,020,169				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	217,020,169	217,020,169				
9	Leased to Others						
10	Held for Future Use	$ 274,373	274,373				
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	217,294,543	217,294,543				
14	Accum. Prov. for Depr., Amort., & Depl.	$ 84,746,378	84,746,378				
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 132,548,165	$ 132,548,165				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	$ 83,848,914	$ 83,848,914				
19	Amort and Depl of Producing Natural Gas land and land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant	$ 897,464	897,464				
22	TOTAL In Service (Enter total of lines 18 thru 21)	84,746,378	84,746,378				
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)	$ 84,746,378	$ 84,746,378				

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization..........	$ 234					$ 244	(301)	2
3	(302) Franchises and Consents..........	1,164,443					1,252,078	(302)	3
4	(303) Miscellaneous Intangible Plant..........	1,283,848					1,367,084	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)..........	$ 2,448,525					$ 2,619,406		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights..........							(310)	8
9	(311) Structures and Improvements..........							(311)	9
10	(312) Boiler Plant Equipment..........							(312)	10
11	(313) Engines and Engine Driven Generators..........							(313)	11
12	(314) Turbogenerator Units..........							(314)	12
13	(315) Accessory Electric Equipment..........							(315)	13
14	(316) Misc. Power Plant Equipment..........							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment..........							(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)..........	$ 38,011,462					$ 41,056,036		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights..........							(320)	18
19	(321) Structures and Improvements..........							(321)	19
20	(322) Reactor Plant Equipment..........							(322)	20
21	(323) Turbogenerator Units..........							(323)	21
22	(324) Accessory Electric Equipment..........							(324)	22
23	(325) Misc. Power Plant Equipment..........							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production..........							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)..........								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights..........							(330)	27
28	(331) Structures and Improvements..........							(331)	28
29	(332) Reservoirs, Dams, and Waterways..........							(332)	29
30	(333) Water Wheels, Turbines, and Generators..........							(333)	30

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 34)	$ 28,873,314					$ 31,386,956		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights							(340)	37
38	(341) Structures and Improvements							(341)	38
39	(342) Fuel Holders, Products and Accessories							(342)	39
40	(343) Prime Movers							(343)	40
41	(344) Generators							(344)	41
42	(345) Accessory Electric Equipment							(345)	42
43	(346) Misc. Power Plant Equipment							(346)	43
44	(347) Asset Retirement Costs for Other Production							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 21,944,993					$ 23,601,196		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	88,829,769					96,044,189		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,431,831					1,532,053	(350)	48
49	(352) Structures and Improvements	2,823,425					2,975,567	(352)	49
50	(353) Station Equipment	14,736,411					16,543,436	(353)	50
51	(354) Towers and Fixtures	6,242,124					6,877,672	(354)	51
52	(355) Poles and Fixtures	4,876,460					5,513,805	(355)	52
53	(356) Overhead Conductors and Devices	7,449,474					8,009,224	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	15,707					16,568	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	$ 37,575,432					$ 41,468,324		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	135,100					135,100	(360)	60
61	(361) Structures and Improvements	1,122,872					1,134,552	(361)	61
62	(362) Station Equipment	6,145,688					6,453,594	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,731,892					17,990,702	(364)	64
65	(365) Overhead Conductors and Devices	8,149,382					8,552,804	(365)	65
66	(366) Underground Conduit	684,743					672,470	(366)	66
67	(367) Underground Conductors and Devices	3,145,241					3,119,614	(367)	67
68	(368) Line Transformers	17,534,952					19,204,415	(368)	68
69	(369) Services	2,864,040					2,850,412	(369)	69
70	(370) Meters	2,546,122					2,552,611	(370)	70
71	(371) Installations on Customer Premises	228,701					229,138	(371)	71

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises..........							(372)	72
73	(373) Street Lighting and Signal Systems..........	212,682					208,552	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant..........							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)..........	$ 60,501,415					$ 63,103,964		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights..........	662,247					708,271	(389)	77
78	(390) Structures and Improvements..........	3,847,454					4,397,456	(390)	78
79	(391) Office Furniture and Equipment..........	1,758,085					1,747,133	(391)	79
80	(392) Transportation Equipment..........	2,665,817					2,893,255	(392)	80
81	(393) Stores Equipment..........	77,144					81,541	(393)	81
82	(394) Tools, Shop, and Garage Equipment..........	265,623					307,448	(394)	82
83	(395) Laboratory Equipment..........	503,461					531,627	(395)	83
84	(396) Power Operated Equipment..........	472,272					546,861	(396)	84
85	(397) Communication Equipment..........	1,640,405					1,876,485	(397)	85
86	(398) Miscellaneous Equipment..........	230,974					245,072	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)..........	12,123,482					13,335,148		87
88	(399) Other Tangible Property *..........							(399)	88
89	(399.1) Asset Retirement Costs for General Plant..........							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)..........	12,123,482					13,335,148		90
91	TOTAL (Accounts 101 and 106)..........	201,478,623					216,571,031		91
92	(102) Electric Plant Purchased **..........								92
93	(Less) (102) Electric Plant Sold **..........								93
94	Asset Retirement Obligations (ARO)..........	436,967					449,138		94
95	TOTAL Electric Plant in Service..........	$ 201,915,590					$ 217,020,169		95

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

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

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page showing the account distributions of these tentative classifications in columns (c) and (d) including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year......	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense......	5,290,169	5,290,169		
4	(413) Exp. of Elec. Plt. Leas. to Others......				
5	Transportation Expenses-Clearing......				
6	Other Clearing Accounts......				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)......	5,290,169	5,290,169		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired......				
12	Cost of Removal......				
13	Salvage (Credit)......				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)......				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)......	$ 5,290,169	$ 5,290,169		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production......	$ 22,456,006	$ 22,456,006		
19	Nuclear Production......				
20	Hydraulic Production - Conventional......	16,052,942	16,052,942		
21	Hydraulic Production - Pumped Storage......				
22	Other Production......	2,470,511	2,470,511		
23	Transmission......	12,774,068	12,774,068		
24	Distribution......	25,332,902	25,332,902		
25	General......	4,309,850	4,309,850		
26	FAS 143 Adj &/or Disallowed Cost......	452,634	452,634		
27	TOTAL (Enter Total of lines 18 thru 26)......	$ 83,848,914	$ 83,848,914		

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)..	$ 2,199,546	$ 1,833,210	
2	Fuel Stock Expenses Undistributed (Account 152).........................			
3	Residuals and Extracted Products (Account 153)..........................			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated).......................................			
6	Assigned to - Operations and Maintenance................................			
7	Production Plant (Estimated)...	638,580	700,746	
8	Transmission Plant (Estimated)...	558,355	465,769	
9	Distribution Plant (Estimated)..	560,911	888,256	
10	Assigned to - Other..	51,713	54,464	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)...............	1,809,559	2,109,234	
12	Merchandise (Account 155)...			
13	Other Materials and Supplies (Account 156).................................			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)...			
15	Stores Expense Undistributed (Account 163)................................	192,644	186,915	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)………………	$ 4,201,749	$ 4,129,360	

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use)		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam............ Steam.....................................				
4	Nuclear..		22	Sales for Resale	
5	Hydro-Conventional..		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage..................................	**INFORMATION**	24	Energy Used by the Company (Excluding Station Use):	**INFORMATION**
7	Other...				
8	Less Energy for Pumping..............................	**NOT**	25	Electric Department Only	**NOT**
9	Net Generation (Enter Total of lines 3 thru 8)...	**AVAILABLE**	26	Energy Losses:	**AVAILABLE**
10	Purchases...		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)...		29	Unaccounted for Losses	
13	Out (gross)..		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13)....................		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWH)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17)....................				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18)...............................				

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchase plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be case of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amount of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated)
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	118.16	Tuesday	22	8 AM	60 Min. Int	67,161
34	February	98.90	Monday	11	8 AM	" " "	50,150
35	March	102.53	Monday	4	8 AM	" " "	56,323
36	April	80.76	Monday	29	11 AM	" " "	52,625
37	May	93.90	Monday	13	7 PM	" " "	52,414
38	June	115.92	Saturday	29	5 PM	" " "	62,300
39	July	127.05	Tuesday	2	4 PM	" " "	71,613
40	August	114.23	Wednesday	14	6 PM	" " "	69,589
41	September	96.91	Wednesday	4	5 PM	" " "	52,256
42	October	93.05	Wednesday	30	9 AM	" " "	54,988
43	November	104.01	Friday	22	8 AM	" " "	56,768
44	December	121.03	Monday	9	8 AM	" " "	61,682
45	TOTAL	1,266.45					707,869

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues	$ 418,795	$ 18,452	$ 400,343
2	Nuclear power research expenses (elec.)			
3	Other experimental and general research expenses			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent	352,652	15,538	337,114
7	Other expenses (items of $100 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $100 may be grouped by classes if the number			
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	752,654	33,161	719,493
14				
15	Miscellaneous general management expenses (see detail on page 39)	1,317,917	58,066	1,259,851
16				
17	Memberships and contributions (see detail on page 39)	1,404,353	61,875	1,342,478
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 4,246,371	$ 187,092	$ 4,059,279

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Directors' Fees and Expenses:			
2	Richard Dahl - Fees	$ 83,655	$ 3,686	$ 79,969
3	Richard Reiten - Fees and expenses	31,185	1,374	29,811
4	Christine King-Fees and expenses	81,029	3,570	77,459
5	Thomas Wilford - Fees and expenses	65,599	2,890	62,709
6	Jan Packwood-Fees and expenses	54,945	2,421	52,524
7	Judith Johansen-Fees and expenses	38,268	1,686	36,582
8	Joan Smith - Fees and expenses	77,098	3,397	73,701
9	Gary G Michael - Fees	60,555	2,668	57,887
10	Stephen Allred	68,310	3,010	65,300
11	Robert A Tinstman Fees and expenses	125,185	5,516	119,669
12	Ronald Jibson - Fees and expenses	19,305	851	18,454
13	Dennis Johnson - Fees and expenses	47,520	2,094	45,426
14	SUBTOTAL	752,654	33,161	719,491
15				
16	Miscellaneous General Management Expenses:			
17	Moody's Analytics Inc	31,382	1,383	29,999
18	CEB	41,116	1,812	39,304
19	Broadridge Financial Solutions	48,906	2,155	46,751
20	Deutche Bank	33,874	1,492	32,382
21	E Source	11,467	505	10,962
22	Wells Fargo Shareowner Services	99,355	4,377	94,978
23	Stock Based Compensation	603,819	26,604	577,215
24	Thomson Financial/Carson	47,072	2,074	44,998
25	Miscellaneous General Management Expenses:	155,420	6,848	148,572
26	Rate Related Amortization	230,656	10,163	220,493
27	PR Newswire	14,850	654	14,196
28	SUBTOTAL	1,317,917	56,684	1,229,851
29				
30	Memberships and Contributions:			
31	Associated Taxpayers of Idaho - Membership	23,000	1,013	21,987
32	Boston College Center for Corporation	5,000	220	4,780
33	Chamber of Commerce	131,010	5,772	125,238
34	Corporate Executive Board	41,750	1,839	39,911
35	Idaho Associaton of Commerce and Industry	14,000	617	13,383
36	Idaho Technology Council	10,000	441	9,559
37	Misc Memberships (9)	10,621	468	10,153
38	National Assoc of Directors	6,175	272	5,903
39	National HydroPower Association	32,507	1,432	31,075
40	North American Energy Standard	7,000	308	6,692
41	Northwest Power Pool	156,807	6,909	149,898
42	Pacific NW Utilities-Membership	38,869	1,713	37,156
43	Western Electricity Coordinating Council	897,334	39,536	857,798
44	Western Energy Institute	30,280	1,334	28,946
45	SUBTOTAL	1,404,353	153,102	3,321,822
46				
47	**TOTAL**	$ 3,474,924	$ 242,947	$ (242,947)

OFFICERS

1. Report below the name, title and salary for the year for each executive officer whose sal
is $50,000 or more. An "executive officer" of a respondent includes its president, secretar
treasurer, and vice president in charge of a principal business unit, division or functic
(such as sales, administration or finance) and any other person who performs simil
policy making functions

2. If a change was made during the year in the incumbent of any position, show name a
total remuneration of the previous incumbent, and date change in incumbency was ma

3. Utilities which are required to file similar data with the Securities and Exchang
Commission, may substitute a copy of item 4 of Regulation S-K identified

Line No.	Title (a)	Name of Officer (b)	Salary for yea Total	Oregon
1				
2	President and Chief Executive Officer …................................	J LaMont Keen (1)	715,000	31,502
3				
4	President & Chief Executive Officer….....................................	Darrel T Anderson (2)	500,000	22,030
5				
6	Executive Vice President, Operations......................................	Dan Minor	410,000	18,064
7				
8	Sr Vice President, General Counsel	Rex Blackburn	320,000	14,099
9				
10	Senior Vice President, Power Supply..	Lisa Grow	280,000	12,337
11				
12	Vice President, Finance and Treasurer …................................	Steven R. Keen (3)	280,000	12,337
13				
14	Vice President, Human Resources & Corp Sevices	Luci McDonald	250,000	11,015
15				
16	Vice President and Chief Information Officer….........................	Dennis Gribble (4)	230,000	10,134
17				
18	Vice President, Customer Operations	Warren Kline	240,000	10,574
19				
20	Vice President, Public Affairs..	Jeffrey Malmen	232,000	10,222
21				
22	Vice President Chief Risk Officer	Lori Smith	225,000	9,913
23				
24	Vice President Engineering and Operations	Vern Porter	220,000	9,693
25				
26	Vice President, Controller & Chief Accounting Officer..............	Ken Petersen (3)	205,000	9,032
27				
28	Vice President & Chief Information Officer ………………………	Lonnie Krawl (5)	200,000	8,812
29				
30	Vice President, Regulatory Affairs..	Gregory Said	195,000	8,592
31				
32	Corporate Secretary..	Patrick Harrington	176,000	7,754
33				
34	Assistant Treasurer (3)...	Naomi Crafton-Shankel (3	176,000	7,754
35	(1) Retired from position 12/31/2013			
36	(2) Appointed to position 1/1/2014			
37	(3) Appointed to position 11/21/2013			
38	(4) Retired 9/30/2013			
39	(5) Appointed to position 10/1/2013			

POLITICAL ADVERTISING

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
ACTUAL INCENTIVE TAX	426.400	$ 4,104
ASSOCIATED TAXPAYERS OF I	"	90
AVISTA CORP	"	348
BENEFITS FROM 232016	"	39,447
BERT BRACKETT FOR STATE SENATO	"	750
BLOOMBERG FINANCE LP	"	5,700
BRANDON HIXON FOR STATE REPRES	"	750
BRENT CRANE FOR STATE REPRESEN	"	500
BURLEY INN INC	"	300
BUSINESS INSTITUTE FOR	"	2,500
CANYON COUNTY REPUBLICANS	"	500
CHRISTY PERRY FOR STATE REPRES	"	500
CHUCK WINDER FOR STATE SENATE	"	750
CINDY AGIDIUS FOR STATE REPRES	"	500
CLIFFORD BAYER FOR STATE REPRE	"	750
COOLER PROMO ITEM	"	18
CORP INCENTIVE	"	365
CORP INCENTIVE FICA	"	28
CURT MCKENZIE FOR STATE SENATE	"	500
DRAKECOOPER	"	5,000
ELAINE SMITH FOR STATE	"	500
ERIC ANDERSON FOR STATE REPRES	"	500
EXEC INCENT PR YR ADJ	"	62
EXEC INCENTIVE	"	186,497
EXEC INCENTIVE FICA	"	2,704
FRED WOOD FOR STATE REPRESENTA	"	1,000
FRIENDS OF BILL HANSELL	"	1,000
FRIENDS OF MARK HAAS	"	2,000
GAYLE BATT FOR STATE REPRESENT	"	500
GRANT BURGOYNE FOR STATE REPRE	"	500
HAHN,RICHARD L	"	178,112
HOLLI WOODINGS FOR STATE REPR	"	500
HOLMES,SANDRA D	"	1,355
HOPKINS RODEN CROCKETT HANSEN	"	24,000
IDAHO ASSOC OF COMMERCE AND IN	"	6,714
IDAHO COUNCIL ON INDUSTRY	"	1,000
IDAHO DEMOCRATIC LEGISLATIVE C	"	750
IDAHO INAUGURATION CELEBRATION	"	2,500
	"	

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
IDAHO LEGISLATIVE ADVISOR	426.400	$ 350
IDAHO MINING ASSOCIATION	"	6,150
IDAHO PETROLEUM COUNCIL	"	2,500
IDAHO PRIOR APPROPRIATION DOCT	"	50,000
IDAHO PROSPERITY FUND	"	23,500
IDAHO STATE SOCIETY	"	13,595
IDAHO STATE UNIVERSITY	"	1,000
IDAHO WATER USERS ASSOCIA	"	1,700
JAMES HOLTZCLAW FOR STATE REPR	"	250
JANET TRUJILLO FOR STATE REPRE	"	500
JASON MONKS FOR STATE REPRESEN	"	250
JEFF THOMPSON FOR STATE REPRES	"	750
JIM GUTHRIE FOR STATE SENATE	"	750
JIM RICE FOR STATE SENATE	"	750
JOE PALMER FOR STATE REPRESENT	"	500
JOHN GOEDDE FOR STATE SENATE	"	750
JOHN KITZHABER FOR GOVERNOR	"	1,000
JOHN RUSCHE FOR STATE REPRESEN	"	1,000
JUDY BOYLE FOR STATE REPRESENT	"	500
JULIE VAN ORDEN FOR STATE REPR	"	500
KELLEY PACKER FOR STATE REPRES	"	500
KEN ANDRUS FOR STATE REPRESENT	"	500
LAWERENCE DENNY FOR STATE REPR	"	500
LEE HEIDER FOR STATE SENATE	"	750
LENORE BARRETT FOR STATE	"	500
LINDEN BATEMAN FOR STATE REPRE	"	500
LOBBY IDAHO, LLC	"	62,115
LUKE MALEK FOR STATE REPRESENT	"	500
MALMEN,JEFFREY L	"	300,602
MARC GIBBS FOR STATE REPRESENT	"	500
MCDONALD CARANO WILSON GOVERNM	"	5,806
MICHAEL LEWAN COMPANY	"	72,000
MICHELLE STENNETT FOR STATE SE	"	1,000
MIKE MOYLE FOR STATE REPRESENT	"	1,000
MINOR,DAN B	"	17,023
Misc Cash Acctg ID 0000272818	"	(109)
Misc Cash Acctg ID 0000273204	"	(109)
Misc Cash Acctg ID 0000281485	"	(20)

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
MISC CORRECTIONS 2	426.400	$ 17,334
Misc. October 13 Adjustment	"	(6,357)
MONTANA TAXPAYERS ASSOCIATION	"	200
NATIONAL HYDROPOWER ASSOC	"	9,710
NELSON COMMUNICATIONS ASSOC	"	2,350
ONECARD ACCRUAL	"	2,659
OTTER FOR IDAHO	"	5,000
OXBOW MESSHALL AND CREW	"	1,308
OXBOW MESSHALL/CREW QTRS	"	2,068
OXLEY & ASSOCIATES INC	"	65,000
PATTI ANNE LODGE FOR	"	750
PAYROLL ACCR REVERSAL	"	(92,920)
PAYROLL ACCRUAL	"	87,361
PAYROLL TAX ACCRUAL	"	6,098
PETE NIELSEN FOR STATE REPRESE	"	500
PHYLIS KING FOR STATE REPRESEN	"	250
REPUBLICAN HOUSE CAUCUS	"	750
Reversal-ONECARD ACCRUAL	"	(8,664)
REVERSE CORP EXEC INCENT	"	(2,026)
RICH WILLS FOR STATE REPRESENT	"	500
RICK YOUNGBLOOD FOR STATE REPR	"	750
ROBERT ANDERST FOR STATE REPRE	"	750
ROY LACEY FOR STATE SENATE	"	750
RUSSELL FULCHER FOR STATE SENA	"	750
SCOTT BEDKE FOR STATE REPRESEN	"	1,000
SENATE REPUBLICAN PAC	"	250
SHEPHERD,CODY W	"	329
STEPHEN HARTGEN FOR STATE REPR	"	500
STEVEN HARRIS FOR STATE REPRES	"	250
Stock Based Compensation	"	128,605
TERRY GESTRIN FOR STATE REPRES	"	500
TODD LAKEY FOR STATE SENATE	"	750
TOM LOERTSCHER FOR STATE REPRE	"	500
TREASURE VALLEY LEGISLATIVE AG	"	2,500

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
WENDY HORMAN FOR STATE REPRESE	426.400	$ 500
WICHER,THOMAS D	"	6,357
WIR TELECOM ALLOC CHRG	"	197
WIR TELECOM DIR CHRG	"	1,834
WIRELESS TEL PR DEDUCT	"	(260)
Total Political Contributions		$ 1,282,131

EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest." Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
Idaho Power does not have any expenditures to its affiliated companies			

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP	426.101	$ 169,129	None
COLLEGE OF SOUTHERN IDAHO	"	3,000	"
IDACORP EMPLOYEES	"	50,871	"
Total Matching Employee Community Service Fund		**223,000**	
AGELESS SENIOR CITIZENS	426.102	250	"
ALZHEIMER'S OF IDAHO	"	50	"
AMERICAN CANCER SOCIETY	"	250	"
AN AMERICAN VETERAN TRIBUTE	"	1,000	"
BOISE BASIN BOOSTERS	"	400	"
BOISE BASIN SENIOR CENTER	"	230	"
BOISE CENTENNIAL ROTARY CLUB	"	750	"
BOISE RESCUE MISSION	"	6,000	"
BOY SCOUTS OF AMERICA	"	417	"
BOYS & GIRLS CLUB OF ADA CO	"	500	"
CANYON COUNTY FESTIVAL	"	2,178	"
CASCADE MEDICAL CENTER	"	250	"
CHAMBER OF COMMERCE	"	600	"
CHILDREN'S HOME SOCIETY OF ID	"	1,150	"
COMMUNITY CONNECTION OF BAKER	"	225	"
CRISIS CENTER OF MAGIC VALLEY	"	250	"
DESIGNS BY DE	"	1,913	"
DRESS FOR SUCCESS	"	140	"
ELKS MEALS IN WHEELS	"	750	"
FESTIVAL OF TREES	"	1,025	"
GARDEN CITY POLICE OFFICER'S A	"	500	"
GIRL SCOUTS OF SILVER SAGE COU	"	3,000	"
GLANBIA CHARITY CHALLENGE	"	250	"
GOODING SENIOR CENTER	"	250	"
HUFFMAN,TERESA A	"	132	"
IDAHO FOOD BANK	"	500	"
IDAHO FOODBANK	"	2,350	"
IDAHO RONALD MCDONALD HOUSE	"	2,000	"
IDAHO STATE UNIVERSITY	"	300	"
JEROME SENIOR CENTER	"	250	"
LIFE'S KITCHEN	"	1,000	"
LIGHTHOUSE RESCUE MISSION	"	1,000	"
LIONS CLUB	"	50	"
MAIN STREET MILE	"	3,000	"
MAN UP CRUSADE	"	150	"
MCPAWS REGIONAL ANIMAL SHELTER	"	200	"
MERIDIAN POLICE DEPARTMENT	"	400	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
MISC CORRECTIONS	426.102	$ 20	None
MISC CORRECTIONS 3	"	20	"
NATIONAL FEDERATION OF THE BLI	"	500	"
NORTHWEST CHILDREN'S HOME	"	1,000	"
OLMSTEAD,DANIEL H	"	200	"
OWYHEE COUNTY SHERIFF	"	750	"
PINE SENIOR CENTER	"	100	"
POE,VANCE T	"	200	"
ROTARY CLUB OF TWIN FALLS	"	350	"
SAINT ALPHONSUS FOUNDATION	"	500	"
SALVATION ARMY	"	1,000	"
SHOP WITH A COP ASSOCIATION	"	500	"
SHRINER HOSPITALS FOR CHILDREN	"	1,000	"
SMITH,DANIEL R	"	80	"
SNAKE RIVER SHRINE CLUB	"	250	"
SOUTH CENTRAL COMMUNITY	"	100	"
ST ALPHONSUS FESTIVAL OF TREES	"	9,000	"
ST LUKES HEALTH FOUNDATION	"	5,450	"
ST LUKES MCCALL FOUNDATION	"	500	"
THE SALVATION ARMY	"	1,000	"
THREE ISLAND PANTRY	"	200	"
TWIN FALLS OPTIMIST CLUB	"	150	"
TWIN FALLS SENIOR CENTER	"	500	"
WEST END SENIOR CITIZENS	"	250	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
WILDLAND FIREFIGHTER BENEFIT &	"	100	"
TOTAL HEALTH & HUMAN SERVICES		**58,380**	
4-H CLUB	426.103	250	"
4-H MARKET STOCK SALE	"	200	"
4-H YOUTH DEVELOPMENT	"	500	"
ABERDEEN GEM TRAIL	"	550	"
ADA COUNTY HIGHWAY DISTRICT	"	500	"
AFRICAN COMMUNITY DEVELOPEMENT	"	500	"
AIR FORCE APPRECIATION DAY	"	100	"
AMERICAN HEART ASSOCIATION	"	2,500	"
AMERICAN RED CROSS OF GREATER	"	2,500	"
ASSOC OF OREGON ARCHAEOLOGISTS	"	250	"
BAKER CITY BRONC & BULL RIDING	"	125	"
BAKER COUNTY FAIR - HALFWAY	"	666	"
BAKER COUNTY SHRINE CLUB	"	250	"
BAKER COUNTY Y M C A	"	3,000	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
BIG WATER BLOWOUT RIVER FESTIV	426.103	$ 200	None
BINGHAM COUNTY FAIR 4H MARKET	"	344	"
BLANKET PROMO ITEM	"	96	"
BOISE COUNTY COMMUNITY JUSTICE	"	250	"
BOISE PUBLIC SCHOOLS	"	100	"
BOISE RIDGE RIDERS	"	150	"
BOISE RIVER SWEEP	"	750	"
BOISE YOUNG PROFESSIONALS	"	100	"
BOY SCOUTS OF AMERICA	"	167	"
BOYS & GIRLS CLUB OF ADA CO	"	1,500	"
BOYS AND GIRLS CLUB OF WESTERN	"	1,500	"
BUHL, CITY OF	"	750	"
CAMBRIDGE RODEO ASSOCIATI	"	100	"
CANYON COUNTY FRATERNAL ORDER	"	250	"
CANYON COUNTY MARKET LIVESTOCK	"	500	"
CASTLEFORD MENS CLUB	"	300	"
CENTURY HIGH SCHOOL GRAD PARTY	"	75	"
CHAMBER OF COMMERCE	"	9,925	"
CHANCE,CINDY	"	21	"
CHAPSTICK W/CLIP	"	233	"
CHRISTMAS ON THE CANYON	"	500	"
CITY CLUB OF BOISE	"	150	"
CITY OF BOISE	"	750	"
CITY OF RICHLAND	"	250	"
COOLER PROMO ITEM	"	287	"
COULTER,LAVELLE E	"	80	"
COWBOY TRAILS AND TALES, INC	"	75	"
DAVEY TREE SURGERY COMPANY	"	159	"
DODSON,LAYNE M	"	500	"
DONNELLY CITY	"	150	"
DUCKS UNLIMITED	"	2,500	"
DUDGEON,MELISSA L	"	8	"
EAGLE KIWANIS	"	250	"
EAGLE LIONS CLUB	"	100	"
EARLY BIRDIES GOLF INVITATIONA	"	150	"
ELKS LODGE	"	100	"
ELMORE MEDICAL CENTER FOUNDATI	"	250	"
FLASHLIGHT PROMO	"	179	"
FOSDICK GOLF TOURNAMENT	"	400	"
FOUR-SUMMIT CHALLENGE	"	200	"
FRIENDS OF BOISE BASIN LIBRARY	"	200	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
FRIENDS OF THE WEISER RIVER	426.103	$ 250	None
FRIENDS OF ZOO BOISE	"	2,500	"
FRUITLAND COMMUNITY EVENTS	"	300	"
FUNDSY	"	500	"
GARDEN CITY LIBRARY FOUNDATION	"	500	"
GEM COUNTY SHERIFF POSSE	"	200	"
GLOBAL TRAVEL	"	5,000	"
GOD & COUNTY FAMILY FESTIVAL	"	250	"
GOLD DUST RODEO	"	500	"
GOLF BALLS	"	278	"
GOLF FOR A CAUSE	"	100	"
GRAND VIEW CITY	"	600	"
HANSEN,ERIC D	"	44	"
HAZELTON CEMETERY DISTRICT	"	100	"
HELLS CANYON DUCKS UNLIMITED	"	200	"
HOMAN,WILLIAM B	"	100	"
HORSESHOE BEND CITY	"	800	"
HORSESHOE BEND VOLUNTEERS	"	200	"
HUNTINGTON LIONS CLUB	"	250	"
IDAHO ASSOCIATION OF COUNTIES	"	150	"
IDAHO BOTANICAL GARDEN	"	3,000	"
IDAHO CHAPTER AMERICAN	"	850	"
IDAHO CHAPTER OF THE	"	500	"
IDAHO CITY MANAGERS ASSOCIATIO	"	500	"
IDAHO COMMISSION ON HISPA	"	1,500	"
IDAHO COMMUNITY FOUNDATION	"	2,500	"
IDAHO COUNCIL OF GOVERNMENTS	"	1,200	"
IDAHO HUMAN RIGHTS	"	1,000	"
IDAHO HUMANE SOCIETY	"	13,000	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO SENIOR GAMES	"	500	"
IDAHO STATE HISTORICAL SOCIETY	"	500	"
IDAHO STATE UNIVERSITY	"	2,900	"
JEROME COUNTY FAIR	"	250	"
JORDAN VALLEY JUNIOR RODEO	"	150	"
KETCHUM WAGON DAYS	"	250	"
KIWANIS CLUB OF NAMPA	"	100	"
KIWANIS CLUB OF ONTARIO	"	250	"
KIWANIS CLUB OF POCATELLO	"	75	"
KIWANIS CLUB OF TREASURE VALLE	"	200	"

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KNIFE 7 IN 1, S.S.	426.103	$ 117	None
KUNA YOUTH SOFTBALL & BASEBALL	"	250	"
LAWRENCE, MARGUERITE	"	900	"
LEMHI COUNTY JUNIOR LIVESTOCK	"	350	"
LIONS CLUB	"	230	"
LIONS CLUB, MOUNTAIN HOME	"	100	"
LUPO,MARK J	"	3,252	"
MALHEUR COUNTY JUNIOR LIVESTOC	"	592	"
MCPAWS REGIONAL ANIMAL SHELTER	"	1,000	"
MEADOWS VALLEY COMMUNITY FOUND	"	100	"
MERIDIAN FFA CHAPTER	"	750	"
MERIDIAN OPTIMIST CLUB	"	100	"
MERIDIAN, CITY OF	"	750	"
MISC CORRECTIONS	"	459	"
MOUNTAIN HOME FIRE DEPARTMENT	"	300	"
MOUNTAIN HOME OFFICERS SPOUSES	"	200	"
MUG	"	30	"
MUSICIANS' FUND OF BOISE INC	"	1,200	"
NEIGHBORHOOD HOUSING	"	3,500	"
neon highliter with Ipco logo	"	50	"
NO OR MULTIPLE DESC	"	377	"
NORTH BANNOCK COUNTY FAIR	"	150	"
NYSSA, CITY OF	"	200	"
OAKLEY VIGILANTEES	"	250	"
OWYHEE BUTTER TOFFEE	"	1,958	"
OWYHEE COUNTY HORSE 4-H LEADER	"	200	"
OWYHEE COUNTY JUNIOR LIVESTOCK	"	400	"
PAOLI,CHERYL S	"	500	"
PAYETTE COUNTY FAIR	"	400	"
PAYETTE COUNTY RODEO	"	150	"
PEARSON,JOSHUA W	"	200	"
PENCIL	"	32	"
PEREGRINE FUND INC, THE	"	2,500	"
PHETMISAY,TONJA I	"	120	"
POCATELLO / CHUBBUCK SCHOOL DI	"	1,500	"
POCATELLO H.S.	"	75	"
POE,VANCE T	"	148	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
POWER COUNTY 4 H/FFA LIVE	"	500	"
PRO LETTER OPENER	"	53	"
PROM MUG 16 0Z	"	268	"
PROMO ROAD SIDE SAFETY KITS	"	1,410	"
PROMO SEWING KIT	"	26	"
PROMO TOTE BAG	"	17	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
Reversal-ONECARD ACCRUAL	426.103	$ (9)	None
ROCKY MOUNTAIN ELK FOUNDATION	"	1,000	"
ROTARY CLUB	"	800	"
ROTARY CLUB OF	"	100	"
ROTARY CLUB OF NAMPA	"	750	"
ROTARY CLUB OF TWIN FALLS	"	250	"
ROTARY CLUB, BOISE	"	250	"
ROTARY CLUB, BOISE-SUNRIS	"	1,000	"
ROTARY CLUB, HAILEY	"	500	"
ROTARY DISTRICT 5400	"	250	"
SAWTOOTH RANGERS RIDING CLUB	"	100	"
SHEPHERD'S HOME INC	"	200	"
SIMPLOT GAMES	"	42	"
SMART WOMEN, SMART MONEY INC	"	2,500	"
SOUTH CENTRAL COMMUNITY	"	500	"
SOUTHEAST IDAHO SENIOR GAMES	"	500	"
SOUTHERN IDAHO TOURISM	"	250	"
SPORTS BOTTLE - PROMO	"	30	"
STAR QUILT SHOW	"	125	"
STAR, CITY OF	"	750	"
SUPPORTING ALL VOLUNTEER EMERG	"	100	"
TABLE ROCK CHALLENGE	"	400	"
THE GOOD SAMARITAN HOME	"	500	"
THERMOS SSL	"	323	"
THREE ISLAND DAYS	"	300	"
TRAILING OF THE SHEEP FESTIVAL	"	250	"
TREASURE VALLEY NAACP	"	1,500	"
TROUT UNLIMITED	"	1,500	"
TWIN FALLS COMMUNITY FOUNDATIO	"	500	"
TWIN FALLS COUNTY FAIR FOUNDAT	"	500	"
TWIN FALLS KIWANIS FOUNDATION	"	100	"
TWIN FALLS RAPIDS SOCCER CLUB	"	250	"
TWIN FALLS ROTARY FOUNDATION	"	2,000	"
VETERANS DAY PARADE COMMITTEE	"	500	"
VETERANS PARK NEIGHBORHOOD ASS	"	1,500	"
WALLOWA SOIL & WATER CONSERVAT	"	500	"
WASHINGTON COUNTY 4H/FFA	"	250	"
WASHINGTON COUNTY FAIR BOARD	"	696	"
WATER BOTTLE PROMO ITEM	"	106	"
WATSON,BLAKE J	"	39	"
WEWERS,BRYAN J	"	1,177	"
WILDLAND FIREFIGHTER BENEFIT &	"	50	"
WILLER,MELANIE J	"	13	"
WOMEN'S & CHILDREN'S ALLIANCE	"	6,000	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
WYAKIN WARRIOR FOUNDATION	426.103	$ 4,500	None
YBARGUEN,MICHAEL D	"	118	"
YELLOW PINE VETERANS MEMORIAL	"	200	"
YOYO	"	32	"
TOTAL CIVIC & COMMUNITY		**142,443**	
ADAMS COUNTY FAIR	426.104	300	"
BASQUE MUSEUM AND CULTURAL CEN	"	2,500	"
BOISE ART MUSEUM	"	3,000	"
BOISE CONTEMPORARY THEATER INC	"	1,000	"
BOISE MUSIC WEEK	"	1,000	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"
CHAMBER OF COMMERCE	"	500	"
COMMUNITY CONCERTS OF	"	250	"
CORNUCOPIA ARTS COUNCIL	"	250	"
CROSSROADS CARNEGIE ART CENTER	"	300	"
DREXEL H FOUNDATION	"	200	"
IDAHO HUMANITIES COUNCIL	"	600	"
IDAHO SHAKESPEARE FESTIVAL	"	3,000	"
IDAHO STATE CIVIC SYMPHONY	"	110	"
IDAHO WATERCOLOR SOCIETY	"	300	"
JORDAN VALLEY OWYHEE HERITAGE	"	250	"
LOG CABIN LITERARY CENTER	"	1,500	"
MCCALL ARTS & HUMANITIES COUNC	"	150	"
MERIDIAN ARTS COMMISSION	"	700	"
MERIDIAN SYMPHONY ORCHESTRA	"	750	"
MOUNTAIN HOME	"	400	"
MOUNTAIN HOME HISTORICAL SOCIE	"	150	"
NAMPA PARKS AND RECREATIONS	"	350	"
OWYHEE COUNTY HISTORICAL SOCIE	"	250	"
THE SUN VALLEY BALLET SCHOOL	"	100	"
TOTAL CULTURE & ARTS		**20,410**	
IDAHO PUBLIC TELEVISION	426.105	20,000	"
TOTAL PUBLIC TV & RADIO		**20,000**	
4-H TEAM DIRT TRACK MASTERS	426.106	250	"
AMERICAN CANCER SOCIETY	"	100	"
BLAZING HOPE YOUTH	"	100	"
BOGUS BASIN SNOWSCHOOL	"	100	"
BOISE CITY PARKS AND RECREATIO	"	100	"
BOISE STATE PUBLIC RADIO	"	100	"
BOY SCOUTS OF AMERICA	"	1,000	"
CAMP WILSON	"	500	"
CAPITAL CITY KIWANIS	"	100	"
CARRIBOO CONSERVANCY, INC	"	100	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
CHUBBUCK BOYS BASEBALL	426.106	$ 100	None
CRISIS CENTER OF MAGIC VALLEY	"	500	"
DUCKS UNLIMITED	"	100	"
EAST END PROVIDERS	"	100	"
IDAHO BOTANICAL GARDEN	"	100	"
IDAHO HUMANE SOCIETY	"	100	"
IDAHO STATE UNIVERSITY	"	100	"
JAPANESE AMERICAN	"	100	"
KUNA HIGH SCHOOL FOOTBALL BOOS	"	100	"
MISSION AVIATION FELLOWSHIP	"	100	"
MONROE ELEMENTARY SCHOOL	"	100	"
NEIGHBORHOOD HOUSING	"	100	"
POCATELLO CHIEFS, THE	"	100	"
POCATELLO MARATHON	"	100	"
POCATELLO RELAY FOR LIFE EVENT	"	100	"
PORTNEUF VALLEY PAINTFEST	"	100	"
ROTARY CLUB, BOISE-SUNRIS	"	100	"
SALMON SEARCH AND RESCUE	"	100	"
SALMON VOLUNTEER FIRE DEPT	"	250	"
SALMON YOUTH HOCKEY ASSOC	"	100	"
SIMPLOT GAMES	"	100	"
SKYVIEW MARCHING BANK	"	100	"
SUNRISE ROTARY OF CANYON COUNT	"	100	"
TEAM T R U E	"	100	"
TREASURE VALLEY DOWN SYNDROME	"	100	"
TWIN FALLS COUNTY YOUTH BASEBA	"	100	"
UNIVERSITY OF IDAHO	"	100	"
VALLEY WIDE REACT TEAM 4956	"	100	"
WOMEN'S & CHILDREN'S ALLIANCE	"	100	"
TOTAL VOLUNTEER INVOLVEMENT PROGRAM		**5,900**	
SALVATION ARMY	426.107	39,431	"
TOTAL PROJECT SHARE		**39,431**	
DUCKS UNLIMITED	426108	325	"
IDAHO ASSOCIATION OF SOIL	"	200	"
IDAHO BOWFISHING ASSOCIATION	"	200	"
LAKE CASCADE STATE PARK	"	100	"
MISC CORRECTOINS 5	"	(400)	"
MOUNTAIN HOME, CITY OF	"	400	"
SOUTHERN IDAHO TOURISM	"	250	"
WILDERNESS SCIENCE EDUCATION	"	150	"
WILDLAND FIREFIGHTER BENEFIT &	"	100	"
TOTAL ENVIRONMENT & CONSERVATION		**1,325**	

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BRIDGER COAL COMPANY	426.109	$ 5,000	None
IDAHO FOODBANK	"	100	"
IDAHO GOVERNERS CUP	"	16,500	"
MARYLHURST UNIVERSITY OFFICE O	"	3,000	"
SMART WOMEN, SMART MONEY INC	"	2,500	"
UNITED WAY OF TREASURY VALLEY	"	3,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	15,000	"
TOTAL NON-PROGRAM		**45,100**	
4-H FFA JUNIOR LIVESTOCK SALE	426.110	502	"
4-H MARKET SALE	"	400	"
ABERDEEN DISTINGUISHED YOUNG W	"	150	"
BLACKFOOT HIGH SCHOOL	"	400	"
BLACKFOOT SCHOOL DISTRICT	"	400	"
BOISE PUBLIC SCHOOLS	"	1,000	"
BOISE SCHOOLS FOUNDATION	"	5,000	"
BOISE STATE UNIVERSITY	"	1,000	"
BOISE STATE UNIVERSITY COLLEGE	"	2,000	"
BOY SCOUTS OF AMERICA	"	167	"
BRUNEAU ELEMENTARY SCHOOL	"	200	"
CANYON COUNTY VANDAL BOOSTER	"	125	"
CANYON RIDGE HIGH SCHOOL SENIO	"	75	"
CASCADE PUBLIC SCHOOLS	"	100	"
CHAMBER OF COMMERCE	"	850	"
CHAMBER OF COMMERCE, BOIS	"	200	"
COLLEGE OF IDAHO	"	3,000	"
COLLEGE OF WESTERN IDAHO	"	1,000	"
COLLEGE OF WESTERN IDAHO FOUND	"	3,000	"
COSSA EDUCATION ASSOCIATION	"	200	"
COUNCIL SCHOOL DISTRICT	"	100	"
DISCOVERY CENTER OF IDAHO	"	1,000	"
DISTRICT FOUR HIGH SCHOOL RODE	"	250	"
DOWNTOWN BOISE ASSOCIATION	"	500	"
DUDGEON,MELISSA L	"	178	"
EAGLE HIGH SCHOOL GRAD ALL-NIG	"	100	"
FLASHLIGHT PROMO	"	63	"
FUTURE FARMERS OF AMERICA	"	500	"
GEM BOISE COUNTY FAIR	"	500	"
GEM STATE FLY FISHERS	"	200	"
GLENNS FERRY HIGH SCHOOL	"	100	"
GOODING HIGH SCHOOL	"	50	"
GRAND VIEW YOUTH NIGHT	"	100	"
IDAHO ACADEMIC DECATHLON	"	1,250	"
IDAHO COUNCIL ON INDUSTRY	"	250	"
IDAHO FOOD BANK	"	300	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
IDAHO STATE UNIVERSITY	426.110	$ 4,125	None
IDAHO STATE UNIVERSITY HONORS	"	500	"
IDAHO TECH CONNECT	"	1,000	"
JALEPENO OPEN	"	250	"
JEROME HIGH SCHOOL SENIOR	"	50	"
JUNIOR ACHIEVEMENT OF IDAHO	"	2,000	"
LUPO,MARK J	"	424	"
MAYORS COMMUNITY SRVC SCHLRSHP	"	500	"
MCCALL FOLKLORE SOCIETY	"	100	"
MERIDIAN EDUCATION FOUNDATION	"	125	"
MERIDIAN FFA CHAPTER	"	250	"
MOUNTAIN HOME HIGH SCHOOL	"	200	"
MOUNTAIN HOME OPTIMIST	"	250	"
NAMPA HIGH PROJECT GRADUATION	"	100	"
NAMPA MAYOR'S TEEN COUNCIL	"	250	"
NEWSPAPERS IN EDUCATION	"	300	"
NORTHEAST OREGON AREA HEALTH E	"	240	"
NORTHWEST NAZARENE UNIVERSITY	"	4,000	"
OPTIMIST CLUB OF MCCALL	"	100	"
PAYETTE HIGH SCHOOL SENIOR	"	100	"
PROJECT GRADUATION	"	100	"
RACE TO THE SUMMIT	"	300	"
ROTARY CLUB	"	350	"
ROTARY CLUB OF BUHL	"	100	"
ROTARY CLUB OF JEROME	"	150	"
ROTARY CLUB, BOISE	"	500	"
S O S MENTORING PROGRAM	"	250	"
SOCIETY OF WOMEN ENGINEERS	"	2,000	"
SOUTHEASTERN IDAHO COMMUNITY	"	300	"
ST PAUL'S CATHOLIC SCHOOL	"	250	"
STATE OF IDAHO DEPARTMENT OF E	"	1,000	"
TREASURE VALLEY COMMUNITY COLL	"	3,000	"
TREASURE VALLEY SOCIETY OF HIS	"	100	"
TWIN FALLS SCHOOL FOUNDATION	"	150	"
UNIVERSITY OF IDAHO	"	300	"
UPPER COUNTRY EDUCATION FOUNDA	"	200	"
VALLIVUE SECURE & SOBER GRAD N	"	100	"
TOTAL EDUCATION		**49,224**	
BIG BEND COMMUNITY COLLEGE	426.111	2,000	"
BOISE STATE UNIVERSITY	"	4,333	"
BRIGHAM YOUNG UNIVERSITY	"	9,000	"
BRIGHAM YOUNG UNIVERSITY - HAW	"	4,000	"
BRIGHAM YOUNG UNIVERSITY CES A	"	2,000	"
BRIGHAM YOUNG UNIVERSITY FINAN	"	3,000	"

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COLLEGE OF IDAHO	426.111	$ 4,000	None
COLLEGE OF SOUTHERN IDAHO	"	2,000	"
COLLEGE OF WESTERN IDAHO	"	2,000	"
COLORADO STATE UNIVERSITY	"	2,000	"
IDAHO STATE UNIVERSITY	"	8,000	"
Misc Cash Acctg ID 0000273863	"	(1,333)	"
Misc Cash Acctg ID 0000291495	"	(1,000)	"
OREGON STATE UNIVERSITY	"	6,000	"
STANFORD UNIVERSITY	"	2,000	"
U S NAVAL ACADEMY	"	1,000	"
UNIVERSITY OF IDAHO	"	21,000	"
UNIVERSITY OF PENNSYLVANIA	"	1,000	"
UNIVERSITY OF SOUTHERN CALIFOR	"	1,000	"
TOTAL SCHOLARSHIP PROGRAM		**72,000**	
BOISE STATE UNIVERSITY	426.112	3,445	"
BRIGHAM YOUNG UNIVERSITY	"	700	"
BRIGHAM YOUNG UNIVERSITY- IDAH	"	500	"
CARLETON COLLEGE	"	50	"
COLLEGE OF IDAHO	"	3,300	"
DUKE UNIVERSITY	"	300	"
IDAHO STATE UNIVERSITY	"	2,175	"
MONTANA STATE UNIVERISTY FOUND	"	300	"
NORTHWEST NAZARENE UNIVERSITY	"	3,000	"
TRUSTEES OF THE UNIVERSITY OF	"	300	"
U S NAVAL ACADEMY FOUNDATION	"	100	"
UNIVERSITY OF IDAHO FOUNDATION	"	11,425	"
UNIVERSITY OF SOUTHERN CALIFOR	"	100	"
UNIVERSITY OF TEXAS AT AUSTIN	"	78	"
WASHINGTON STATE UNIVERSITY FO	"	100	"
TOTAL MATCH HIGHER EDUCATION		**25,873**	
BOISE VALLEY ECONOMIC PARTNERS	426.121	6,000	"
CALDWELL ECONOMIC DEVELOPMENT	"	3,215	"
CHAMBER OF COMMERCE	"	2,500	"
FAIRFIELD, CITY OF	"	-	"
GREAT RIFT BUSINESS DEVELOPMEN	"	4,000	"
JEROME, CITY OF	"	575	"
KUNA, CITY OF	"	3,550	"
LEMHI COUNTY ECONOMIC DEVELOPM	"	3,000	"
MEETING SYSTEMS INC	"	575	"
SNAKE RIVER ECONOMIC DEVELOPME	"	1,610	"
SUSTAIN BLAINE INC	"	4,800	"
WESTERN ALLIANCE FOR ECONOMIC	"	575	"
TOTAL ECONOMIC RECOVERY		**30,400**	

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Description	Account Number	Total Amount	Amount Assigned to Oregon
2000 FORD F550 36' VERSALIFT S	426.130	$ 16	None
2006 FORD F550 36' SERVICE BUC	"	47	"
ACTUAL INCENTIVE TAX	"	6	"
APRIL MATERIAL TRANSFER	"	8,000	"
BARNETT,OLEAN R	"	48	"
BECK,BRET E	"	149	"
BENEFITS FROM 232016	"	81	"
CORP INCENTIVE	"	33	"
CORP INCENTIVE FICA	"	3	"
GAUTHIER,MARC M	"	25	"
JOHNS,STEVEN A	"	348	"
JOHNSON,GREG L	"	28	"
JULY MISC TRANS	"	2,500	"
LUNCEFORD,GARTH D	"	25	"
MISC CORRECTIONS 2	"	75	"
ORTIZ,BERNABE	"	25	"
PAYROLL ACCR REVERSAL	"	(110)	"
PAYROLL ACCRUAL	"	163	"
PAYROLL TAX ACCRUAL	"	13	"
REVERSE CORP INCENT FICA	"	(5)	"
RUBBER TIEDOWN 21 IN	"	4	"
RUBBER TIEDOWN 31 IN	"	18	"
TOTAL NON CASH CONTRIBUTIONS		**11,490**	
TOTAL CONTRIBUTIONS ACCOUNT 426.1		$ 744,976	

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES
AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	ADM ASSOCIATES INC	Energy Efficiency Services	$ 5,488
2	ANDERSON BANDUCCI PLLC	Legal Services	5,872
3	AXON SOLUTIONS INC	Software Consultant Services	8,077
4	BANDUCCI WOODARD SCHWARTZMAN P	Legal Services	1,887
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	30,481
6	BERGLES LAW LLC	Legal Services	3,200
7	BETHKE LAW PLLC	Legal Services	736
8	BOARDVANTAGE, INC	Management Services	1,728
9	BROADRIDGE FINANCIAL SOLUTIONS	Management Services	2,177
10	BULLARD SMITH JERNSTEDT WILSON	Legal Services	1,528
11	CADMUS GROUP INC, THE	Management Services	2,284
12	CLEAREDGE PARTNERS INC	Management Services	3,304
13	CORPORATE OFFICE INSTALLATIONS	Office Equipment Services	10,259
14	D & R INTERNATIONAL, LTD	Environmental Services	4,803
15	DAVIS WRIGHT TREMAINE LLP	Legal Services	68,828
16	DELOITTE TAX LLP	Accounting Services	2,380
17	EMC CORPORATION	Environmental Services	2,379
18	EVERGREEN CONSULTING GROUP, LL	Management Services	7,888
19	EXPERIS IT SERVICES US, LLC	Computer Support Services	6,675
20	GARTNER GROUP	Management Services	6,781
21	GIVENS PURSLEY LLP	Legal Services	4,254
22	HARDESTY, REBECCA	Environmental Services	1,836
23	HONEYWELL INTERNATIONAL INC	Management Services	17,539
24	HYQUAL	Environmental Services	4,182
25	INDUSTRIAL HYGIENE RESOURCES,	Environmental Services	7,030
26	JACO ENVIRONMENTAL INC	Environmental Services	2,072
27	JOHNSON CONSULTING GROUP	Legal Services	1,553
28	JONES AND SWARTZ PLLC	Legal Services	1,468
29	MCDOWELL RACKNER & GIBSON PC	Legal Services	51,025
30	MCMILLEN ENGINEERING, LLC	Engineering Services	3,937
31	MILLER & CHEVALIER CHARTERED	Management Services	1,605
32	MIRANDE, MICHAEL	Legal Services	1,785
33	NIELSEN GROUP INC, THE	Consulting Services	8,769
34	OPINION DYNAMICS CORPORATION	Engineering Services	3,135
35	PAINE HAMBLEN LLP	Legal Services	5,862
36	PERKINS COIE LLP	Legal Services	15,861
37	REGENCE BLUESHIELD OF IDAHO	Management Services	14,704
38	RM ENERGY CONSULTING	Energy Efficiency Services	2,682
39	SCHWABE WILLIAMSON & WYATT	Legal Services	2,102
40	STEPTOE & JOHNSON LLP	Legal Services	10,419
41	STOEL RIVES LLP	Legal Services	4,258
42	SULLIVAN & CROMWELL	Legal Services	8,175
43	TEKSYSTEMS	Management Services	7,190
44	TETRA TECH INC	Environmental Services	6,316
45	THINK BIG SOLUTIONS INC	Management Services	2,268
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AND CHARGED TO OREGON OPERATING ACCOUNTS

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	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
47	TRC ENERGY SERVICES	Engineering Services	$ 2,434
48	TUERI LLC	Management Services	4,161
49	UNIVERSITY CORPORATION FOR	Cloud Seeding Modeling Services	10,798
50	UNIVERSITY OF ARIZONA	Weather Research & Forecast Services	1,643
51	UNIVERSITY OF IDAHO	Environmental Services	17,620
52	VAN NESS FELDMAN	Rate Case Services	12,543
53	WATERSHED SCIENCES INC	Environmental Services	2,174
54	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	1,750
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92	**TOTAL**		$ 419,906