THIS FILING IS	
Item 1: [X] 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 2012/Q4

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Deloitte.

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Suite 1700
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USA

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www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the accompanying financial statements of Idaho Power Company (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2012, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Idaho Power Company, as of December 31, 2012, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

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

Restricted Use

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

Deloitte & Touche LLP

February 21, 2013

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FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2012/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 Corporate Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	

08 Telephone of Contact Person, *Including Area Code* (208) 388-2761	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/15/2013

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Ken Petersen	03 Signature Ken Petersen	04 Date Signed *(Mo, Da, Yr)* 04/15/2013
02 Title Corporate Controller and 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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 Coporate Controller and CAO, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Idaho, June 30, 1989

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chief Executive Officer	J. LaMont Keen	675,000
3			
4	President & Chief Financial Officer	Darrel T. Anderson	420,000
5			
6	Executive Vice President, & Chief Operating Officer	Dan Minor	385,000
7			
8	Senior Vice President and General Counsel	Rex Blackburn	300,000
9			
10	Senior Vice President, Power Supply	Lisa Grow	260,000
11			
12	Senior Vice President, Finance & Treasurer	Steven Keen	260,000
13			
14	Vice President, Human Resources & Corporate Services	Luci McDonald	240,000
15			
16	Vice President and Chief Information Officer	Dennis Gribble	222,000
17			
18	Vice President, Customer Operations	Warren Kline	222,000
19			
20	Vice President, Public Affairs	Jeffrey Malmen	215,000
21			
22	Vice President, Chief Risk Officer	Lori Smith	215,000
23			
24	Vice President Delivery Engineering & Construction	Vern Porter	202,000
25			
26	Corporate Controller & Chief Accounting Officer	Ken Petersen	190,000
27			
28	Vice President, Regulatory Affairs	Gregory Said	172,500
29			
30	Corporate Secretary	Patrick Harrington	170,000
31			
32	Vice President, Supply Chain	Naomi Crafton-Shankel	170,000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
3		
4	Christine King	Standard Microsystems Corporation
5		80 Arkay Dr, Hauppauge, NY 11788
6		
7	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
8		
9	Stephen Allred	4642 W Dawson Dr Meridian, Id 83646
10		
11	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
12		
13	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	Richard G. Reiten (1)	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
17		Portland, Oregon 97204
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	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
24		
25	Richard Dahl ***	11659 Presilla Road, Santa Rosa Valley Ca, 93012
26		
27	Dennis L Johnson (2)	United Heritage Life Insurance
28		707 E United Heritage Ct Ste 130 Meridian Idaho 83642
29		
30	(1) Retired from Board of Directors 5/17/12.	
31		
32	(2) Approved 3/21/2013	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	FERC Docket No. ER06-787-002,003
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	201208275060	08/27/2012	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2012-2013 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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.

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1. None

2. None

3. None

4. None

5. New transmission line #728 Langley Gulch Power Plant to Willis Tap added 49.05 miles.
Changes to existing lines were:
Line #404 Rebuilt approx 30 wire miles added approx .85 miles new line.
Line #205 Deenergized transmisson line transferred to distribution 3.0 miles.
Line #529 New transmission line to distribution 3.0 miles.
Line #902-Line #433 Rerouted transmission to connect to new Justice station.
Line #328-Line #250 Connection to new Montour station .26 wire miles.

New Substations:
Montour switching station, Gem County, Idaho
Mountain Air Wind, Elmore County, Idaho
Langley Gulch Switchyard, Payette County, Idaho

New Power Plant:
Langely Gulch Power Plant, natural gas combined cycle power plant, Payette County, Idaho, in service 6/29/2012.

6. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022, and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042. The first mortgage bonds were issued under Idaho Power's shelf registration statement. As a result of these issuances, as of December 31, 2012, $150 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 sale of first mortgage bonds, medium-term notes to effect the early redemption in full of its $100 million of 4.75% first mortgage bonds, medium-term notes due November 2012.

7. None

8. Effective 1/11/12 a 3.0% general wage increase was implemented.

9. See pages 123.19 to 123.21

10. None

11. None

12. None

13. Idaho Power has added Dennis Johnson as a director effective 3/21/2013. The other change was the retirement of Richard Reiten all changes listed on page 105. There were however a couple of changes in the major security holders for 2012. The top ten institutional shareholders list saw 2 changes from 3rd quarter to 4th quarter.In the 4th quarter Thompson, Siegel & Walmsley LLC, and Schroder Investment Management Ltd. replaced American Century Investment Mgmt. and Dreman Value Management, LLC.

14. Idaho Power and its uunregulated 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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	4,922,872,974	4,473,847,185
3	Construction Work in Progress (107)	200-201	298,470,440	591,474,855
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,221,343,414	5,065,322,040
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,871,810,171	1,840,782,085
6	Net Utility Plant (Enter Total of line 4 less 5)		3,349,533,243	3,224,539,955
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)		3,349,533,243	3,224,539,955
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,462,166	2,081,420
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	84,680,243	78,529,519
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)		1,518	1,852
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		34,391,222	25,644,107
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		284,782	359,418
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		120,819,931	106,616,316
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,112,143	19,178,288
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		39,100	37,352
38	Temporary Cash Investments (136)		100,000	100,000
39	Notes Receivable (141)		72,492	94,776
40	Customer Accounts Receivable (142)		67,661,588	67,534,731
41	Other Accounts Receivable (143)		20,876,001	8,206,727
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,872,855	1,435,434
43	Notes Receivable from Associated Companies (145)		1,008,249	17,335,019
44	Accounts Receivable from Assoc. Companies (146)		63,847	0
45	Fuel Stock (151)	227	42,388,239	47,865,097
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	47,455,954	42,015,731
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	3,581,218	4,474,719
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)		12,688,220	12,273,571
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)		51,448,038	46,440,688
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		3,874,959	3,754,383
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		284,782	359,418
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)		266,212,411	267,516,230
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,143,425	16,992,504
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	1,141,110,726	989,194,015
73	Prelim. Survey and Investigation Charges (Electric) (183)		819,409	491,041
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		1,364,037	630,208
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	53,913,850	50,880,202
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)		14,921,058	13,613,712
82	Accumulated Deferred Income Taxes (190)	234	316,262,777	227,977,046
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,545,535,282	1,299,778,728
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,282,100,867	4,898,451,229

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	end of 2012/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	704,757,436
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	752,514,607	659,237,261
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	82,217,150	76,066,425
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)	-17,115,669	-11,622,052
16	Total Proprietary Capital (lines 2 through 15)		1,625,653,628	1,524,219,175
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,515,460,000	1,465,460,000
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	25,203,182	26,266,818
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,967,860	3,113,413
24	Total Long-Term Debt (lines 18 through 23)		1,537,695,322	1,488,613,405
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)		5,479,272	1,924,461
29	Accumulated Provision for Pensions and Benefits (228.3)		425,887,098	366,648,491
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,261,891	0
31	Accumulated Provision for Rate Refunds (229)		45,672,853	33,145,395
32	Long-Term Portion of Derivative Instrument Liabilities		0	107,763
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		22,982,049	21,366,767
35	Total Other Noncurrent Liabilities (lines 26 through 34)		502,283,163	423,192,877
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		108,223,362	97,996,387
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		252,507	1,511,606
41	Customer Deposits (235)		1,966,205	10,799,095
42	Taxes Accrued (236)	262-263	8,109,787	4,895,725
43	Interest Accrued (237)		22,441,369	22,038,081
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	end of 2012/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)		1,905,279	1,719,933
48	Miscellaneous Current and Accrued Liabilities (242)		30,534,183	33,498,725
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		1,054,644	4,706,863
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	107,763
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)		174,487,336	177,058,652
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		13,261,592	19,747,984
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,896,604	70,840,400
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	17,982,872	27,530,572
60	Other Regulatory Liabilities (254)	278	69,401,786	96,483,245
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)		1,080,279,413	933,326,224
64	Accum. Deferred Income Taxes-Other (283)		181,159,151	137,438,695
65	Total Deferred Credits (lines 56 through 64)		1,441,981,418	1,285,367,120
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,282,100,867	4,898,451,229

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	1,075,085,871	1,021,585,142		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	596,383,061	632,997,464		
5	Maintenance Expenses (402)	320-323	74,129,496	76,104,523		
6	Depreciation Expense (403)	336-337	116,113,891	113,001,742		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	317,075			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,483,540	6,764,513		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-13,255	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		39,784	28,099		
13	(Less) Regulatory Credits (407.4)		788,738			
14	Taxes Other Than Income Taxes (408.1)	262-263	30,488,808	28,894,715		
15	Income Taxes - Federal (409.1)	262-263	-14,482,226	-57,754,420		
16	- Other (409.1)	262-263	1,007,613	-803,160		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	239,208,729	116,679,418		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	200,111,787	99,841,847		
19	Investment Tax Credit Adj. - Net (411.4)	266	9,056,202	-1,131,934		
20	(Less) Gains from Disp. of Utility Plant (411.6)			-17,392		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		201,565	398,050		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		183,144			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		858,813,772	814,535,732		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		216,272,099	207,049,410		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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
1,075,085,871	1,021,585,142					2
						3
596,383,061	632,997,464					4
74,129,496	76,104,523					5
116,113,891	113,001,742					6
317,075						7
7,483,540	6,764,513					8
-13,255	-22,723					9
						10
						11
39,784	28,099					12
788,738						13
30,488,808	28,894,715					14
-14,482,226	-57,754,420					15
1,007,613	-803,160					16
239,208,729	116,679,418					17
200,111,787	99,841,847					18
9,056,202	-1,131,934					19
	-17,392					20
						21
201,565	398,050					22
						23
183,144						24
858,813,772	814,535,732					25
216,272,099	207,049,410					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)		216,272,099	207,049,410		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,639,354	1,142,767		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,634,620	974,498		
33	Revenues From Nonutility Operations (417)		46,890	51,602		
34	(Less) Expenses of Nonutility Operations (417.1)		276,349	-18,126		
35	Nonoperating Rental Income (418)		-16,185	-3,285		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,150,725	5,967,745		
37	Interest and Dividend Income (419)		2,018,711	2,178,296		
38	Allowance for Other Funds Used During Construction (419.1)		22,433,417	25,484,071		
39	Miscellaneous Nonoperating Income (421)		1,990,234	1,428,531		
40	Gain on Disposition of Property (421.1)			57,199		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		32,352,177	35,350,554		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		717,897	718,718		
46	Life Insurance (426.2)		-14,029	-757,078		
47	Penalties (426.3)		-560,608	430,042		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,256,347	1,167,810		
49	Other Deductions (426.5)		7,533,768	6,579,000		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,933,375	8,138,492		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	24,640	23,238		
53	Income Taxes-Federal (409.2)	262-263	-102,078	-638,707		
54	Income Taxes-Other (409.2)	262-263	-161,217	-112,459		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	652,958	511,882		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,320,966	1,327,221		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,906,663	-1,543,267		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		25,325,465	28,755,329		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		78,922,057	79,348,955		
63	Amort. of Debt Disc. and Expense (428)		1,570,010	1,653,291		
64	Amortization of Loss on Reaquired Debt (428.1)		1,008,756	911,000		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		3,858,107	2,474,590		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,929,405	13,332,724		
70	Net Interest Charges (Total of lines 62 thru 69)		73,429,525	71,055,112		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		168,168,039	164,749,627		
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)		168,168,039	164,749,627		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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		657,027,573	558,128,446
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)		162,017,314	158,781,882
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings on Hydro Projects under FPA	215.1	-1,193,716	(178,017)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-1,193,716	(178,017)
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			-68,739,968	(59,704,738)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-68,739,968	(59,704,738)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		749,111,203	657,027,573
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,403,404	2,209,688
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,403,404	2,209,688
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		752,514,607	659,237,261
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		76,066,425	70,098,680
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,150,725	5,967,745
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		82,217,150	76,066,425

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	168,168,039	164,749,627
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	116,113,891	113,001,742
5	Amortization of	[redacted]	11,025,871
6			
7			
8	Deferred Income Taxes (Net)	40,671,950	-58,819,227
9	Investment Tax Credit Adjustment (Net)	5,813,188	-726,590
10	Net (Increase) Decrease in Receivables	-1,457,986	-2,125,936
11	Net (Increase) Decrease in Inventory	930,136	-21,207,643
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	[redacted]	22,896,607
14	Net (Increase) Decrease in Other Regulatory Assets	-42,236,101	23,708,446
15	Net Increase (Decrease) in Other Regulatory Liabilities	-11,230,901	44,336,626
16	(Less) Allowance for Other Funds Used During Construction	22,433,417	25,484,072
17	(Less) Undistributed Earnings from Subsidiary Companies	6,150,724	5,967,745
18	Other (provide details in footnote):	[redacted]	27,407,253
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	241,526,208	292,794,959
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	[redacted]	-324,431,776
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	11,929,405	13,332,724
31	Other (provide details in footnote):	[redacted]	6,314,273
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-237,022,238	-331,450,227
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)	-7,000,000	
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	208,367
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):	[redacted]	-493,891
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-227,327,932	-331,735,751
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote): Capital Infusion from IDACORP	7,500,000	16,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	157,500,000	16,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-101,063,636	-121,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,959,067	-1,207,914
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-68,739,968	-59,704,738
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-16,262,671	-165,976,288
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,064,395	-204,917,080
87			
88	Cash and Cash Equivalents at Beginning of Period	19,315,638	224,232,718
89			
90	Cash and Cash Equivalents at End of period	17,251,243	19,315,638

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/15/2013	2012/Q4

FOOTNOTE DATA

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

Amortization	Twelve Months Ended 12/31/12
Plant	7,470,286
Regulatory assets	137,771
Regulatory liabilities	-
Unamortized debt expense	2,625,931
Unamortized discount	145,553
Water rights	1,042,009
Other	790,228
	12,211,778

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

Cash paid during the period for:	
Income taxes	(16,113,671)
Interest (net of amount capitalized)	70,447,471

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

Cash Flow from Operating Activities (Other)	Twelve Months Ended 12/31/12
Pension and postretirement benefit plan expense	45,230,196
Contributions to pension and postretirement benefit plans	(47,695,063)
Unbilled revenues	(5,007,351)
Customer deposits	(8,832,890)
Prepayments	(7,133,563)
Other	(8,152,211)
	(31,590,882)

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	26,881,874

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

Other Cash Flows from Plant	Twelve Months Ended 12/31/12
Sale of emission allowances and renewable energy certificates	2,738,701
	2,738,701

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

Other Investing Cash Flows	Twelve Months Ended 12/31/12
Disbursements from rabbi trust	673,287
Net change in notes receivable from subsidiary	16,326,770
Miscellaneous other investing activities	(328,035)
	16,672,022

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However 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 territory 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 and (6) non-utility revenues (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. 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 and for amounts that are expected to be refunded to customers. 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, 2012 and 2011. 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. Idaho Power's physical forward contracts 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. The objective of Idaho Power's risk management program is to mitigate the price risk associated with the purchase and sale of electricity and natural gas. 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 2.75 percent in 2012 and 2.83 percent in 2011.

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 2012 or 2011.

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 2012 and 2011 were 7.7 percent and 7.8 percent, respectively.

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 at the beginning and 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.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan. The following table presents Idaho Power's accumulated other comprehensive loss balance at December 31 (net of tax):

	2012	2011
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 4,136	$ 2,569
Senior Management Security Plan	(21,252)	(14,191)
Total	$ (17,116)	$ (11,622)

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:

	2012	2011
	(thousands of dollars)	
Federal income tax expense at 35% statutory rate	$ 70,320	$ 42,116
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,153)	(2,089)
AFUDC	(12,027)	(13,586)
Capitalized interest	5,075	6,465
Investment tax credits	(3,267)	(3,355)
Removal costs	(2,697)	(2,244)
Capitalized overhead costs	(8,750)	(5,950)
Capitalized repair costs	(19,250)	(14,000)
Tax method change - 263A	0	0
Tax method change - repairs	(7,845)	0
Uncertain tax positions - established	0	0
Uncertain tax positions - settled	0	(63,138)
State income taxes, net of federal benefit	7,646	1,846
Depreciation	14,398	14,100
Other, net	(8,703)	(4,583)
Total income tax (benefit) expense	$ 32,747	$ (44,418)
Effective tax rate	16.3%	(36.9%)

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

	2012	2011
	(thousands of dollars)	
Income taxes currently payable:		
Federal	$ (14,584)	$ 7,832
State	846	7,296
Total	(13,738)	15,128
Income taxes deferred:		
Federal	47,069	22,942
State	(9,640)	(6,920)
Total	37,429	16,022
Uncertain tax positions:		
Federal	0	(66,225)
State	0	(8,211)
Total	0	(74,436)
Investment tax credits:		
Deferred	12,323	2,223
Restored	(3,267)	(3,355)
Total	9,056	(1,132)
Total income tax (benefit) expense	$ 32,747	$ (44,418)

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

	2012	2011
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 55,085	$ 45,473
Advances for construction	3,010	5,118
Deferred compensation	23,463	22,067
Advanced payments	17,856	12,958
PCA	0	1,711
Tax credits	21,174	8,547
Net operating losses	47,351	0
Revenue sharing	2,796	10,594
Retirement benefits	146,546	122,445
Other	4,340	3,758
Total	321,621	232,671
Deferred tax liabilities:		
Property, plant and equipment	406,283	333,335
Regulatory assets	677,795	599,992
Conservation programs	5,114	3,464
PCA	16,832	0
Fixed cost adjustment	5,246	5,652
Retirement benefits	142,270	122,712
Other	13,257	10,304
Total	1,266,797	1,075,459
Net deferred tax liabilities	$ 945,176	$ 842,788

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):

	2012	2011
Balance at January 1,	$ —	$ 74,436
Additions for tax positions of the current year	—	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	(66,379)
Settlements with taxing authorities	—	(8,057)
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 in 2012 and a net reduction of $0.2 million in 2011. Accrued interest was zero as of December 31, 2012 and 2011. No penalties are accrued.

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 2012 for federal and 2009-2012 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 2012, the IRS completed its examination of IDACORP's 2011 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no material tax uncertainties for 2012 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

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.

In the third quarter of 2012 Idaho Power completed an income tax accounting method change for its 2011 tax year related to a portion of the capitalized repairs method. 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. A $7.8 million tax benefit was recognized in 2012 for the filed deduction related to the cumulative method change adjustment for years prior to 2011.

For the year ended December 31, 2012, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $21.5 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

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.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

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. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized the remaining $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2012, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $9.8 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

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 through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for 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):

Description	Remaining Amortization Period	Earning a Return(1)	Not Earning a Return	Total as of December 31, 2012	2011
Regulatory Assets:					
Income taxes		$ —	$ 677,795	$ 677,795	$ 603,772
Unfunded postretirement benefits(2)		—	308,850	308,850	262,503
Pension expense deferrals(3)		50,036	14,959	64,995	58,044
Energy efficiency program costs(3)		17,085	—	17,085	15,956
Power supply costs(3)	Varies	60,680	—	60,680	8,490
Fixed cost adjustment(3)	2013-2014	13,418	—	13,418	14,457
Asset retirement obligations(4)		—	15,411	15,411	15,557
Mark-to-market liabilities(5)		—	1,055	1,055	4,707
Other	2013-2021	1,202	2,547	3,749	3,861
Total		$ 142,421	$ 1,020,617	$ 1,163,038	$ 987,347
Regulatory Liabilities:					
Income taxes		$ —	$ 55,085	$ 55,085	$ 49,253
Investment tax credits		—	79,897	79,897	70,841
Deferred revenue-AFUDC (3)		29,404	16,269	45,673	33,145
Energy efficiency program costs(3)		4,130	—	4,130	—
Power supply costs (3)	Varies	17,778	—	17,778	13,121
Settlement agreement sharing mechanism(3)	2013-2014	7,151	—	7,151	27,099
Mark-to-market assets(5)		—	4,579	4,579	3,754
Other		2,439	256	2,695	1,409
Total		$ 60,902	$ 156,086	$ 216,988	$ 198,622

(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 and removal costs are discussed in Note 12.
(5) Mark-to-market assets and liabilities are discussed in Note 15.

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 significant 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, changes in contracted power purchase prices and volumes (including PURPA power purchases), and the levels of 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 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 exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during each of the years ended December 31, 2012 and 2011.

Effective Date	$ Change (millions)	Notes
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.
June 1, 2011	$ (40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.

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 each of the three years ended December 31, 2012 and 2011 are summarized in the table that follows.

Year and Mechanism	APCU or PCAM Adjustment
2012 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2012 APCU	A rate increase of $1.8 million annually took effect June 1, 2012.
2011 PCAM	Actual net power supply costs were below the deadband, which would have resulted in a $1.5 million deferral. However, Oregon-jurisdiction earnings were below the ROE threshold described above, resulting in no deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.

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 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, and on December 30, 2011 the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 2011 order provided for a 7.86 percent authorized 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 order nor the settlement stipulation specified an authorized rate of return on equity and did not impose a moratorium on Idaho Power's filing a general rate case at a future date.

In addition to a base rate increase, the settlement stipulation addressed Idaho Power's calculation of the load change adjustment rate (LCAR) to be applied in Idaho Power's PCA mechanism. The LCAR is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The LCAR adjusts power supply cost recovery within the Idaho-jurisdiction PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provided for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

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

- a specified distribution of the reduction in 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 equity in any calendar year from 2009 to 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 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

In April 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. In May 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

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 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 stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power extending, with modifications, some of the provisions of the January 2010 settlement agreement. The settlement stipulation 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 additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- 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 stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically 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. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the December 2011 settlement stipulation further 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 January 2010 and December 2011 Idaho Settlement Agreements: On May 31, 2012, the IPUC issued an order approving Idaho Power's request to share revenues under the January 2010 and December 2011 settlement agreements. Idaho Power recorded in 2011 a $27.1 million reduction to revenue for amounts to be refunded to customers and a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers (reducing Idaho customers' future obligation). The refund is being applied to the PCA rates in effect from June 1, 2012 to May 31, 2013.

Idaho Power's 2012 Idaho ROE exceeded 10.5 percent, triggering the sharing mechanism of the December 2011 settlement stipulation. For 2012, Idaho Power recorded a $7.2 million provision against current revenues, to be refunded to customers through a future rate reduction, and an additional $14.6 million of pension expense, to benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future.

Fixed Cost Adjustment: The fixed cost adjustment (FCA) began as a pilot program for Idaho Power's Idaho residential and small general service customers, with a term from 2007 through 2009. The 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. In April 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011, and in March 2012 the IPUC issued an order approving the FCA as a permanent program. The order also maintained the existing cap on the FCA of no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The IPUC noted in its order, however, that the FCA does not isolate or identify changes in cost recovery associated solely with Idaho Power's energy efficiency programs, and instead responds to all changes in load, and directed Idaho Power to file with the IPUC a proposal to adjust the FCA. On September 28, 2012, Idaho Power submitted a compliance filing and motion to the IPUC requesting that the IPUC approve the FCA methodology used during the pilot program, without change, or an alternative methodology proposed by Idaho Power. On January 31, 2013, the IPUC issued an order stating that the FCA will continue unchanged, but that the IPUC will continue to monitor the FCA results annually.

On May 8, 2012, the IPUC issued an order authorizing Idaho Power to increase its annual FCA collection to $10.3 million for the period from June 1, 2012 to May 31, 2013. The following table summarizes FCA rate adjustments since inception:

FCA Year	Period rates in effect	Annual Amount (in millions)
2011	June 1, 2012-May 31, 2013	$ 10.3
2010	June 1, 2011-May 31, 2012	$ 9.3
2009	June 1, 2010-May 31, 2011	$ 6.3

As of December 31, 2012, Idaho Power had a $13.4 million regulatory asset associated with the FCA.

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 power plant, which became commercially available on June 29, 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. Inclusion of the Langley Gulch power plant in Idaho Power's power supply portfolio also resulted in a change in Idaho Power's power supply cost assumptions. Accordingly, in the Langley Gulch order the IPUC also updated Idaho Power's LCAR to $17.64 per MWh, effective July 1, 2012.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2012, Idaho Power's deferral balance associated with the Idaho-jurisdiction was $62.9 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. Idaho Power has made substantial contributions to its defined benefit pension plan in recent years. The single largest contribution occurred in September 2010, when Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount. The amount contributed over the minimum required contribution was intended to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated 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. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan and during 2012 contributed $44.3 million.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

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, $14.5 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.

On March 15, 2012, Idaho Power filed an application with the IPUC requesting an order designating Idaho Power's 2011 demand-side management expenditures of $42.6 million as prudently incurred. On October 22, 2012 and December 11, 2012, the IPUC issued orders approving as prudently incurred $42.5 million of demand-side management expenditures, and deferring a portion of Idaho Power's additional requested amount for further review. Of Idaho Power's 2011 demand-side management expenditures, approximately $36 million were funded through a rider mechanism on customer bills and approximately $7 million were recorded as a regulatory asset. As of December 31, 2012, the Idaho energy efficiency rider balance was a regulatory liability of $4.1 million. Idaho Power's previous application filed in March 2011, which was approved by the IPUC in August 2011, designated Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses.

On October 31, 2012, Idaho Power filed an application with the IPUC requesting authorization to begin amortization and collection of the 2011 portion of the regulatory asset associated with its custom efficiency program (a demand-side resources program) over a four-year period, equal to approximately $2.9 million per year, including a carrying charge. A decision of the IPUC is pending.

The December 2011 IPUC general rate case settlement order also 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.

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, 2012, Idaho Power's net book value in the Boardman plant was $23.1 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. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdiction base rates. On May 31, 2012, the IPUC issued an order approving a settlement stipulation agreed to by Idaho Power, the IPUC Staff, and a large industrial customer of Idaho Power, which provided 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 resolved all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The OPUC approved the settlement stipulation on February 23, 2012, which 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. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger plant.

Cost Recovery for Langley Gulch Power Plant: On March 9, 2012, Idaho Power filed an application with the OPUC requesting an annual increase in Oregon jurisdiction revenues of $3.0 million for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base. 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.

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

Applicable Period	OATT Rate (per kW-year)
October 1, 2012 to September 30, 2013	$ 21.32
October 1, 2011 to September 30, 2012	$ 19.79
October 1, 2010 to September 30, 2011	$ 19.60

Idaho Power's most recent OATT filing was based on a net annual transmission revenue requirement of $108.4 million.

4. LONG-TERM DEBT

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

	2012	2011
First mortgage bonds:		
4.75% Series due 2012	$ —	$ 100,000
4.25% Series due 2013	70,000	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	—
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	—
Total first mortgage bonds	1,345,000	1,295,000
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	5,318	6,382
Unamortized premium/discount - net	(2,967)	(3,113)
Total Idaho Power outstanding debt(2)	1,537,696	1,488,614
Current maturities of long-term debt	(71,064)	(101,064)
Total long-term debt	$ 1,466,632	$ 1,387,550

(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, 2012 to $1.511 billion.

(2) At December 31, 2012 and 2011, the overall effective cost of Idaho Power's outstanding debt was 5.44 percent and 5.43 percent, respectively.

At December 31, 2012, the maturities for the aggregate amount of long-term debt outstanding were as follows (in thousands of dollars):

2013	2014	2015	2016	2017	Thereafter
$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,064	$ 1,465,343

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten 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. In August 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, medium-term notes, Series I maturing in August 2020, and $100 million of 4.85% first mortgage bonds, medium-term notes, Series I maturing in August 2040. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022, and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042. The first mortgage bonds were issued under Idaho

Power's shelf registration statement. As a result of these issuances, as of December 31, 2012, $150 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 sale of first mortgage bonds, medium-term notes to effect the early redemption in full of its $100 million of 4.75% first mortgage bonds, medium-term notes due November 2012.

Mortgage: As of December 31, 2012, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) 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 Mortgage.

The Mortgage 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. The lien of the indenture 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 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 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 Mortgage 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 Mortgage 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 Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage 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 $300 million credit facility which 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, 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 agreement. Under the facility, Idaho Power pays a facility fee on the commitment based on Idaho Power's credit rating for senior unsecured long-term debt securities. While the credit facility provides for an original maturity date of October 26, 2016, the credit agreement grants Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On October 12, 2012, Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity date under the agreement to October 26, 2017.

At December 31, 2012, no amounts were outstanding under Idaho Power's facility. At December 31, 2012, Idaho Power had regulatory authority to incur up to $450 million 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:

	2012	2011
Commercial paper balances:		
At the end of year	$ —	$ —
Average during the year	$ 3,578	$ —
Weighted-average interest rate		
At the end of the year	—%	—%

6. COMMON STOCK

Idaho Power Common Stock

In 2012 and 2011, IDACORP contributed $7.5 million and $16 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

Restrictions on Dividends

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. 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. At December 31, 2012, the leverage ratio for Idaho Power was 49 percent. Based on these restrictions, Idaho Power's dividends were limited to $794 million at December 31, 2012. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to Idaho Power from any material subsidiary. At December 31, 2012, Idaho Power was in compliance with all facility covenants.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states 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, 2012, Idaho Power's common equity capital was 51 percent of its total adjusted capital. Further, Idaho Power must obtain the approval of the OPUC before it may directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation also 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 shares of 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 accounts" is undefined in the Federal Power Act but could be interpreted to limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

In accordance with Section 10(d) of the Federal Power Act, Idaho Power has $3.4 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, 2012, the maximum number of shares available under the LTICP and RSP were 1,371,305 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. 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 performance awards are based on two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The 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 these awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The 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 these 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.

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2012	337,183	$ 26.40
Shares granted	120,549	37.56
Shares forfeited	(2,098)	35.59
Shares vested	(138,923)	22.42
Nonvested shares at December 31, 2012	316,711	$ 32.32

The total fair value of shares vested during the years ended December 31, 2012 and 2011 was $4.8 million and $4.1 million, respectively. At December 31, 2012, Idaho Power had $4.7 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.71 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2012, a total of 14,820 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $40.48 per share. Directors elected to defer receipt of 7,410 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, 2012, all compensation costs have been recognized. Idaho Power uses IDACORP's original issue and/or treasury shares to satisfy exercised options.

Idaho Power's stock option transactions are summarized below. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
Idaho Power				
Outstanding at December 31, 2011	9,456	$ 33.67	1.58	$ 83
Exercised	(1,500)	28.45		
Expired	(4,000)	39.50		
Outstanding at December 31, 2012	3,956	$ 29.75	2.05	$ 54
Vested and exercisable at December 31, 2012	3,956	$ 29.75	2.05	$ 54

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

	2012	2011
Fair value of options vested	$ —	$ —
Intrinsic value of options exercised	36	535
Cash received from exercises	77	3,838
Tax benefits realized from exercises	14	209

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):

	2012	2011
Compensation cost	$ 4,577	$ 4,082
Income tax benefit	1,789	1,596

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2012, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2013	2014	2015	2016	2017	Thereafter
Cogeneration and power production	$ 170,939	$ 182,123	$ 187,151	$ 189,880	$ 188,734	$ 2,938,582
Power and transmission rights	6,408	5,035	4,320	3,992	2,840	4,743
Fuel	73,627	63,236	56,942	9,418	9,317	94,849

As of December 31, 2012, Idaho Power had 779 MW nameplate capacity of PURPA-related projects on-line, with an additional 52 MW nameplate capacity of projects projected to be on-line by the end of 2014. The power purchase contracts for these projects have terms ranging from one to 35 years. During 2012, Idaho Power purchased 1,961,208 megawatt-hours (MWh) from these projects at a cost of $118 million, resulting in a blended price of $59.98 per MWh. Idaho Power purchased 1,495,108 MWh at a cost of $90 million in 2011.

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):

	2013	2014	2015	2016	2017	Thereafter
Operating leases	$ 1,888	$ 2,116	$ 2,123	$ 1,243	$ 955	$ 15,741
Equipment, maintenance, and service agreements	35,233	9,483	5,464	4,277	4,484	21,176
FERC and other industry-related fees	13,789	11,066	11,066	7,472	7,472	37,361

Idaho Power's expense for operating leases was approximately $6.0 million in 2012 and $5.2 million in 2011.

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 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, 2012, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on 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, thereof, 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. As available information changes, the matters for which Idaho Power is able to estimate the loss may change, and the estimates themselves may change. 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 IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending petitions 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 characterized these ripple claims as "speculative." However, the FERC refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve a settlement that provided for waivers of all claims in those proceedings, despite only limited objections from two market participants. Idaho Power and IESCo have petitioned for review of the FERC's decision. Based on its evaluation of the merits of such claims and the inability to estimate any potential exposure should the claims ultimately have merit, Idaho Power and IESCo have no remaining amount accrued for financial statement purposes relating to the western energy 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 also continues its active participation in the SRBA in seeking 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 Idaho Power 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 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 determine 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. Through its parent company IDACORP, Idaho Power also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power's pension plans include a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power's funding policy for its 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 2012 and 2011 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	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation at January 1	$ 655,439	$ 569,934	$ 65,043	$ 59,126
Service cost	25,571	20,478	2,151	1,950
Interest cost	31,489	30,322	3,218	3,094
Actuarial loss	77,328	55,535	13,335	4,251
Benefits paid	(22,135)	(20,830)	(3,232)	(3,378)
Benefit obligation at December 31	767,692	655,439	80,515	65,043
Change in plan assets:				
Fair value at January 1	390,081	397,003	—	—
Actual return on plan assets	48,616	(4,592)	—	—
Employer contributions	44,300	18,500	—	—
Benefits paid	(22,135)	(20,830)	—	—
Fair value at December 31	460,862	390,081	—	—
Funded status at end of year	$ (306,830)	$ (265,358)	$ (80,515)	$ (65,043)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,651)	$ (3,496)
Noncurrent liabilities	(306,830)	(265,358)	(76,864)	(61,547)
Net amount recognized	$ (306,830)	$ (265,358)	$ (80,515)	$ (65,043)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 291,966	$ 245,632	$ 33,605	$ 21,799
Prior service cost	989	1,335	1,289	1,502
Subtotal	292,955	246,967	34,894	23,301
Less amount recorded as regulatory asset	(292,955)	(246,967)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,894	$ 23,301
Accumulated benefit obligation	$ 640,330	$ 549,503	$ 72,288	$ 59,836

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. These investments totaled approximately $50.4 million and $41.2 million at December 31, 2012 and 2011, respectively, and are reflected in Investments and Company-owned life insurance on the consolidated balance sheets.

The table that follows 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	
	2012	2011	2012	2011
Service cost	$ 25,571	$ 20,478	$ 2,151	$ 1,950
Interest cost	31,489	30,322	3,218	3,094
Expected return on assets	(31,737)	(32,322)	—	—
Amortization of net loss	14,114	8,673	1,530	1,293
Amortization of prior service cost	347	519	212	242
Net periodic pension cost	39,784	27,670	7,111	6,579
Adjustments due to the effects of regulation(1)	(5,860)	6,662	—	—
Net periodic benefit cost recognized for financial reporting	$ 33,924	$ 34,332	$ 7,111	$ 6,579

(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 $14.6 million and $20.3 million in 2012 and 2011, respectively.

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

	Pension Plan		SMSP	
	2012	2011	2012	2011
Actuarial loss during the year	$ (60,448)	$ (92,449)	$ (13,335)	$ (4,251)
Reclassification adjustments for:				
Amortization of net loss	14,114	8,673	1,530	1,293
Amortization of prior service cost	347	519	212	242
Adjustment for deferred tax effects	17,979	32,193	4,532	1,062
Adjustment due to the effects of regulation	28,008	51,064	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ (7,061)	$ (1,654)

In 2013, Idaho Power expects to recognize as components of net periodic benefit cost $20.4 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2012, relating to the pension plan and SMSP. This amount consists of $17.0 million of amortization of net loss and $0.4 million of amortization of prior service cost for the pension plan, and $2.8 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):

	2013	2014	2015	2016	2017	2018-2022
Pension Plan	$ 23,882	$ 25,591	$ 27,490	$ 29,729	$ 32,179	$ 199,630
SMSP	3,721	3,948	4,130	4,129	4,326	23,932

As of December 31, 2012, Idaho Power's minimum required contributions to the pension plan is estimated to be zero in 2013. Idaho Power may elect to make discretionary contributions above the minimum funding requirements or at times earlier than the required dates.

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 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):

	2012	2011
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 66,669	$ 68,048
Service cost	1,292	1,323
Interest cost	3,135	3,434
Actuarial loss (gain)	3,180	(2,850)
Benefits paid(1)	(1,729)	(2,968)
Plan amendments	—	(318)
Benefit obligation at December 31	72,547	66,669
Change in plan assets:		
Fair value of plan assets at January 1	31,901	33,176
Actual return on plan assets	3,346	1,065
Employer contributions(1)	(131)	628
Benefits paid(1)	(1,729)	(2,968)
Fair value of plan assets at December 31	33,387	31,901
Funded status at end of year (included in noncurrent liabilities)	$ (39,160)	$ (34,768)

(1) Contributions and benefits paid are each net of $3,268 and $3,405 of plan participant contributions, and $430 and $444 of Medicare Part D subsidy receipts for 2012 and 2011, respectively.

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

	2012	2011
Net loss	$ 15,796	$ 14,112
Prior service cost (credit)	99	(323)
Transition obligation	—	2,040
Subtotal	15,895	15,829
Less amount recognized in regulatory assets	(15,895)	(15,536)
Less amount included in deferred tax assets	—	(293)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2012	2011
Service cost	$ 1,292	$ 1,323
Interest cost	3,135	3,434
Expected return on plan assets	(2,234)	(2,641)
Amortization of net loss	384	577
Amortization of prior service cost	(422)	(421)
Amortization of unrecognized transition obligation	2,040	2,040
Net periodic postretirement benefit cost	$ 4,195	$ 4,312

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

	2012	2011
Actuarial (loss) gain during the year	$ (2,068)	$ 1,274
Prior service cost arising during the year	—	318
Reclassification adjustments for:		
Amortization of net loss	384	577
Amortization of prior service cost	(422)	(421)
Amortization of unrecognized transition obligation	2,040	2,040
Adjustment for deferred tax effects	(153)	(1,659)
Adjustment due to the effects of regulation	219	(2,129)
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2013, Idaho Power expects to recognize as components of net periodic benefit cost $0.6 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2012, relating to the postretirement benefit plan. This amount consists of $0.7 million of amortization of net loss and $(0.1) 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):

	2013	2014	2015	2016	2017	2018-2022
Expected benefit payments	$ 4,010	$ 4,180	$ 4,320	$ 4,430	$ 4,530	$ 23,420
Expected Medicare Part D subsidy receipts	480	520	560	620	670	4,360

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	
	2012	2011	2012	2011	2012	2011
Discount rate	4.20%	4.90%	4.15%	5.10%	4.20%	5.05%
Rate of compensation increase(1)	4.35%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.5%	7.0%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2012	12/31/2011	12/31/2012	12/31/2011	12/31/2012	12/31/2011

(1) The 2012 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% 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 Benefit	
	2012	2011	2012	2011	2012	2011
Discount rate	4.90%	5.40%	5.10 %	5.40%	5.05 %	5.40 %
Expected long-term rate of return on assets	7.75%	8.25%	—	—	7.25 %	8.25 %
Rate of compensation increase	4.35%	4.50%	4.50 %	4.50%	—	—
Medical trend rate	—	—	—	—	6.5 %	7.0 %
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 6.5 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2012 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 343	$ (255)
Effect on accumulated postretirement benefit obligation	3,482	(2,708)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2012 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation December 31, 2012
Debt securities	24%	24%
Equity securities	54%	55%
Real estate	6%	6%
Other plan assets	16%	15%
Total	100%	100%

Assets are rebalanced as necessary to keep the portfolio close to target allocations.

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

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

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

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

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the 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, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

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

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 15. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2012				
Pension 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 assets(1)	$ 325	$ 33,062	$ —	$ 33,387

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

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2011				
Pension assets:				
Cash and cash equivalents	$ 6,141	$ —	$ —	$ 6,141
Short-term bonds	—	23,443	—	23,443
Long-term bonds	—	74,658	—	74,658
Equity Securities: Large-Cap	51,780	—	—	51,780
Equity Securities: Mid-Cap	17,961	14,002	—	31,963
Equity Securities: Small-Cap	31,825	—	—	31,825
Equity Securities: Micro-Cap	16,087	—	—	16,087
Equity Securities: International	30,444	32,118	—	62,562
Equity Securities: Emerging Markets	1,745	15,112	—	16,857
Real estate	—	—	25,119	25,119
Private market investments	—	—	27,786	27,786
Commodities funds	2,929	18,931	—	21,860
Total pension assets	$ 158,912	$ 178,264	$ 52,905	$ 390,081
Postretirement assets(1)	$ —	$ 31,901	$ —	$ 31,901

(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, 2011	$ 29,932	$ 22,069	$ 52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	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

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 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.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2012 and 2011.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and which covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $7 million and $6 million, and $5 million in 2012 and 2011, respectively.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on Idaho Power's consolidated balance sheet at December 31, 2012 and 2011 is $2.6 million and $3.8 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 2012 and 2011 (in thousands of dollars):

	2012		2011	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 2,217,334	2.36%	$ 1,832,287	2.22%
Transmission	931,403	2.02%	871,784	2.06%
Distribution	1,411,740	2.89%	1,434,925	3.12%
General and Other	355,295	6.47%	327,877	7.32%
Total in service	4,915,772	2.75%	4,466,873	2.83%
Accumulated provision for depreciation	(1,871,810)		(1,840,782)	
In service - net	$ 3,043,962		$ 2,626,091	

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, 2012 (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	$ 542,894	$ 16,528	$ 280,875	33	771
Boardman	Boardman, OR	79,031	1,355	55,940	10	64
Valmy Units 1 and 2	Winnemucca, NV	353,541	10,163	198,190	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 $75 million and $65 million in 2012 and 2011, 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 in both 2012 and 2011.

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 present 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 biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2012, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $1.4 million in the recorded AROs. The primary cause of the increase in the AROs in 2012 is an increased ARO for the Valmy generating facility evaporation pond as determined by a revised evaporation pond decommissioning study.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric 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 costs recorded as regulatory liabilities on Idaho Power's Consolidated Balance Sheet as of December 31, 2012 and 2011.

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

	2012	2011
Balance at beginning of year	$ 21,367	$ 16,952
Accretion expense	984	936
Revisions in estimated cash flows	1,416	3,930
Liability settled	(785)	(451)
Balance at end of year	$ 22,982	$ 21,367

13. INVESTMENTS

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

	2012	2011
Available-for-sale equity securities	31,913	22,205
Executive deferred compensation plan investments	2,478	3,439
Total Idaho Power investments	34,391	25,644

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 by Idaho Power as of December 31, 2012 and December 31, 2011 (in thousands of dollars).

	December 31, 2012			December 31, 2011		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 6,792	$ —	$ 31,913	$ 4,220	$ 1	$ 22,205

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, 2012, there were no securities in an unrealized loss position. At December 31, 2011, one security was in an immaterial unrealized loss position. No other-than-temporary impairment was recognized for this security due to the limited severity and duration of the unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2012 or 2011.

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 also 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 objective of Idaho Power's energy purchase and sale activity is 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 commodity-related derivative instruments not meeting the normal purchases and normal sales exception to derivative accounting are recorded at fair value on the balance sheet. Because of Idaho Power's PCA mechanisms, unrealized gains and losses associated with the changes in fair value of these derivative instruments are recorded as regulatory assets or liabilities. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities, Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception.

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 related to derivative instruments executed with the same counterparty under the same master netting agreement.

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 at December 31, 2012 and 2011 (in thousands of dollars).

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
December 31, 2012				
Current:				
Financial swaps	Other current assets	$ 5,122	Other current assets	$ 978
Financial swaps	Other current liabilities	320	Other current liabilities	1,372
Forward contracts	Other current assets	155	Other current assets	4
Forward contracts			Other current liabilities	2
Long-term:				
Financial swaps	Other assets	96		
Forward contracts	Other assets	189		
Total		$ 5,882		$ 2,356
December 31, 2011				
Current:				
Financial swaps	Other current assets	$ 4,361	Other current assets	$ 1,036
Financial swaps	Other current liabilities	1,526	Other current liabilities	4,755
Forward contracts	Other current assets	70	Other current liabilities	1,370
Long-term:				
Financial swaps	Other assets	359	Other liabilities	108
Total		$ 6,316		$ 7,269

The table below presents the gains and losses on derivatives not designated as hedging instruments for the year ended December 31, 2012 and 2011 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income(1)	
		2012	2011
Financial swaps	Off-system sales	$ 15,104	$ 9,594
Financial swaps	Purchased power	(6,280)	(7,124)
Financial swaps	Fuel expense	(6,359)	501
Financial swaps	Other operations and maintenance	(302)	425
Forward contracts	Fuel expense	(1,755)	—

(1) Excludes changes in fair value of 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 both financial and physical 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.

Idaho Power had volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2012 and 2011 set forth in the table below.

Commodity	Units	December 31, 2012	December 31, 2011
Electricity purchases	MWh	404,990	225,600
Electricity sales	MWh	1,373,525	1,298,420
Natural gas purchases	MMBtu	13,476,660	7,928,311
Natural gas sales	MMBtu	3,932,889	352,129
Diesel purchases	Gallons	833,921	1,273,997

Credit Risk

At December 31, 2012, Idaho Power did not have material credit 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 under Western Systems Power Pool agreements, physical gas contracts are under North American Energy Standards Board contracts, and financial transactions are under International Swaps and Derivatives Association, Inc. contracts. These contracts all 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, 2012, was $2.4 million. Idaho Power posted no collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, Idaho Power would have been required to post $5.9 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:
  - 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 derivatives are contracts entered into as part of its management of loads and resources. Electricity swaps are valued on the Intercontinental Exchange with quoted prices in an active market. Natural gas and diesel derivative valuations are performed using New York Mercantile Exchange (NYMEX) pricing, adjusted for location basis, which are also quoted under NYMEX. 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 information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2012 and 2011 (in thousands of dollars). Idaho Power's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels for the years presented.

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivatives	$ 2,201	$ 1,674	$ —	$ 3,875	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	2,478	—	—	2,478	3,439	—	—	3,439
Available-for-sale securities: Equity securities	31,913	—	—	31,913	22,205	—	—	22,205
Liabilities:								
Derivatives	$ —	$ 1,055	$ —	$ 1,055	$ 405	$ 4,302	$ —	$ 4,707

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, 2012 and 2011, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. 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 is based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

	December 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Liabilities:				
Long-term debt (1)	$ 1,537,696	$ 1,819,213	$ 1,491,727	$ 1,737,912

(1) Long-term debt is categorized as Level 2 within the fair value hierarchy, as defined earlier in this Note 15.

16. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.8 million in both 2011 to 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 both 2012 and 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	2,969,301			(12,536,816)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				934,902
3	Preceding Quarter/Year to Date Changes in Fair Value	(400,010)			(2,589,429)
4	Total (lines 2 and 3)	(400,010)			(1,654,527)
5	Balance of Account 219 at End of Preceding Quarter/Year	2,569,291			(14,191,343)
6	Balance of Account 219 at Beginning of Current Year	2,569,291			(14,191,343)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,060,888
8	Current Quarter/Year to Date Changes in Fair Value	1,567,262			(8,121,767)
9	Total (lines 7 and 8)	1,567,262			(7,060,879)
10	Balance of Account 219 at End of Current Quarter/Year	4,136,553			(21,252,222)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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			(9,567,515)		
2			934,902		
3			(2,989,439)		
4			(2,054,537)	164,749,627	162,695,090
5			(11,622,052)		
6			(11,622,052)		
7			1,060,888		
8			(6,554,505)		
9			(5,493,617)	168,168,039	162,674,422
10			(17,115,669)		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	4,915,771,669	4,915,771,669
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,915,771,669	4,915,771,669
9	Leased to Others		
10	Held for Future Use	7,101,305	7,101,305
11	Construction Work in Progress	298,470,440	298,470,440
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,221,343,414	5,221,343,414
14	Accum Prov for Depr, Amort, & Depl	1,871,810,171	1,871,810,171
15	Net Utility Plant (13 less 14)	3,349,533,243	3,349,533,243
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,848,861,113	1,848,861,113
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,949,058	22,949,058
22	Total In Service (18 thru 21)	1,871,810,171	1,871,810,171
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)	1,871,810,171	1,871,810,171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	23,171,392	5,821,094
4	(303) Miscellaneous Intangible Plant	34,317,102	3,996,149
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	57,494,197	9,817,243
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,707,109	
9	(311) Structures and Improvements	143,758,647	4,462,234
10	(312) Boiler Plant Equipment	569,484,225	6,942,778
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	150,650,806	1,837,467
13	(315) Accessory Electric Equipment	60,126,130	8,217,762
14	(316) Misc. Power Plant Equipment	15,180,475	1,700,368
15	(317) Asset Retirement Costs for Steam Production	8,005,226	2,208,288
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	948,912,618	25,368,897
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	30,132,870	709,417
28	(331) Structures and Improvements	156,227,013	1,306,025
29	(332) Reservoirs, Dams, and Waterways	252,890,100	288,688
30	(333) Water Wheels, Turbines, and Generators	197,920,861	3,082,590
31	(334) Accessory Electric Equipment	45,854,367	1,142,182
32	(335) Misc. Power PLant Equipment	19,081,434	1,372,330
33	(336) Roads, Railroads, and Bridges	8,112,491	5,122
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	710,219,136	7,906,354
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	7,169,595	125,884,758
39	(342) Fuel Holders, Products, and Accessories	4,445,866	3,542,032
40	(343) Prime Movers	98,951,696	127,879,002
41	(344) Generators	31,681,900	41,765,594
42	(345) Accessory Electric Equipment	25,077,582	70,480,766
43	(346) Misc. Power Plant Equipment	3,138,437	2,600,177
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	173,155,082	372,152,329
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,832,286,836	405,427,580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
60,000			28,932,486		3
7,062,241			31,251,010		4
7,122,241			60,189,199		5
					6
					7
			1,707,109		8
510,858			147,710,023		9
13,077,075			563,349,928		10
					11
4,716,265			147,772,008		12
144,087			68,199,805		13
1,163,072			15,717,771		14
			10,213,514		15
19,611,357			954,670,158		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			30,842,287		27
15,258			157,517,780		28
34,486			253,144,302		29
159,917			200,843,534		30
349,138			46,647,411		31
162,205			20,291,559		32
			8,117,613		33
					34
721,004			717,404,486		35
					36
			2,690,006		37
28,341			133,026,012		38
			7,987,898		39
20,000			226,810,698		40
			73,447,494		41
			95,558,348		42
			5,738,614		43
					44
48,341			545,259,070		45
20,380,702			2,217,333,714		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	35,130,605	445,557
49	(352) Structures and Improvements	57,994,797	12,150,635
50	(353) Station Equipment	351,924,749	14,049,079
51	(354) Towers and Fixtures	147,491,416	7,679,305
52	(355) Poles and Fixtures	107,026,913	13,764,963
53	(356) Overhead Conductors and Devices	171,801,963	13,274,942
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	413,346	-23,080
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	871,783,789	61,341,401
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,423,471	-648,228
61	(361) Structures and Improvements	32,336,183	-956,431
62	(362) Station Equipment	194,190,240	-3,641,870
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	228,880,444	2,946,117
65	(365) Overhead Conductors and Devices	122,536,891	3,105,791
66	(366) Underground Conduit	47,989,345	-1,002,615
67	(367) Underground Conductors and Devices	196,700,971	1,730,268
68	(368) Line Transformers	429,419,556	26,406,882
69	(369) Services	57,225,209	-73,102
70	(370) Meters	112,429,849	570,493
71	(371) Installations on Customer Premises	2,754,620	166,375
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,394,855	130,714
74	(374) Asset Retirement Costs for Distribution Plant	643,639	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,434,925,273	28,734,394
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	16,128,658	-8,453
87	(390) Structures and Improvements	84,984,787	8,918,686
88	(391) Office Furniture and Equipment	40,558,356	10,610,178
89	(392) Transportation Equipment	60,978,129	5,524,778
90	(393) Stores Equipment	1,600,036	285,525
91	(394) Tools, Shop and Garage Equipment	6,054,996	515,974
92	(395) Laboratory Equipment	11,866,322	643,136
93	(396) Power Operated Equipment	10,696,486	833,783
94	(397) Communication Equipment	32,714,344	7,877,762
95	(398) Miscellaneous Equipment	5,255,018	401,277
96	SUBTOTAL (Enter Total of lines 86 thru 95)	270,837,132	35,602,646
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)	270,837,132	35,602,646
100	TOTAL (Accounts 101 and 106)	4,467,327,227	540,923,264
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)	4,467,327,227	540,923,264

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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
			35,576,162		48
8,541			70,136,891		49
529,861		-89,005	365,354,962		50
74,995			155,095,726		51
435,295			120,356,581		52
584,891			184,492,014		53
					54
					55
			390,266		56
					57
1,633,583		-89,005	931,402,602		58
					59
			4,775,243		60
25,585			31,354,167		61
945,164		61,696	189,664,902		62
					63
1,470,555			230,356,006		64
1,630,230			124,012,452		65
152,847			46,833,883		66
699,100			197,732,139		67
4,614,794			451,211,644		68
298,753			56,853,354		69
42,067,815			70,932,527		70
55,841			2,865,154		71
					72
20,358			4,505,211		73
			643,639		74
51,981,042		61,696	1,411,740,321		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			16,120,205		86
250,021			93,653,452		87
8,373,808			42,794,726		88
1,612,476			64,890,431		89
7,739			1,877,822		90
105,260			6,465,710		91
254,363			12,255,095		92
34,346			11,495,923		93
689,228		27,309	39,930,187		94
34,013			5,622,282		95
11,361,254		27,309	295,105,833		96
					97
					98
11,361,254		27,309	295,105,833		99
92,478,822			4,915,771,669		100
					101
					102
					103
92,478,822			4,915,771,669		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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			112,703
4	Transmission Stations			429,822
5	Transmission Lines			195,517
6	Distribution Stations			1,078,591
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			72,016
25	Homedale Substation	2/29/08		215,719
26	Beacon Light Substation	12/30/02		555,940
27				
28				
29				
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43				
44				
45				
46				
47	Total			7,101,305

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	61,547,907
2	ROLLUP RELIC COST HELLS CANYON	42,037,561
3	BOARDMAN - HEMINGWAY 500 KV LI	26,705,806
4	GATEWAY WEST 500KV LINE	20,908,755
5	ROLLUP RELIC COST OXBOW	19,419,114
6	HELLS CANYON RELICENSING OUTSI	15,674,400
7	NIAGARA SPRINGS HATCHERY EXPAN	9,194,254
8	BRIDGER 2008C123LP U1 TURBINE	8,911,069
9	WQ - ONGOING HELLS CANYON RELI	6,829,646
10	CIAC LIABILITY RECLASS	6,046,206
11	BUILD NEW JUSTICE TRANSMISSION	5,082,098
12	RIVER ENG.-HELLS CANYON CONTIN	4,693,433
13	BOBN REPLACE C233 AND C234 SER	4,297,924
14	BRIDGER UNDISTRIBUTED WORK ORD	3,646,399
15	B2H PERMITTING 11/1/2011 & FOR	3,139,305
16	VALMY UNDISTRIBUTED WORK ORDER	2,357,929
17	B2H TLINE CONSTRUCTION COSTS	1,935,953
18	LEGAL DEPT. LABOR FOR RELICENS	1,852,244
19	VALMY 98250588 DUST COLLECTOR	1,851,747
20	REL-HCC OREGON REAUTHORIZATION	1,741,966
21	BCW - UG FIBER INSTALLATION	1,718,795
22	VALMY 98301759 V1 UTILITY MACT	1,695,010
23	SGIG - INTEGRATIONS	1,554,085
24	SGIG - OUTAGE MANAGEMENT SYSTE	1,411,182
25	2012 PC PURCHASES - CUSTOMER O	1,319,812
26	IPCO/ / 2011 DOWNTOWN CAPITAL	1,316,681
27	KPRT1002: EVAL SYNCHRONOUS CON	1,201,239
28	OBPR LOCAL SERVICE UPGRADE	1,147,272
29	SGIG CUSTOMER DATA MART	1,081,974
30	OTHER MINOR PROJECTS UNDER $1,000,000	38,150,674
31		
32		
33		
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41		
42		
43	TOTAL	298,470,440

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	1,818,635,521	1,818,635,521		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	116,113,891	116,113,891		
4	(403.1) Depreciation Expense for Asset Retirement Costs	317,075	317,075		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,189,325	3,189,325		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	100,439	100,439		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	119,720,730	119,720,730		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	85,356,581	85,356,581		
13	Cost of Removal	7,686,282	7,686,282		
14	Salvage (Credit)	2,327,547	2,327,547		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	90,715,316	90,715,316		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	CIAC, Reserve adj and Asset Retireme	1,220,178	1,220,178		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,848,861,113	1,848,861,113		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	529,534,301	529,534,301		
21	Nuclear Production				
22	Hydraulic Production-Conventional	366,042,954	366,042,954		
23	Hydraulic Production-Pumped Storage				
24	Other Production	41,316,874	41,316,874		
25	Transmission	285,425,520	285,425,520		
26	Distribution	516,534,664	516,534,664		
27	Regional Transmission and Market Operation				
28	General	110,006,800	110,006,800		
29	TOTAL (Enter Total of lines 20 thru 28)	1,848,861,113	1,848,861,113		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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			76,066,425
5				
6	Subtotal Idaho Energy Resources Company			78,529,519
7				
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41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	78,529,519

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
6,150,725		82,217,149		4
				5
6,150,725		84,680,243		6
				7
				8
				9
				10
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6,150,725		84,680,243		42

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	47,865,097	42,388,239	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)	14,808,824	15,899,274	
8	Transmission Plant (Estimated)	12,917,846	12,836,658	
9	Distribution Plant (Estimated)	13,087,873	17,335,350	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,201,188	1,384,672	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	42,015,731	47,455,954	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	4,474,719	3,581,218	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	94,355,547	93,425,411	

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	IPC TRANS SIS 74705988,74705990,				
3	74705993,7470995, 74706017		186623	8,661	186623
4	IPC TRANS SIS 76655746	2,514	186623	(2,514)	186623
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LAVA BEDS WIND PARK	1,324	186623	10,871	186623
23	HIDDEN HOLLOW EXPANSION GI#291		186623	(2,247)	186623
24	WHEATGRASS RIDGE WIND PROJECT 294	943	186623	78,847	186623
25	COTTEREL MTN WIND PROJECT 302	101	186623	73,413	186623
26	ADAMS COUNTY BIOMASS GI#304		186623	26,652	186623
27	SWAGER FARMS GI#307	3,823	186623	12,427	186623
28	DOUBLE B DAIRY GI#308	179	186623	6,517	186623
29	GRAND VIEW SOLAR GI#312	657	186623	13,711	186623
30	YELLOWSTONE PWR GI#315		186623	18,586	186623
31	JACK RANCH WIND GI 322	5,847	186623	28,322	186623
32	SALMON CREEK GI 325	1,990	186623	31,366	186623
33	TUMBLE WEED 34.5 GI 332		186623	(6,006)	186623
34	HIGH MESA WIND GI 334	4,020	186623	89,366	186623
35	DYNAMIS LANDFILL GI 344	17,086	186623	1,235	186623
36	MURPHY FLAT WIND GI 346	385	186623	99,615	186623
37	NOTCH BUTTE GI 349	13,602	186623	(5,839)	186623
38	RAINBOW WEST GI 352	14,645	186623	16,557	186623
39	SALMON FALLS WIND GI 357		186623	98,158	186623
40	NOTCHBUTTE GI 359		186623	17,414	186623

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
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12					
13					
14					
15					
16					
17					
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19					
20					
21	**Generation Studies**				
22	COLEMAN HYDRO GI 362	266	186623	13,662	186623
23	GRAND VIEW SOLAR TWO GI 369	8,881	186623	(10,000)	186623
24	MEADOW CREEK WIND GI 370		186623	139,096	186623
25	MTNAIR EXPANSION GI 373-378		186623	28,899	186623
26	BANNOCK COUNTY LANDFILL GI 380	7,517	186623	1,253	186623
27	FARGO DROP GI 382	(4,348)	186623	7,023	186623
28	BETASEED BIOGAS GI 383		186623	(1,913)	186623
29	JETTCREEK WINDFARM GI 384	3,252	186623	(2,252)	186623
30	PROSPECTOR WINDFARM GI 385		186623	1,000	186623
31	BENSON CREEK WINDFARM GI 386		186623	1,000	186623
32	DURBIN CREEK WINDFARM GI 387		186623	1,000	186623
33	MIDPOINT SOLAR GI 388	6,861	186623	(6,861)	186623
34	AMALSUGAR PAUL GI 389	3,067	186623	(1,000)	186623
35	EAGLE VIEW DAIRY GI 390	11,487	186623	(17,686)	186623
36	GRANDVIEW SOLAR 3 GI 394	2,616	186623	(16,000)	186623
37	GRANDVIEW SOLAR 4 GI 395	13,268	186623	(16,000)	186623
38	MURPHY FLAT WIND FARM	7,112	186623	(20,000)	186623
39	BLACK CANYON BLISS HYDRO		186623	(500)	186623
40	BENSON CREEK WINDFARM GI 401		186623	(51,000)	186623

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
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19					
20					
21	**Generation Studies**				
22	DURBIN CREEK WINDFARM GI 402		186623	(1,000)	186623
23	JETT CREEK WINDFARM GI 403		186623	(1,000)	186623
24	PROSPECTOR WINDFARM GI 404		186623	(1,000)	186623
25	WILLOW CREEK WINDFARM GI 405		186623	(1,000)	186623
26	SHOSHONE FALLS GI 136	47,511	186623		186623
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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)	15,557,422	475,084	1823/230	2,448,633	13,583,873
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	ASC 815 Mark to Market - ST (182330)	4,599,099	15,345,805	244	18,890,261	1,054,643
5						
6	ASC 815 Mark to Market - LT (182333)	107,763	754,454	244	862,217	
7						
8	Regulatory Unfunded (182322)	603,772,178	74,023,292			677,795,470
9	Accum Deferred Income Noncurrent					
10						
11	PCA Deferral Idaho - IPUC Order #27660		129,900,586	Various	77,551,097	52,349,489
12	(Amort period 06/12 thru 05/13) (182323)					
13						
14	PCA Prior Year Deferral Idaho - IPUC Order #27660		117,190,627	Various	137,659,759	-20,469,132
15	(Amort period 06/11 thru 05/12) (182324)					
16						
17	Fixed Cost Adjusment (FCA) (182302)	10,273,296	15,154,508	1823	16,597,586	8,830,218
18	IPUC Order #30267 (amort period 06/12 thru 05/13)					
19						
20	Prior Year FCA IPUC Order #30267 (182309)	4,183,172	34,887,291	1823/400	34,483,059	4,587,404
21						
22	FERC Grid West Expense (182304)	111,728		401	83,796	27,932
23	ER08-629-000 (amort period 05/08 thru 04/13)					
24						
25	AOCI Impact of Unfunded Post Retirement Liability	15,536,177	2,440,534	228	2,081,396	15,895,315
26	IPUC Order #30256 (182306)					
27						
28	Oregon Pension Expense Capitalized	1,345,487	609,906	401/4073	51,008	1,904,385
29	OPUC Order #10-064 (182339)					
30	(Avg amort 35yrs for each yr capitalized expense)					
31						
32	Deferred Pension Expense Net of Contributions	17,140,322	38,341,161	Various	42,641,622	12,839,861
33	IPUC Order #30333 (182321)					
34						
35	AOCI Impact of Unfunded Pension Liability	246,966,765	60,448,165	228	14,460,369	292,954,561
36	IPUC Order #30256 (182320)					
37						
38	ID DSM Rider Reclass IPUC Order #29026 (182301)	5,321,997	2,803,416	254	8,125,413	
39						
40	PCAM Oregon 2008 (182346)	6,454,985	522,415			6,977,400
41	OPUC Order #08-238					
42						
43	PCAM Interest Reserve 2008 (182329)	(429,062)		4210	171,220	-600,282

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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	OPUC Order #08-238					
2						
3	Excess Power Cost Deferral 2007 (182358)	4,762,316	2,178,235	254	4,537,039	2,403,512
4	IPUC Order #09-189					
5						
6	2007 EPC Interest Reserve (182351)	(308,869)	149,208			-159,661
7	IPUC Order #09-189					
8						
9	Oregon DSM Rider Reclass (182359)	3,537,442	11,370,116	254	14,907,558	
10	OPUC Advice #05-03					
11						
12	2009 Reorg IPUC Order #330914 (182318)	691,967		401	230,656	461,311
13	(amort period 01/10 thru 12/14)					
14						
15	OATT Revenue Deferred Reserve (182336)	2,064,469		400	401,425	1,663,044
16	IPUC Order #30940 (amort period 01/11 thru 12/13)					
17						
18	Idaho Pension Cash (182327)	38,976,484	48,631,908	401/4210	37,572,305	50,036,087
19	IPUC Order #32248 (amort period 06/11 thru 05/14)					
20						
21	FERC Pension Cash (182328)	582,156	70,000	401	437,695	214,461
22	IPUC Order #32248 (amort period 06/11 thru 05/14)					
23						
24	Excess Power Cost Unbilled Amort (186356)	(142,646)	1,888,291	401	1,883,067	-137,422
25						
26	Cus Efficiency Incentive IPUC Order #32245 (182317)	7,230,724	6,889,623	254	34,146	14,086,201
27						
28	Cus Efficiency Incen Res IPUC Order #32245 (182314)	(134,282)	291,455	1823/4210	1,073,638	-916,465
29						
30	Lidar Surveys IPUC Order #32426 (182361)	436,047		402	43,605	392,442
31	(amort period 01/12 thru 12/21)					
32						
33	Bennett Mtn Maintenance IPUC Order #32426	299,546		402	74,886	224,660
34	(amort period 01/12 thru 12/15) (182379)					
35						
36	PCA Unbilled Amortization (182316)		27,899,136	254/401	25,207,858	2,691,278
37						
38	Idaho Boardlman ARO Order #32549 (182393)		1,476,390	4031/4110	100,337	1,376,053
39						
40	Langley Revenue Accrual Order #12-226 (182398)		814,665	4074	7,271	807,394
41						
42	[redacted]	257,332	1,926,126	Various	1,946,764	236,694
43						
44	**TOTAL :**	989,194,015	596,482,397		444,565,686	1,141,110,726

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Schedule Page: 232.1 Line No.: 42 Column: a

Accounts included in minor items:
182305
182331
182334
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182355
182362
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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)	715,957	113,600	401	91,362	738,195
2	Rents/Easements Long Term					
3						
4	Advance Prepaid (186709)	1,367,261		143/151	33,315	1,333,946
5	Coal Royalties					
6						
7	Security plan (186720)	19,001,732	881,380	165/4262	1,386,445	18,496,667
8	Net Insurance Asset					
9						
10	American Falls Bond Ref(186722)	191,604		401	14,552	177,052
11	(Amort 04/00 - 02/25)					
12						
13	Prepaid Credit Facility(186025)	992,670	1,445,227	431	1,475,836	962,061
14	(amort period 10/12 thru 10/17)					
15						
16	Company Owned (186726)	5,058,356	1,982,401	Various	2,891,345	4,149,412
17	Life Insurance					
18						
19	American Falls Water Rights	13,632,948		401	1,042,009	12,590,939
20	(amort 01/06 - 02/25) (186727)					
21						
22	Milner Bond Guarantee (186734)	6,381,818		253	1,063,636	5,318,182
23	(Amort 02/07 - 2/17)					
24						
25	American Falls - Bond refinance	631,989		401	47,999	583,990
26	(Amort through 02/25)(186770)					
27						
28	Transmission Deposit(186784)	710,578	6,987	131	717,565	
29						
30	Prepaid Exp (186052)	650,472	1,163,703	401	665,987	1,148,188
31	Contract I.T. Long Term					
32						
33	Long Term (186121)	1,268,456		228	53,791	1,214,665
34	Workers Compensation					
35						
36	Power Plant- Valmy (186793)	136,406	683,486	107	803,397	16,495
37						
38	Power Plant- Boardman (186794)	104,813	61,020	107/401	164,234	1,599
39						
40	Transmission & Generation		6,651,247	Various	5,429,021	1,222,226
41	Studies (186623)					
42						
43	Prepaid Coal LT (186797)		5,958,328			5,958,328
44						
45	[redacted]	35,142	8,175,376	Various	8,208,613	1,905
46						
47	Misc. Work in Progress		[redacted]			
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	50,880,202	[redacted]			53,913,850

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Accounts included in minor items:
186100
186304
186731
186946

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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)	[redacted]	109,509,600
6			
7	Other (See footnote)	[redacted]	185,672,424
8	TOTAL Electric (Enter Total of lines 2 thru 7)	208,895,006	295,182,024
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	[redacted]	21,080,753
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	227,977,046	316,262,777

Notes

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

	Beginning Balance	Ending Balance
Federal NOL-Operating	-	45,964,500
AFUDC Hells Canyon Relicensing	12,958,192	17,855,802
Deferred Idaho ITC	5,539,827	13,747,559
Post Retiree Benefits-VEBA	7,474,519	9,221,017
Regulatory Asset-Non Current	-	4,458,718
Stock Based Compensation	2,777,081	3,148,063
Advances for Construction	5,117,985	3,009,900
Revenue Sharing	10,594,314	2,795,770
Rate Case Disallowance	2,621,256	2,505,417
Oregon-Pension Expense	1,504,842	1,897,934
Regulatory Liability-Current	-	1,722,247
Executive Deferred Compensation	1,344,427	968,904
Valmy Union Pacific Contract	-	884,286
Post Retirement Benefits	1,172,345	822,852
Oregon NOL-Operating	-	262,521
Non-VEBA Pension and Benefits	265,356	217,768
Montana NOL-Operating	-	78,812
Bridger Revenue Deferral	-	65,767
Deferred GBC	24,000	24,000
Prov For Rate Refunds-Bridger PC	-	8,895
Boardman Decommission	-	(151,131)
Total Other Electric	51,394,143	109,509,600

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

Pension	96,551,657	114,530,586
Regulatory Liability for Income Taxes	45,472,547	51,285,735
Minimum Pension Liability	9,109,442	13,641,829
Postretirement Plan	6,367,217	6,214,273
Total Other	157,500,863	185,672,424

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

Senior Management Security Plan	16,319,201	17,720,515
SMSP-Market Change of Rabbi Investments	1,626,015	1,626,015
Federal NOL-Non Operating	-	850,678
Micron-CIAC	1,050,482	812,600
Meridian Gold Contributions	86,342	64,230
Oregon NOL-Non Operating	-	5,037
Montana NOL-Non Operating	-	1,679
Total Non Electric	19,082,040	21,080,753

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
						8
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						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	
9		
10		
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39		
40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
2		
3		
4		
5		
6		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	2,096,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.25%Series due 2013	70,000,000	641,201
19			372,696 D
20			
21	4.75% Series due 2012	100,000,000	944,356
22			1,047,617 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	1,647,045,000	27,957,280

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	6,150,000	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	3,400,000	12
						13
						14
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	15
						16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12		1,781,250	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
				1,540,663,182	78,922,057	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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			
12	Humboldt Variable due 2024	49,800,000	1,697,856
13			
14	Sweetwater Variable due 2026	116,300,000	3,026,122
15			
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	1,615,460,000	27,957,280
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	1,647,045,000	27,957,280

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	37,232	10
						11
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	12
						13
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	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	2,311,250	19
						20
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	1,585,625	21
						22
				1,515,460,000	78,922,057	23
						24
						25
						26
						27
						28
						29
04/26/00	2/1/25			19,885,000		30
02/10/92				5,318,182		31
				25,203,182		32
				1,540,663,182	78,922,057	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	168,168,039
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	
30		
31		
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44		

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

4000-FEDERAL NOL	$ 133,757,649
4003-CONSTRUCTION ADV-252	(6,023,102)
4005-AVOIDED COST INT CAP	14,498,584
4006-RETIREMENTS-RECORD TAX GAIN/LOSS	4,000,000
4010-EMISSION ALLOWANCE-254.409-411	239,401
4013-CIAC TAXABLE INCOME-IN ACCT 107	(4,044,584)
4021-ENGINEERING FEES-TAXABLE-IN ACCT 107	185,124
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	4,914,112
4506-CIAC-MERIDIAN GOLD	(56,560)
4507-CIAC-MICRON-DRAM	(608,470)
Total	**$ 146,862,154**

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

Total Federal and State taxes deducted on books	$ 32,747,228
4011-RETIREMENTS-BOOK ACCTG REVERSED	324,912
4014-DARK FIBER CNTRCTS	(33,333)
5001-BAD DEBT EXPENSE	437,421
5010-SFAS 112-POST-EMPLY BEN 182/253	(893,956)
5014-OVERACCRUED VACATION-ACCT 242	(351,199)
5017-INJURIES & DAMAGES	808,602
5019-DIRECTORS FEES DEF	19,066
5022-CAPITALIZED OVERHEADS	(24,792,454)
5024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	600,000
5025-MILNER FALLING WATER - REV ACCRL	(238,941)
5027-AMORTIZATION OF ACCOUNT 114	441,194
5028-OREGON OPER PROPERTY TAX ADJ	(158,609)
5030-IPCO MIGRATION/SHAREOWNER RGHTS	(248,959)
5023-PENSION EXPENSE-Acct 228	21,839,939
5033-NONVEBA PEN&BEN-Acct 228	(121,725)
5035-PCA EXPENSE DEFERRAL	(47,922,795)
5043-AMERICAN FALLS - FALLING WATER CONTRACT-FT	219,181
5046-EXECUTIVE DEFERRED COMP-SHORT TERM	147,701
5047-EXECUTIVE DEFERRED COMP-LONG TERM	(1,108,242)
5052-AMORTIZATION OF ACCOUNT 181	310,738
5053-STOCK BASED COMPENSATION	838,659
5055-OPUC GRID WEST LOANS-ACCT 182	14,191
5056-FERC GRID WEST EXP-ACCT 182	83,796
5057-INTERVENER FUNDING ORDERS-ACCT 182	32,135
5058-FIXED COST ADJUSTMENT (FCA)-ACCT 182	1,038,846
5059-PS & I COSTS-ACCT 182	33,915
5060-OREGON-PCAM (POWER COST ADJ MECHANISM)	(1,689,298)
5061-PENSION EXPENSE-OREGON	1,824,384
5062-LIDAR SURVEYS DEFFERAL-ACCT 182	43,605
5063-BENNETT MTN MAINT DEFERRAL	74,886
5064-BRIDGER REVENUE DEFERRAL	168,224
5065-VALMY UNION PACIFIC CONTRACT	2,261,891
5066-BOARDMAN DECOMMISSION	(386,574)
5501-SEC PLAN-NET INSURANCE COSTS	(49,323)
5503-128-EDC-UNREALIZED GAIN/LOSS FROM RABBI TRUST	(843,602)
5504-NONDEDUCTIBLE POLITICAL EXP-426.4	942,261

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5505-SEC PLAN-BENEFIT ACCR		3,584,382
5510-FINES & PENALTIES-OPERATING		(560,511)
5531-RATE CASE DISALLOWANCES-REVERSE AMORT		(296,299)
5532-DELIVERY ACCRUALS-253.550		2,696
5536-VEBA INCOME TAXES		(1,537)
CM14-RECALSS ACQUISTION ADJ 114		(454,449)
Total	**$**	**(11,311,953)**

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

7009-PROV FOR RATE REFUND-BRIDGER POLLUTION CONTROL	$	(22,751)
7010-AFUDC HC RELICENSING-ACCT 229		(12,527,458)
7011-OATT REVENUE DEFICIENCY		(401,425)
7012-REVENUE SHARING ACCT 25-CURR		19,947,676
7013-LANGLEY REVENUE ACCRUAL		802,262
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		6,150,724
7502-ALLOWANCE FOR OFUDC		22,433,417
7503-ALLOWANCE FOR BFUDC		11,929,405
7509-SECURITY PLAN-INSURANCE PROCEEDS		236,376
Total	**$**	**48,548,226**

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8001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$	(4,437,438)
8009-DEPR-FEDERAL ADJ		182,781,618
8016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D		398,251
8020-CONSERVATION PROGRAMS		(8,949,040)
8027-NEVADA OPERATING PROPERTY TAX ADJ		(42,023)
8034-REMOVAL COSTS		7,706,171
8038-OREGON EXCESS PWR SUPPLY COSTS		(2,204,373)
8039-STATE TAX-NOT DEDUCTED ON PRIOR RETURN		168,884
8041-AM FALLS - UNAMORTIZED DEBT EXP		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT-FT		1,307,345
8057-REORGANIZATION COSTS		(230,656)
8072-INTANGIBLE ASSET-LABOR DEDUCT-IN ACCT 107		1,605,000
8073-REPAIRS DEDUCTION		55,000,000
8077-PP INS & OTR EXP (1 YR OR LESS)-165		64,321
8079-CUSTOM EFFICIENCY INCENTIVE PAY		6,073,295
8080-APPLY DOE FUNDS TO AMI CLOSED WO'S		11,716,783
8501-COLI-TAX ADJ FROM BOOKS		123,678
8504-OREGON NONOP PROPERTY TAX ADJUST		16
8703-IPCO - 162 (M) $1m THRESHOLD		(147,264)
8901-REGULATORY ASSET-CURRENT		11,404,830
8901-REGULATORY ASSET-NON CURRENT		(11,404,830)
8902-REGULATORY LIABILITY-CURRENT		(4,405,288)
8902-REGULATORY LIABILITY-NON CURRENT		4,405,288
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		4,283,445
Total	**$**	**255,170,014**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	-4,057,093		-14,584,809	-18,652,448	
3	Social Security - (FOAB)	1,188		13,701,846	13,703,041	
4	Unemployment			93,541	93,541	
5	Subtotal Federal	-4,055,905		-789,422	-4,855,866	
6						
7	State of Idaho:					
8	Property	8,416,100		20,904,095	19,869,999	
9	Non-Operating	10,914		23,078	22,457	
10	Income	-664,104		814,349	2,640,227	
11	KWH	180,678		1,909,280	1,996,097	[redacted]
12	Unemployment	1		681,157	681,157	
13	Regulatory Commission			2,042,319	2,042,319	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	7,943,589		26,374,428	27,252,406	-2,000
16						
17	State of Oregon					
18	Property		1,182,418	2,525,392	2,684,001	
19	Non-Operating Property		834	1,562	1,700	
20	Income	-110,793		-114,483	-99,661	
21	Regulatory Commission			162,571	162,571	
22	Unemployment			45,074	45,074	
23	Franchise	167,970		748,331	723,173	
24	Subtotal Oregon	57,177	1,183,252	3,368,447	3,516,858	
25						
26	State of Montana:					
27	Property	135,483		270,942	271,049	
28	Subtotal Montana	135,483		270,942	271,049	
29						
30	State of Nevada:					
31	Property		508,757	985,247	943,225	
32	Subtotal Nevada		508,757	985,247	943,225	
33						
34	State of Wyoming					
35	Corporate License			4,850	4,850	
36	Property	763,723		1,642,855	1,585,150	
37	Subtotal Wyoming	763,723		1,647,705	1,590,000	
38	Other States Income	51,658		-42,123	-1,789	
39	Payroll Tax Credit			-14,521,618		
40						
41	TOTAL	4,895,725	1,692,009	17,293,606	28,715,883	-2,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
10,546		-14,482,226			[redacted]	2
-8		13,701,846				3
		93,541				4
10,538		-686,839			-102,583	5
						6
						7
9,450,196		20,314,893			[redacted]	8
11,534	850				[redacted]	9
-2,489,982		1,150,954			[redacted]	10
91,860		1,909,280				11
1		681,157				12
		2,042,319				13
		150				14
7,063,609	850	26,098,753			275,675	15
						16
						17
	1,341,027	2,407,945			[redacted]	18
					[redacted]	19
-125,615		-104,242			[redacted]	20
		162,571				21
		45,074				22
193,128		748,331				23
67,513	1,341,027	3,259,679			108,768	24
						25
						26
135,376		270,367			[redacted]	27
135,376		270,367			575	28
						29
						30
	466,735	985,247				31
	466,735	985,247				32
						33
						34
		4,850				35
821,427		1,642,855				36
821,427		1,647,705				37
11,324		-39,099			[redacted]	38
		[redacted]				39
						40
8,109,787	1,808,612	17,014,195			279,411	41

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

```
Account 409.2      $  (102,078)
Account 234.2            (505)
                   ------------
Total              $  (102,583)
                   ===========
```

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

Account 107 $ 587,202

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

Account 408.2 $ 23,078

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

```
Account 409.2      $ (159,930)
Account 234.2        (176,675)
                   ----------
Total              $ (336,605)
                   ==========
```

Schedule Page: 262 Line No.: 11 Column: b

This balance is different from year end by $2,000. The $2,000 was for irrigation customer refunds. The refunds had a contra balance and were inadverently reclassed from account 236208 to 143900.

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

Account 107 $ 117,447

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

Account 408.2 $ 1,562

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

```
Account 409.2      $    (1,258)
Account 234.2           (8,983)
                   -----------
Total              $   (10,241)
                   ===========
```

Schedule Page: 262 Line No.: 27 Column: l

Account 131 $ 575

Schedule Page: 262 Line No.: 38 Column: l

```
Account 409.2      $      (29)
Account 234.2          (2,995)
                   ----------
Total              $   (3,024)
                   ==========
```

Schedule Page: 262 Line No.: 39 Column: i

This amount is an offset to lines 3, 4, 11 & 22. Each month employer paid payroll taxes flow into various 408.1 accounts. Also each month these amounts are offset with a different 408.1 account. These payroll taxes are then allocated back to balance sheet and o & m accounts based on labor.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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%	665,312				63,866	
4	7%						
5	10%	23,955,140				1,491,712	
6	11%	1,240,255				26,372	
7	Other - State	44,979,694	411.4	12,322,953	411.4	1,684,801	
8	TOTAL	70,840,401		12,322,953		3,266,751	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	44,979,695	411.4	12,322,953	411.4	1,684,801	
13							
14							
15							
16							
17							
18							
19							
20							
21							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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
601,446	10.42		3
			4
22,463,428	16.06		5
1,213,883	47.03		6
55,617,846	26.70		7
79,896,603			8
			9
			10
			11
55,617,847			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			23
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			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	12,764,219	107/401	294,038,860	285,919,580	4,644,939
2						
3	Point to Point Trans Study(253201)	876,153	232	500		875,653
4						
5	FTV (253202)	4,066,666	400	400,000		3,666,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Boardman To Hemingway (253220)		143/107	11,951,306	12,803,157	851,851
9						
10	Sho Ban Trans ROW (253480)	247,500	242	15,000		232,500
11	(Amort Period Jan 2005-Dec 2027)					
12						
13	Milner Falling Water (253953)	1,098,421	186/401	1,063,636	824,695	859,480
14	Amort Period (Feb 1992 - Feb 2017)					
15						
16	Postretirement Benefits (253960)	2,998,707	401	893,956		2,104,751
17						
18	Directors Deferred Compensation	4,638,308	131	505,560	524,626	4,657,374
19	(253980-253999)					
20						
21	IBM Mainframe Software Licenses	734,853	232	775,115	40,262	
22	(Amort period 2010-2015) (253950)					
23						
24	USAF Battery Replacement (253906)	105,706	107	137,263	31,575	18
25						
26	[redacted]	39	various	22	89,623	89,640
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	27,530,572		309,781,218	300,233,518	17,982,872

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

Accounts included in minor items:
253000
253042

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	[redacted]	82,177,337	9,229,112
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	333,334,634	82,177,337	9,229,112
6	Non-Operating Property			
7	Other - Regulatory Asset for I	599,991,590		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	933,326,224	82,177,337	9,229,112
10	Classification of TOTAL			
11	Federal Income Tax	795,963,655	81,445,627	9,160,530
12	State Income Tax	137,362,569	731,710	68,582
13	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	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
						406,282,859	2
							3
							4
						406,282,859	5
							6
		182	18,328	182	74,023,292	673,996,554	7
							8
			18,328		74,023,292	1,080,279,413	9
							10
			15,376		59,850,992	928,084,368	11
			2,952		14,172,300	152,195,045	12
							13

NOTES (Continued)

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

	2012	Changes during Year				Adjmts Dr		Adjmts Cr.		2012
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. Cr. g	Amt h	Acct. Dr. i	Amt j	Ending Balance k
Accelerated Depreciation	321,467,908	78,371,738	9,085,759							390,753,887
Intangible Asset-Labor Deduction	13,817,345	677,108								14,494,453
Taxable CIAC in CWIP Bal.	(2,146,044)	3,004,854								858,810
Valmy Capitalized Items	351,266		76,500							274,766
Misc Software Develop Costs	17,655	120,598								138,254
Engineering Fees in Acct 107	(173,496)	3,038	66,853							(237,311)
TOTAL	333,334,634	82,177,337	9,229,112	0	0		0		0	406,282,859

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	[redacted]		
2	Electric			
3	Other Electric -- See Note	[redacted]	111,408,529	87,144,355
4				
5				
6				
7				
8	Other -- See Note	[redacted]		
9	TOTAL Electric (Total of lines 3 thru 8)	136,997,166	111,408,529	87,144,355
10	Gas	[redacted]		
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	[redacted]		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	137,438,695	111,408,529	87,144,355
20	Classification of TOTAL	[redacted]		
21	Federal Income Tax	115,291,045	93,455,498	73,101,397
22	State Income Tax	22,147,650	17,953,031	14,042,958
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
							2
						56,986,228	3
							4
							5
							6
							7
					19,125,576	123,400,688	8
					19,125,576	180,386,916	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
330,706						772,235	18
330,706					19,125,576	181,159,151	19
[redacted]							20
277,414					16,043,587	151,966,147	21
53,292					3,081,989	29,193,004	22
							23

NOTES (Continued)

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

		Changes during Year				Adj Dr.		Adj Cr.		
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. Cr. g	Amt h	Acct. Dr. i	Amt j	Ending Balance k
Pension	20,087,171	18,054,956	16,616,850							21,525,276
PCA Expense Deferral	(5,129,482)	41,004,777	22,359,515							13,515,780
Conservation Programs	6,237,951	2,602,188	3,726,460							5,113,679
Fixed Cost Adjustment	5,651,756	4,483,220	4,889,356							5,245,619
Regulatory Asset-Current	0	10,756,134	6,297,416							4,458,718
Oregon PCAM	1,742,549	1,800,157	1,049,571							2,493,134
Regulatory Liability-Non Current	0	17,529,102	15,806,854							1,722,247
Oregon Excess Power Costs	1,685,308	13,139,849	14,001,648							823,508
OATT Revenue Deficiency	807,104		156,937							650,167
Renewable Engy Certif -rec sales	859,641	1,698,868	1,921,172							637,337
Langley Revenue Accrual	0	313,644								313,644
Reorganization Costs	270,524	0	90,175							180,350
LIDAR Surveys Deferral	170,473		17,047							153,425
Bennett Mtn Maintenance Deferral	117,108		29,277							87,831
Intervenor Funding Orders	68,803	16,805	29,369							56,239
OPUC Grid West Loans	17,568		5,548							12,020
FERC Grid West Expense	43,680		32,760							10,920
Emission Allowance	95,142	1,584	93,594							3,132
PS & I Costs-Coal & CHP Plts-Write Off	14,233		13,259							974
Bonus Deferral	(11,653)	3,134								(8,518)
Delivery accruals	(5,822)	4,111	7,545							(9,255)
TOTAL	32,722,054	111,408,529	87,144,355	0	0		0		0	56,986,228

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

		Changes during Year				Adj Dr.		Adj Cr.		
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. Cr. g	Amt h	Acct. Dr. i	Amt j	Ending Balance k
Pension	96,551,657							190	17,978,929	114,530,586
Postretirement Plan	6,073,869							190	140,405	6,214,273
Unrealized gains on Mkt Securities	1,649,586							219	1,006,242	2,655,828
TOTAL	104,275,112	0	0	0	0		0		19,125,576	123,400,687

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

		Changes during Year				Adj Dr.		Adj Cr.		
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. Cr. g	Amt h	Acct. Dr. i	Amt j	Ending Balance k
Unrealized Gain/Loss From Rabbi Trust	139,718			329,806						469,524
Advance Coal Royalties	301,486			893						302,379
Oregon Non-Op Prop Tax Adj	326			7						332
TOTAL	441,529	0	0	330,706	0		0		0	772,235

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Market to Market Short Term - (254001)	3,394,965	175	13,988,797	14,888,370	4,294,538
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	359,418	175	1,263,773	1,189,137	284,782
5	IPUC Order # 28661					
6						
7	OER 32368-323697 - (254007)				581,743	581,743
8	Order # 32368					
9						
10	Unfunded Accum Def Income Tax (254966)	45,472,547	various	530,982	6,344,170	51,285,735
11						
12	Idaho DSM Rider (254201)		various	34,245,702	38,286,324	4,040,622
13	Order #29026					
14						
15	Oregon DSM Rider - (254202)		various	16,626,489	12,711,554	-3,914,935
16	Advise #05-03					
17						
18	Oregon Solar Pilot - (254005)	766,096	various	233,363	659,888	1,192,621
19	Order #10-198					
20						
21	Oregon Reclass (254204)	4,110,320	1823	5,580,001	1,469,681	
22						
23	Green Tags Oregon (254415)	279,605	various	286,696	161,484	154,393
24	Order #11-086					
25						
26	Power Cost Adjustment-Current (254423)	10,578,946	1823	63,448,231	52,869,285	
27						
28	Regulatory Unfunded Accum Def Income Tax (254419)	3,780,588	1823	60,778	79,106	3,798,916
29						
30	Revenue Sharing (254101)	27,098,897	various	27,200,636	7,252,960	7,151,221
31	IPUC Order #32558					
32						
33	BPA Credit Residential Idaho (254401)	411,557	various	1,534,209	1,672,522	549,870
34	Advice # 11-03 (ID) #11-15 (OR)					
35						
36	WAQC Carryover (254901)	159,309	various	159,309	87,634	87,634
37	IPUC Order #29505					
38						
39						
40						
41	TOTAL	96,483,245		166,095,646	139,014,187	69,401,786

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Idaho Boardman Decommissing - (254393)		143/400	444,146	152,957	-291,189
2	IPUC Order #32549					
3						
4	Oregon Boardman Decommissing - (254394)		143/400	144,780	49,395	-95,385
5	OPUC Order #12235					
6						
7	Bridger Depreciation #12-296 -(254800)				168,224	168,224
8						
9						
10	[redacted]	70,997	various	347,754	389,753	112,996
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	96,483,245		166,095,646	139,014,187	69,401,786

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Schedule Page: 278.1 Line No.: 10 Column: a

Accounts included in minor items:
254004
254006
254008
254402
254402
254403
254404
254411
254412

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	431,555,478	405,981,556
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	375,354,223	322,307,065
5	Large (or Ind.) (See Instr. 4)	145,054,266	140,701,371
6	(444) Public Street and Highway Lighting	3,588,495	3,289,385
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	955,552,462	872,279,377
11	(447) Sales for Resale	61,534,224	101,602,140
12	TOTAL Sales of Electricity	1,017,086,686	973,881,517
13	(Less) (449.1) Provision for Rate Refunds	17,809,784	37,734,709
14	TOTAL Revenues Net of Prov. for Refunds	999,276,902	936,146,808
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	[redacted]	3,564,200
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,226,450	24,256,300
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	[redacted]	38,244,930
22	(456.1) Revenues from Transmission of Electricity of Others	21,054,698	19,372,904
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	75,808,969	85,438,334
27	TOTAL Electric Operating Revenues	1,075,085,871	1,021,585,142

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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
5,039,358	5,146,013	413,610	409,786	2
				3
5,881,587	5,458,954	82,485	82,045	4
3,132,573	3,099,743	118	123	5
31,798	29,720	2,069	1,578	6
				7
				8
				9
14,085,316	13,734,430	498,282	493,532	10
2,183,262	3,634,924			11
16,268,578	17,369,354	498,282	493,532	12
				13
16,268,578	17,369,354	498,282	493,532	14

Line 12, column (b) includes $ 4,136,172 of unbilled revenues.

Line 12, column (d) includes -18,962 MWH relating to unbilled revenues

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

This consists of :

Service Establishment/Connection Charges (Includes late and after hour charges)	2,836,590
Field Collections Charges	350,900
Misc. Under $250,000	457,528
	3,645,018

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

This consists of :

DSM Activity	27,299,917
Stand-by-Service	306,070
Misc. items under $250,000	276,816
	27,882,803

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	5,036,448	421,030,853	412,920	12,197	0.0836
3	03 - Residential Master Meter	4,493	354,253	23	195,348	0.0788
4	04 - Residential - EW		-15			
5	05 - Residential - TOD	8,553	710,075	667	12,823	0.0830
6	15 - Dusk to dawn lighting	2,807	618,102			0.2202
7	Unbilled Revenues	-12,992	1,986,871			-0.1529
8	Other Revenues		6,855,335			
9	Total 440	[redacted]	[redacted]	413,610	12,184	0.0856
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	158,687	16,695,877	30,745	5,161	0.1052
13	09P - General service	455,960	23,295,097	194	2,350,309	0.0511
14	09S - General service	3,202,887	192,136,834	31,743	100,901	0.0600
15	09T - General service	5,025	273,445	3	1,675,000	0.0544
16	15 - Dusk to Dawn Light	4,092	678,277			0.1658
17	19P - Uniform rate contracts	2,157,337	96,558,875	110	19,612,155	0.0448
18	19S - Uniform rate contracts	6,493	325,376	1	6,493,000	0.0501
19	19T - Uniform rate contracts	107,954	5,260,412	4	26,988,500	0.0487
20	24 - Irrigation Pumping	2,048,435	134,326,911	18,955	108,068	0.0656
21	40 - General service	11,188	804,135	845	13,240	0.0719
22	Special Contracts	862,444	39,505,500	4	215,611,000	0.0458
23	Commercial & Industrial Unbill	-6,293	2,111,315			-0.3355
24	Other Revenues		8,436,439			
25	Total 442	[redacted]	[redacted]	82,604	109,126	0.0577
26						
27	444 - Public Street Lighting:					
28	40 - General service	1,167	83,845	444	2,628	0.0718
29	41 - Street lighting	27,477	3,257,727	1,208	22,746	0.1186
30	42 - Traffic control lighting	2,831	141,880	417	6,789	0.0501
31	Unbilled	323	37,986			0.1176
32	Other Revenues		67,057			
33	Total 444	31,798	3,588,495	2,069	15,369	0.1129
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,104,278	951,416,290	498,283	28,306	0.0675
42	Total Unbilled Rev.(See Instr. 6)	-18,962	4,136,172	0	0	-0.2181
43	TOTAL	14,085,316	955,552,462	498,283	28,268	0.0678

Schedule Page: 304 Line No.: 9 Column: b

This amount is different from page 301 column D line 2 in the amount of 48 MWh due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 9 Column: c

This amount is different from page 301 column B line 2 in the amount of $4 due to an error during the year where a rate 07 was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 25 Column: b

This amount is different from page 301 column D total of line 4 and 5 in the amount of 48 MWh due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 25 Column: c

This amount is different from page 301 column B total of line 4 and 5 in the amount of $4 due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Raft River Rural Electric					
2						
3	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
4	Arizona Public Service Co.	[redacted]	WSPP	n/a	n/a	n/a
5	Avista Corp.	SF	WSPP	n/a	n/a	n/a
6	Avista Corp.	[redacted]	WSPP	n/a	n/a	n/a
7	Barclays Bank PLC	[redacted]	-	n/a	n/a	n/a
8	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
9	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
10	Bonneville Power Administration	[redacted]	WSPP	n/a	n/a	n/a
11	BP Energy Company	SF	WSPP	n/a	n/a	n/a
12	Brookfield Energy Marketing LP	SF	WSPP	n/a	n/a	n/a
13	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
14	Cargill Power Markets LLC	[redacted]	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
					2
107,575		2,122,843		2,122,843	3
1,593		3,530		3,530	4
32,746		654,534		654,534	5
550		6,875		6,875	6
		1,775,255		1,775,255	7
2,105		41,615		41,615	8
109,259		2,527,790		2,527,790	9
450		3,150		3,150	10
2,492		1,329		1,329	11
400		6,000		6,000	12
201		1,696		1,696	13
			535,817	535,817	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Cargill Power Markets LLC	[redacted]	-	n/a	n/a	n/a
2	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
3	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
4	Citigroup Energy Inc.	[redacted]	WSPP	n/a	n/a	n/a
5	Citigroup Energy Inc.	[redacted]	-	n/a	n/a	n/a
6	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
7	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
8	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
9	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
10	Grant CO Public Utility District #2 --	SF	WSPP	n/a	n/a	n/a
11	IBERDROLA RENEWABLES, Inc.	[redacted]	WSPP	n/a	n/a	n/a
12	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
13	IBERDROLA RENEWABLES, Inc.	[redacted]	WSPP	n/a	n/a	n/a
14	J.P. Morgan Ventures Energy Corporation	[redacted]	-	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		770,334		770,334	1
170,572		3,910,214		3,910,214	2
3,251		75,238		75,238	3
3		93		93	4
		4,324,363		4,324,363	5
165,250		5,158,976		5,158,976	6
321		544		544	7
27,628		741,529		741,529	8
4,400		48,892		48,892	9
600		8,850		8,850	10
			20,474	20,474	11
14,977		384,149		384,149	12
29,380		206,149		206,149	13
		46,560		46,560	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
2	J.P. Morgan Chase Bank, N.A.	[redacted]	WSPP	n/a	n/a	n/a
3	Jeffries Bache	[redacted]	-	n/a	n/a	n/a
4	Macquarie Energy LLC	[redacted]	WSPP	n/a	n/a	n/a
5	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
6	Macquarie Energy LLC	[redacted]	WSPP	n/a	n/a	n/a
7	Morgan Stanley Capital Group Inc.	[redacted]	WSPP	n/a	n/a	n/a
8	NextEra Energy Power Marketing, LLC	SF	WSPP	n/a	n/a	n/a
9	Noble Americas Gas & Power corp.	SF	WSPP	n/a	n/a	n/a
10	NorthWestern Energy	[redacted]	WSPP	n/a	n/a	n/a
11	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
12	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
13	PacifiCorp Inc.	[redacted]	WSPP	n/a	n/a	n/a
14	PacifiCorp Inc.	[redacted]	T-7	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,600		69,584		69,584	1
		66,515		66,515	2
		6,390,737		6,390,737	3
		744,771		744,771	4
520,986		10,201,383		10,201,383	5
4,500		32,115		32,115	6
			70,126	70,126	7
650		3,700		3,700	8
4,000		36,000		36,000	9
29,892		83,106		83,106	10
86		2,333		2,333	11
53,381		1,194,384		1,194,384	12
607		8,583		8,583	13
139		3,017		3,017	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 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	Portland General Electric Company	[redacted]	WSPP	n/a	n/a	n/a
2	Portland General Electric Company	[redacted]	WSPP	n/a	n/a	n/a
3	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
4	Powerex Corp.	[redacted]	WSPP	n/a	n/a	n/a
5	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
6	PPL EnergyPlus, LLC	[redacted]	WSPP	n/a	n/a	n/a
7	PPL EnergyPlus, LLC	[redacted]	WSPP	n/a	n/a	n/a
8	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
9	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
10	Puget Sound Energy, Inc.	[redacted]	WSPP	n/a	n/a	n/a
11	Rainbow Energy Marketing Corporation	[redacted]	WSPP	n/a	n/a	n/a
12	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
13	Royal Bank of Canada	[redacted]	-	n/a	n/a	n/a
14	Seattle City Light	[redacted]	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
			187	187	1
500		8,450		8,450	2
10,200		227,585		227,585	3
68,282		716,707		716,707	4
27,580		309,325		309,325	5
			5,383	5,383	6
1,113		8,860		8,860	7
4,316		80,444		80,444	8
5,937		101,787		101,787	9
4,145		53,390		53,390	10
			65,710	65,710	11
166,796		3,512,095		3,512,095	12
		749,628		749,628	13
525		11,075		11,075	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Seattle City Light	SF	WSPP	n/a	n/a	n/a
2	Shell Energy North America (US), L.P.	[redacted]	WSPP	n/a	n/a	n/a
3	Shell Energy North America (US), L.P.	[redacted]	WSPP	n/a	n/a	n/a
4	Shell Energy North America (US), L.P.	[redacted]	WSPP	n/a	n/a	n/a
5	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
6	Sierra Pacific Power Co., dba NV Energy	[redacted]	T-7	n/a	n/a	n/a
7	Sierra Pacific Power Co., dba NV Energy	[redacted]	WSPP	n/a	n/a	n/a
8	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
9	Tenaska Power Services Co.	[redacted]	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.	[redacted]	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.	[redacted]	WSPP	n/a	n/a	n/a
14	TransAlta Energy Marketing (U.S.) Inc.	[redacted]	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
8,574		232,685		232,685	1
		325,722		325,722	2
			24,613	24,613	3
14,914		264,149		264,149	4
424,110		9,424,227		9,424,227	5
137		3,053		3,053	6
			85,860	85,860	7
200		4,600		4,600	8
			67	67	9
3,200		68,800		68,800	10
			637	637	11
5,340		130,942		130,942	12
			5,284	5,284	13
26,516		237,872		237,872	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
2	[redacted]	LF	61	n/a	n/a	n/a
3	Prior Year Adjustments	AD	-	n/a	n/a	n/a
4	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
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**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
121,283		2,520,399		2,520,399	1
		25,467		25,467	2
		-3		-3	3
			46,071	46,071	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

Schedule Page: 310 Line No.: 4 Column: b
Non-Firm Sales

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

Schedule Page: 310 Line No.: 7 Column: b
ISDA Master Agreement with Barclays Bank dated May 2, 2011

Schedule Page: 310 Line No.: 10 Column: b
Non-Firm Sales

Schedule Page: 310 Line No.: 14 Column: b
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 1 Column: b
ISDA Master Agreement with Cargill Power Markets LLC, dated June 13, 2011

Schedule Page: 310.1 Line No.: 4 Column: b
Non-Firm Sales

Schedule Page: 310.1 Line No.: 5 Column: b
ISDA Master Agreement with Citigroup Energy, Inc., dated March 7, 2011

Schedule Page: 310.1 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 13 Column: b
Non-Firm Sales

Schedule Page: 310.1 Line No.: 14 Column: b
ISDA Master Agreement with JP Morgan Ventures Energy Corporation dated May 1, 2011

Schedule Page: 310.2 Line No.: 2 Column: b
ISDA Master Agreement with JP Morgan Chase Bank, N.A. dated November 4, 2005

Schedule Page: 310.2 Line No.: 3 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated Septmber 4, 2008

Schedule Page: 310.2 Line No.: 4 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

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

Schedule Page: 310.2 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 10 Column: b
Non-Firm Sales

Schedule Page: 310.2 Line No.: 13 Column: b
Non-Firm Sales

Schedule Page: 310.2 Line No.: 14 Column: b
Spinning or Operating Reserves

Schedule Page: 310.3 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 2 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 4 Column: b
Non-Firm Sales

Schedule Page: 310.3 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 7 Column: b
Non-Firm Sales

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

Schedule Page: 310.3 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 13 Column: b

ISDA Master Agreement with Royal Bank of Canada dated August 26, 2005

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

Non-Firm Sales

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

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

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

Financial Transmission Losses

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

Non-Firm Sales

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

Spinning or Operating Reserves

Schedule Page: 310.4 Line No.: 7 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

Schedule Page: 310.4 Line No.: 14 Column: b

Non-Firm Sales

Schedule Page: 310.5 Line No.: 2 Column: a

Contract expiration date 05/31/2013

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	1,402,743	1,690,161
5	(501) Fuel	134,501,103	119,844,954
6	(502) Steam Expenses	8,279,623	6,950,410
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,539,354	2,231,309
10	(506) Miscellaneous Steam Power Expenses	8,331,843	9,734,263
11	(507) Rents	285,311	498,085
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	154,339,977	140,949,182
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	331,355	2,075,559
16	(511) Maintenance of Structures	759,002	920,609
17	(512) Maintenance of Boiler Plant	12,605,603	15,351,039
18	(513) Maintenance of Electric Plant	5,139,307	6,827,635
19	(514) Maintenance of Miscellaneous Steam Plant	4,996,617	6,486,063
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,831,884	31,660,905
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	178,171,861	172,610,087
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	7,437,986	5,380,371
45	(536) Water for Power	7,810,554	8,772,110
46	(537) Hydraulic Expenses	12,715,046	12,513,192
47	(538) Electric Expenses	1,376,025	1,611,582
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,634,251	3,081,121
49	(540) Rents	329,209	209,213
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	32,303,071	31,567,589
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	305,070	1,763,673
54	(542) Maintenance of Structures	1,329,157	1,722,862
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,343,402	1,563,284
56	(544) Maintenance of Electric Plant	3,114,538	1,789,947
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,071,383	2,719,281
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,163,550	9,559,047
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,466,621	41,126,636

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,342,636	820,192
63	(547) Fuel	24,912,210	11,696,917
64	(548) Generation Expenses	2,167,816	749,804
65	(549) Miscellaneous Other Power Generation Expenses	403,386	779,335
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	28,826,048	14,046,248
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	208,028	179,520
71	(553) Maintenance of Generating and Electric Plant	99,722	115,128
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,537,689	1,861,365
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,845,439	2,156,013
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	31,671,487	16,202,261
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	190,640,708	156,873,749
77	(556) System Control and Load Dispatching	2,250	1,219
78	(557) Other Expenses	-57,611,492	41,459,600
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	133,031,466	198,334,568
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	384,341,435	428,273,552
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,580,561	3,326,891
84			
85	(561.1) Load Dispatch-Reliability	130,631	192,086
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,170,321	1,188,357
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,345,152	1,423,636
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	97,740	102,697
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,359,494	2,252,352
94	(563) Overhead Lines Expenses	659,259	746,070
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,294,410	6,462,104
97	(566) Miscellaneous Transmission Expenses	175,701	307,899
98	(567) Rents	3,002,229	3,283,621
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,815,498	19,285,713
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	484,817	220,612
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	13,444	54,018
104	(569.2) Maintenance of Computer Software	749,101	347,776
105	(569.3) Maintenance of Communication Equipment	4,138	26,183
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,689,469	2,975,539
108	(571) Maintenance of Overhead Lines	5,293,220	3,675,361
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,530	5,474
111	TOTAL Maintenance (Total of lines 101 thru 110)	10,235,719	7,304,963
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	29,051,217	26,590,676

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	4,118,843	3,746,431
135	(581) Load Dispatching	3,549,914	3,482,055
136	(582) Station Expenses	1,157,508	1,192,869
137	(583) Overhead Line Expenses	3,786,758	3,039,224
138	(584) Underground Line Expenses	1,870,345	1,825,857
139	(585) Street Lighting and Signal System Expenses	109,636	122,065
140	(586) Meter Expenses	4,132,819	4,130,937
141	(587) Customer Installations Expenses	642,062	1,092,077
142	(588) Miscellaneous Expenses	5,622,888	5,494,553
143	(589) Rents	493,172	830,940
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,483,945	24,957,008
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	224,177	402,381
147	(591) Maintenance of Structures		5,711
148	(592) Maintenance of Station Equipment	3,819,880	3,230,860
149	(593) Maintenance of Overhead Lines	15,554,326	14,495,482
150	(594) Maintenance of Underground Lines	1,046,527	1,054,033
151	(595) Maintenance of Line Transformers	422,582	433,841
152	(596) Maintenance of Street Lighting and Signal Systems	568,715	554,042
153	(597) Maintenance of Meters	725,957	472,599
154	(598) Maintenance of Miscellaneous Distribution Plant	529,977	252,535
155	TOTAL Maintenance (Total of lines 146 thru 154)	22,892,141	20,901,484
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	48,376,086	45,858,492
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	441,306	427,283
160	(902) Meter Reading Expenses	1,379,745	2,453,647
161	(903) Customer Records and Collection Expenses	13,188,955	12,944,062
162	(904) Uncollectible Accounts	4,512,906	4,269,718
163	(905) Miscellaneous Customer Accounts Expenses	413	252
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	19,523,325	20,094,962

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	535,711	528,250
168	(908) Customer Assistance Expenses	33,737,489	44,034,548
169	(909) Informational and Instructional Expenses	295,583	82,775
170	(910) Miscellaneous Customer Service and Informational Expenses	554,027	531,823
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	35,122,810	45,177,396
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	70,376,748	67,143,039
182	(921) Office Supplies and Expenses	18,940,073	15,742,902
183	(Less) (922) Administrative Expenses Transferred-Credit	28,236,018	26,009,805
184	(923) Outside Services Employed	5,177,361	4,925,844
185	(924) Property Insurance	3,506,576	3,207,120
186	(925) Injuries and Damages	7,150,892	5,806,100
187	(926) Employee Pensions and Benefits	61,791,248	60,010,908
188	(927) Franchise Requirements	9	
189	(928) Regulatory Commission Expenses	5,692,486	3,449,337
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	493,057	552,129
192	(930.2) Miscellaneous General Expenses	4,026,891	3,750,121
193	(931) Rents	17,598	7,103
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,936,921	138,584,798
195	Maintenance		
196	(935) Maintenance of General Plant	5,160,763	4,522,111
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	154,097,684	143,106,909
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	670,512,557	709,101,987

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Cogeneration and Small Power Producers					
2	AgPower Jerome/Double A Digester	LU	-	.488	[redacted]	[redacted]
3	Allan Ravenscroft/Malad River	LU	-	NA	NA	NA
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
22,563				1,391,161		1,391,161	2
3,011			155,672	87,510		243,182	3
48,277				2,812,098		2,812,098	4
5,320				450,312		450,312	5
8,768				383,059		383,059	6
							7
331				22,136		22,136	8
1,257				85,808		85,808	9
1,252				85,385		85,385	10
4,462				423,727		423,727	11
745				52,655		52,655	12
59,966				2,768,295		2,768,295	13
28,493				1,486,303		1,486,303	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
64,726				5,424,211		5,424,211	1
9,143				672,982		672,982	2
							3
23,923				1,175,521		1,175,521	4
2,998				209,635		209,635	5
80				5,415		5,415	6
1,467				106,811		106,811	7
3,513				296,133		296,133	8
351			17,500	9,944		27,444	9
12,439				346,402		346,402	10
							11
14,698				698,483		698,483	12
15,385				825,499		825,499	13
4,179				300,983		300,983	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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	-	NA	[redacted]	[redacted]
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	[redacted]	-	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
8,576				440,062		440,062	1
6,673				330,044		330,044	2
4,936				333,110		333,110	3
11,044				725,126		725,126	4
689			26,796	19,481		46,277	5
864				8,441		8,441	6
1,514				102,934		102,934	7
16,461				433,134		433,134	8
3,789				287,733		287,733	9
1,099				11,102		11,102	10
23,731				1,284,648		1,284,648	11
21,720				1,286,024		1,286,024	12
-166				-7,850		-7,850	13
34,438				1,580,265		1,580,265	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Hammett Hill Windfarm, LLC	LU		NA	NA	NA
2	[redacted]	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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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)	
16,448				414,328		414,328	1
23,796				1,621,877		1,621,877	2
2,953				54,023		54,023	3
1,440				104,264		104,264	4
49,527				3,362,216		3,362,216	5
18,435				933,389		933,389	6
46,107				2,663,754		2,663,754	7
60,426				4,423,976		4,423,976	8
71,483				4,222,561		4,222,561	9
1,215				76,458		76,458	10
4,571				313,446		313,446	11
648				35,806		35,806	12
3,361				257,792		257,792	13
3,650				297,697		297,697	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	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	[redacted]	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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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)	
5,627				352,786		352,786	1
1,329				98,009		98,009	2
5,932				418,425		418,425	3
5,810				365,660		365,660	4
6,785				466,142		466,142	5
28,950				1,408,094		1,408,094	6
19,037				505,255		505,255	7
2,864				192,451		192,451	8
57,156				3,606,451		3,606,451	9
54,588				2,621,322		2,621,322	10
456				30,464		30,464	11
3,793				183,609		183,609	12
36,596				1,793,891		1,793,891	13
							14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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		NA	[redacted]	[redacted]
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	[redacted]	-	NA	NA	NA
14	Riverside Hydro/Mora Drop	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,921				115,851		115,851	1
19,479				368,154		368,154	2
15,103				1,587,748		1,587,748	3
61,858				5,187,761		5,187,761	4
8,640			486,150	212,535		698,685	5
32,486				1,560,718		1,560,718	6
864				49,425		49,425	7
1,258				67,177		67,177	8
896				64,112		64,112	9
							10
1,928				126,660		126,660	11
3,741				250,429		250,429	12
966				6,811		6,811	13
5,043				285,464		285,464	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Riverside Investments/Arena Drop	LU	-	NA	NA	NA
2	Rock Creek #1 Joint Venture	LU		NA	[redacted]	[redacted]
3	Rockland Wind Project	LU	-	NA	NA	NA
4	Rupert Cogen Partners/Magic Valley	LU	-	NA	NA	NA
5	Ryegrass Windfarm	LU		NA	NA	NA
6	Salmon Falls Wind Park	LU	-	NA	NA	NA
7	SE Hazelton A LP	LU	-	NA	NA	NA
8	Shorock Hydro Inc.					NA
9	Shoshone Cspp	LU	-	NA	NA	NA
10	Shoshone #2	LU	-	NA	NA	NA
11	Snake Rivery Pottery	LU	-	NA	NA	NA
12	[redacted]	LU	-	NA	NA	NA
13	[redacted]	LU		NA	[redacted]	[redacted]
14	Tasco - Nampa	[redacted]	-	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,635				121,273		121,273	1
9,948			552,508	281,419		833,927	2
249,799				14,364,815		14,364,815	3
77,014				4,921,093		4,921,093	4
13,176				344,581		344,581	5
62,085				3,154,626		3,154,626	6
24,716				1,572,582		1,572,582	7
							8
2,114				167,389		167,389	9
2,601				171,417		171,417	10
380				25,525		25,525	11
27,963				1,974,673		1,974,673	12
35,686			1,576,498	1,342,975		2,919,473	13
477				3,830		3,830	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1							1
26,209				1,375,275		1,375,275	2
32,751				1,565,157		1,565,157	3
29,247				1,448,563		1,448,563	4
81,578				4,895,289		4,895,289	5
8,766				523,243		523,243	6
17,921				437,526		437,526	7
753				50,238		50,238	8
4,494				327,315		327,315	9
977				67,778		67,778	10
27,609				1,883,240		1,883,240	11
62,833				5,250,646		5,250,646	12
				870,942		870,942	13
-2,406							14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Other Purchased Power					
2	Arizona Public Service Co.	SF	WSPP	NA	NA	NA
3	Avista Corp.	SF	T-12	NA	NA	NA
4	Avista Corp.	SF	WSPP	NA	NA	NA
5	Avista Corp.	[redacted]	WSPP	NA	NA	NA
6	Barclays Bank PLC	[redacted]		NA	NA	NA
7	Black Hills Power Inc.	SF	WSPP	NA	NA	NA
8	Bonneville Power Administration	[redacted]	WSPP	NA	NA	NA
9	Bonneville Power Administration	SF	WSPP	NA	NA	NA
10	BP Energy Company	SF	WSPP	NA	NA	NA
11	Brookfield Energy Marketing LP	SF	WSPP	NA	NA	NA
12	Calpine Energy Services, L.P.	SF	WSPP	NA	NA	NA
13	Cargill Power Markets LLC	[redacted]	WSPP	NA	NA	NA
14	Cargill Power Markets LLC	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
12,347				307,211		307,211	2
51				1,127		1,127	3
129,077				2,135,092		2,135,092	4
					221,285	221,285	5
					569,254	569,254	6
1,700				43,600		43,600	7
					284,953	284,953	8
93,776				1,852,172		1,852,172	9
54,800				578,296		578,296	10
775				12,361		12,361	11
8,800				130,092		130,092	12
					245,194	245,194	13
102,396				1,409,954		1,409,954	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Chelan Co PUD	SF	WSPP	NA	NA	NA
2	Citigroup Energy Inc.	SF	WSPP	NA	NA	NA
3	Citigroup Energy Inc.	[redacted]	-	NA	NA	NA
4	Clatskanie PUD	SF	WSPP	NA	NA	NA
5	Constellation Energy Commodities Group	[redacted]	WSPP	NA	NA	NA
6	Constellation Energy Commodities Group	SF	WSPP	NA	NA	NA
7	DB Energy Trading LLC	SF	WSPP	NA	NA	NA
8	Douglas County PUD	SF	WSPP	NA	NA	NA
9	EDF Trading North America, LLC	SF	WSPP	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
11	Grant CO Public Utility District #2 --	SF	WSPP	NA	NA	NA
12	IBERDROLA RENEWABLES, Inc.	SF	WSPP	NA	NA	NA
13	J.P. Morgan Ventures Energy Corporatio	[redacted]		NA	NA	NA
14	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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)	
8,034				121,705		121,705	1
91,625				2,281,427		2,281,427	2
					1,551,477	1,551,477	3
804				11,500		11,500	4
3				94		94	5
8,079				242,456		242,456	6
28,575				99,479		99,479	7
2,004				23,206		23,206	8
123,225				2,955,700		2,955,700	9
23,904				351,504		351,504	10
422				9,136		9,136	11
115,728				1,741,871		1,741,871	12
					112,088	112,088	13
58,800				1,170,570		1,170,570	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	JPMorgan Chase Bank, N.A.	[redacted]	-	NA	NA	NA
2	Jefferies Bache	[redacted]	-	NA	NA	NA
3	Macquarie Cook Power Inc.	SF	WSPP	NA	NA	NA
4	Macquarie Cook Power Inc.	[redacted]	-	NA	NA	NA
5	NaturEner USA, LLC	SF	WSPP	NA	NA	NA
6	Nevada Power Co, DBA NV Energy	SF	WSPP	NA	NA	NA
7	NextEra Energy Power Marketing, LLC	SF	WSPP	NA	NA	NA
8	Noble Americas Gas&Power Corp	SF	WSPP	NA	NA	NA
9	NorthWestern Energy	SF	T-7	NA	NA	NA
10	PacifiCorp Inc.	SF	T-13	NA	NA	NA
11	PacifiCorp Inc.	SF	WSPP	NA	NA	NA
12	PacifiCorp Inc.	[redacted]	WSPP	NA	NA	NA
13	Portland General Electric Company	SF	T-14	NA	NA	NA
14	Portland General Electric Company	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
					416,376	416,376	1
					2,250,030	2,250,030	2
18,825				156,461		156,461	3
					1,110,405	1,110,405	4
2				88		88	5
375				12,925		12,925	6
5,947				69,770		69,770	7
400				12,200		12,200	8
46				1,013		1,013	9
363				6,782		6,782	10
5,300				142,900		142,900	11
					104,495	104,495	12
45				1,298		1,298	13
25,464				320,478		320,478	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.

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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	Portland General Electric Company	[redacted]	WSPP	NA	NA	NA
2	Powerex Corp.	SF	WSPP	NA	NA	NA
3	PPL EnergyPlus, LLC	SF	WSPP	NA	NA	NA
4	Public Service Company of New Mexico	SF	WSPP	NA	NA	NA
5	Puget Sound Energy, Inc.	SF	T-9	NA	NA	NA
6	Puget Sound Energy, Inc.	SF	WSPP	NA	NA	NA
7	Rainbow Energy Marketing Corporation	SF	WSPP	NA	NA	NA
8	Royal Bank of Canada	[redacted]		NA	NA	NA
9	Salt River Project	SF	WSPP	NA	NA	NA
10	Seattle City Light	SF	WSPP	NA	NA	NA
11	Shell Energy North America (US), L.P.	SF	WSPP	NA	NA	NA
12	Shell Energy North America (US), L.P.	[redacted]	-	NA	NA	NA
13	Sierra Pacific Power Co., dba NV Energ	SF	T-55	NA	NA	NA
14	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	NA	NA	NA
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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)	
75				900		900	1
27,556				871,453		871,453	2
174,037				6,390,738		6,390,738	3
2,925				106,475		106,475	4
57				1,364		1,364	5
25,775				552,221		552,221	6
15,063				417,754		417,754	7
					-203,658	-203,658	8
900				39,500		39,500	9
23,670				475,718		475,718	10
47,463				717,312		717,312	11
					282,420	282,420	12
63				1,314		1,314	13
28,418				739,123		739,123	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Sierra Pacific Power Co., dba NV Energ	[redacted]	WSPP	NA	NA	NA
2	Snohomish County PUD	SF	WSPP	NA	NA	NA
3	Tacoma Power	SF	WSPP	NA	NA	NA
4	Tenaska Power Services Co.	SF	WSPP	NA	NA	NA
5	The Energy Authority, Inc.	SF	WSPP	NA	NA	NA
6	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	NA	NA	NA
7	Western Area Power Administration	SF	WSPP	NA	NA	NA
8	Raft River Energy I LLC	[redacted]	-	NA	NA	NA
9	Telocaset Wind Power Partners LLC	LU	APP-A	NA	NA	NA
10	Neal Hot Springs Unit #1	LU		NA	NA	NA
11	Net Metering Customers	[redacted]	-	NA	NA	NA
12	Oregon Solar Customers	[redacted]	-	NA	NA	NA
13	Power Exchanges					
14	Bonneville Power Administration	[redacted]	-	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
					790	790	1
1,730				22,420		22,420	2
482				7,608		7,608	3
429				6,738		6,738	4
6,495				69,458		69,458	5
15,836				272,363		272,363	6
1				71		71	7
74,625				4,549,186		4,549,186	8
314,145				17,153,270		17,153,270	9
23,692				2,262,881		2,262,881	10
811				61,649		61,649	11
314				7,954		7,954	12
							13
	61,650						14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	EDF Trading North America, LLC	[redacted]		NA	NA	NA
2	NorthWestern Energy	[redacted]	-	NA	NA	NA
3	PacifiCorp Inc.	[redacted]	-	NA	NA	NA
4	Puget Sound Energy, Inc.	[redacted]	-	NA	NA	NA
5	Powerex Corp.	[redacted]		NA	NA	NA
6	Sierra Pacific Power Co., dba NV Energ	[redacted]	-	NA	NA	NA
7	Utah Associated Municipal Power System	[redacted]	-	NA	NA	NA
8	Clatskanie PUD	EX	153	NA	NA	NA
9	Sierra Pacific Power Co., dba NV Energ	EX	WSPP	NA	NA	NA
10	Other Transactions					
11	Acct Valuation-Clatskanie PUD Exchange		-			
12	Langley Test Power Valuation	OS	-	NA	NA	NA
13	Liquidated Damages-Yellowstone Power	OS		NA	NA	NA
14	Demand Response Avoided Energy	OS		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
	92						1
		6,119					2
	170,446	257,349					3
	8						4
	29,370						5
		3,936					6
	262						7
	75,807	73,175					8
	54,678	54,678					9
							10
					-20,215	-20,215	11
				726,126		726,126	12
				-251,435		-251,435	13
				14,479,447		14,479,447	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.

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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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Boardman Assured Delivery	OS		NA	NA	NA
2	Write-Off	AD		NA	NA	NA
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				213,491		213,491	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/15/2013	2012/Q4

FOOTNOTE DATA

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

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

Schedule Page: 326.6 Line No.: 2 Column: f
Unavailable

Schedule Page: 326.6 Line No.: 12 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.

Schedule Page: 326.6 Line No.: 13 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: 326.6 Line No.: 13 Column: e
Unavailable

Schedule Page: 326.6 Line No.: 13 Column: f
Unavailable

Schedule Page: 326.6 Line No.: 14 Column: b
Non Firm Purchases

Schedule Page: 326.7 Line No.: 1 Column: b
Non Firm Purchases

Schedule Page: 326.7 Line No.: 11 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.

Schedule Page: 326.7 Line No.: 13 Column: a
Accrued additional purchased power expense subject to payment upon approval by IPUC.

Schedule Page: 326.7 Line No.: 14 Column: a
Difference between booked and scheduled energy

Schedule Page: 326.8 Line No.: 5 Column: b
Financial Transmission Losses

Schedule Page: 326.8 Line No.: 6 Column: b
ISDA Master Agreement with Barclays Bank PLC dated March 2, 2011

Schedule Page: 326.8 Line No.: 8 Column: b
Financial Transmission Losses

Schedule Page: 326.8 Line No.: 13 Column: b
ISDA Master Agreement with Cargill Power Markets, LLC, dated June 13, 2011

Schedule Page: 326.9 Line No.: 3 Column: b
ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011

Schedule Page: 326.9 Line No.: 5 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 13 Column: b
ISDA Master Agreement with JP Morgan Ventures Energy Corporation dated May 1, 2011

Schedule Page: 326.10 Line No.: 1 Column: b
ISDA Master Agreement with JP Morgan Chase Bank dated November 4, 2005

Schedule Page: 326.10 Line No.: 2 Column: b
Prudential Bache Commodities, LLC (Jefferies Bache) Futures Account Document, dated September 4, 2008

Schedule Page: 326.10 Line No.: 4 Column: b
ISDA Master Agreement with Macquarie Energy PLC dated April 12, 2011

Schedule Page: 326.10 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 326.11 Line No.: 1 Column: b
Non Firm Purchases

Schedule Page: 326.11 Line No.: 8 Column: b
ISDA Master Agreement with Royal Bank of Canada dated August 26,2005

Schedule Page: 326.11 Line No.: 12 Column: b
ISDA Master Agreement with Shell Energy North America dated November 1, 2009

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

Schedule Page: 326.12 Line No.: 8 Column: b
Unavailable

Schedule Page: 326.12 Line No.: 11 Column: b
Schedule 84 Net Metering

Schedule Page: 326.12 Line No.: 12 Column: b
Schedule 88 Oregon Solar

Schedule Page: 326.12 Line No.: 14 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 1 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 2 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 3 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 4 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 5 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 6 Column: b
Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 7 Column: b
Scheduled losses not removed with loss transactions

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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 - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
4	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
5	Cargill	Seattle City Light	Bonneville Power Administration	OS
6	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
7	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
8	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
11	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
12	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
13	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
14	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
16	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
17	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
19	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
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	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
24	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
25	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	SFP
26	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
28	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
29	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
31	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
32	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
33	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
[redacted]			[redacted]	324,580	324,580	1
5			[redacted]	376,076	376,076	2
5			[redacted]	1,243,883	1,243,883	3
[redacted]	Minidoka, Idaho	Various in Idaho	[redacted]	10,123	10,123	4
10			[redacted]	401,225	401,225	5
5			[redacted]	1,965	1,965	6
[redacted]	LaGrande, Oregon	Various in Idaho	[redacted]	18,245	18,245	7
5	AVAT.NWMT	BORA		855	855	8
5	AVAT.NWMT	BRDY		540	540	9
5	AVAT.NWMT	M345		143	143	10
5	BORA	BPAT.NWMT		10	10	11
5	BORA	BRDY		44	44	12
5	BORA	HMWY		2,088	2,088	13
5	BORA	JEFF		352	352	14
5	BORA	LAGRANDE		3,450	3,450	15
5	BORA	M345		2,242	2,242	16
5	BPAT.NWMT	BORA		410	410	17
5	BPAT.NWMT	BORA		39,557	39,557	18
5	BPAT.NWMT	BRDY		1,203	1,203	19
5	BPAT.NWMT	BRDY		4,169	4,169	20
5	BPAT.NWMT	LAGRANDE		99	99	21
5	BPAT.NWMT	M345		1,214	1,214	22
5	BPAT.NWMT	M345		672	672	23
5	BRDY	BORA		1,856	1,856	24
5	BRDY	BORA		38	38	25
5	BRDY	BPAT.NWMT		411	411	26
5	BRDY	ENPR		4	4	27
5	BRDY	HMWY		1,423	1,423	28
5	BRDY	JEFF		4	4	29
5	BRDY	LAGRANDE		2,785	2,785	30
5	BRDY	M345		1,263	1,263	31
5	ENPR	BORA		373,642	373,642	32
5	ENPR	BORA		35,034	35,034	33
5	ENPR	BRDY		26,927	26,927	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
2	BC Hydro Powerex	PacifiCorp West	Bonneville Power Administration	NF
3	BC Hydro Powerex	PacifiCorp West	Avista	NF
4	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
5	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/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	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	NF
10	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	SFP
11	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	NF
12	BC Hydro Powerex	Idaho Power Company	PacifiCorp West	NF
13	BC Hydro Powerex	Idaho Power Company	NorthWestern/PacifiCorp East	NF
14	BC Hydro Powerex	Idaho Power Company	Sierra Pacific Power	NF
15	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
16	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
17	BC Hydro Powerex	PacifiCorp West	PacifiCorp West	NF
18	BC Hydro Powerex	PacifiCorp West	Idaho Power Company	NF
19	BC Hydro Powerex	PacifiCorp West	Bonneville Power Administration	NF
20	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
21	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
24	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
25	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
26	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
27	BC Hydro Powerex	NorthWestern/PacifiCorp East	Idaho Power Company	NF
28	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
29	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
30	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
31	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
32	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	SFP
33	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
34	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	SFP
	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	ENPR	BRDY		1,816	1,816	1
5	ENPR	LAGRANDE		229	229	2
5	ENPR	LOLO		76	76	3
5	ENPR	M345		2,622	2,622	4
5	GSHN	BPAT.NWMT		5	5	5
5	GSHN	HMWY		177	177	6
5	GSHN	LAGRANDE		1,741	1,741	7
5	GSHN	M345		45	45	8
5	HMWY	BORA		73,164	73,164	9
5	HMWY	BORA		2,163	2,163	10
5	HMWY	BRDY		3,772	3,772	11
5	HMWY	JBSN		218	218	12
5	HMWY	JEFF		724	724	13
5	HMWY	M345		5,414	5,414	14
5	JBSN	BORA		82	82	15
5	JBSN	BRDY		24	24	16
5	JBSN	ENPR		67	67	17
5	JBSN	HMWY		173	173	18
5	JBSN	LAGRANDE		842	842	19
5	JBSN	M345		14	14	20
5	JBWT	LAGRANDE		35	35	21
5	JEFF	BORA		3,845	3,845	22
5	JEFF	BORA		24	24	23
5	JEFF	BPAT.NWMT		37	37	24
5	JEFF	BRDY		9,819	9,819	25
5	JEFF	BRDY		272	272	26
5	JEFF	HMWY		351	351	27
5	JEFF	JBSN		45	45	28
5	JEFF	LAGRANDE		48	48	29
5	JEFF	M345		79	79	30
5	LAGRANDE	BORA		92,482	92,482	31
5	LAGRANDE	BORA		1,201	1,201	32
5	LAGRANDE	BRDY		54,739	54,739	33
5	LAGRANDE	BRDY		17,297	17,297	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	NF
2	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	SFP
3	BC Hydro Powerex	Avista	PacifiCorp East	NF
4	BC Hydro Powerex	Avista	PacifiCorp East	SFP
5	BC Hydro Powerex	Avista	PacifiCorp East	NF
6	BC Hydro Powerex	Avista	PacifiCorp East	SFP
7	BC Hydro Powerex	Avista	Sierra Pacific Power	NF
8	BC Hydro Powerex	Avista	Sierra Pacific Power	SFP
9	BC Hydro Powerex	Sierra Pacific Power	PacifiCorp East	NF
10	BC Hydro Powerex	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
11	BC Hydro Powerex	Sierra Pacific Power	PacifiCorp East	NF
12	BC Hydro Powerex	Sierra Pacific Power	Bonneville Power Administration	NF
13	Bonneville Power Administration	PacifiCorp East	Bonneville Power Administration	NF
14	Bonneville Power Administration	NorthWestern/PacifiCorp East	PacifiCorp East	NF
15	Bonneville Power Administration	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
16	Bonneville Power Administration	PacifiCorp East	Bonneville Power Administration	NF
17	Bonneville Power Administration	PacifiCorp West	Bonneville Power Administration	NF
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
19	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
20	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
21	Bonneville Power Administration	Avista	Bonneville Power Administration	SFP
22	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
23	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
24	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
26	Cargill-Alliant	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	Cargill-Alliant	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Cargill-Alliant	PacifiCorp East	PacifiCorp East	SFP
29	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
30	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	NF
31	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	NF
32	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	SFP
33	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
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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	LAGRANDE	M345		9,467	9,467	1
5	LAGRANDE	M345		1,296	1,296	2
5	LOLO	BORA		8,133	8,133	3
5	LOLO	BORA		11,134	11,134	4
5	LOLO	BRDY		1,886	1,886	5
5	LOLO	BRDY		2,059	2,059	6
5	LOLO	M345		1,999	1,999	7
5	LOLO	M345		586	586	8
5	M345	BORA		155	155	9
5	M345	BPAT.NWMT		701	701	10
5	M345	BRDY		61	61	11
5	M345	LAGRANDE		1,067	1,067	12
5	BORA	LAGRANDE		306	306	13
5	BPAT.NWMT	BRDY		717	717	14
5	BPAT.NWMT	LAGRANDE		546	546	15
5	BRDY	LAGRANDE		717	717	16
5	ENPR	LAGRANDE		300	300	17
5	LAGRANDE	LAGRANDE		2,334	2,334	18
5	LAGRANDE	M345		8,144	8,144	19
5	LOLO	LAGRANDE		3,509	3,509	20
5	LOLO	LAGRANDE		720	720	21
5	LOLO	M345		1,756	1,756	22
5	LOLO	OTEC		1	1	23
5	AVAT.NWMT	M345		70	70	24
5	AVAT.NWMT	M345		72	72	25
5	BORA	AVAT.NWMT		459	459	26
5	BORA	BPAT.NWMT		150	150	27
5	BORA	BRDY		800	800	28
5	BORA	ENPR		3,884	3,884	29
5	BORA	LAGRANDE		1,776	1,776	30
5	BORA	M345		4,232	4,232	31
5	BORA	M345		1,448	1,448	32
5	BPAT.NWMT	BORA		1,468	1,468	33
5	BPAT.NWMT	BORA		8,827	8,827	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	BPAT.NWMT	BRDY		60	60	1
5	BPAT.NWMT	LAGRANDE		109	109	2
5	BPAT.NWMT	M345		8,109	8,109	3
5	BPAT.NWMT	M345		16,361	16,361	4
5	BRDY	AVAT.NWMT		200	200	5
5	BRDY	BORA		544	544	6
5	BRDY	BPAT.NWMT		25	25	7
5	BRDY	LAGRANDE		383	383	8
5	BRDY	M345		16,036	16,036	9
5	BRDY	M345		3,756	3,756	10
5	ENPR	BORA		55,633	55,633	11
5	ENPR	BORA		26,345	26,345	12
5	ENPR	M345		100	100	13
5	ENPR	M345		400	400	14
5	HCPR	BORA		1,096	1,096	15
5	HCPR	BORA		216	216	16
5	HCPR	M345		960	960	17
5	JBSN	M345		1,220	1,220	18
5	JBSN	M345		4,104	4,104	19
5	JEFF	BORA		107	107	20
5	JEFF	BRDY		671	671	21
5	JEFF	M345		10,766	10,766	22
5	LAGRANDE	BORA		7,587	7,587	23
5	LAGRANDE	BORA		1,021	1,021	24
5	LAGRANDE	BRDY		1,114	1,114	25
5	LAGRANDE	JBSN		10	10	26
5	LAGRANDE	M345		8,084	8,084	27
5	LAGRANDE	M345		736	736	28
5	LOLO	BORA		13,689	13,689	29
5	LOLO	BORA		11,490	11,490	30
5	LOLO	BRDY		1,542	1,542	31
5	LOLO	M345		52,221	52,221	32
5	LOLO	M345		16,981	16,981	33
5	LYPK	BORA		9,558	9,558	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	SFP
2	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
4	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	SFP
5	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	NF
6	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	SFP
7	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
8	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP
9	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	NF
10	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	SFP
11	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	LFP
12	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	NF
13	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	SFP
14	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
15	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
16	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
17	Cargill-Alliant	Idaho Power Company	PacifiCorp East	NF
18	Cargill-Alliant	Idaho Power Company	NorthWestern/PacifiCorp East	NF
19	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	NF
20	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	SFP
21	Citigroup Energy			NF
22	Eagle Energy Partners	PacifiCorp West	PacifiCorp East	NF
23	Eagle Energy Partners	Bonneville Power Administration	PacifiCorp East	NF
24	Iberdrola Energy	PacifiCorp East	Idaho Power Company	NF
25	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
26	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
27	Iberdrola Energy	PacifiCorp East	Sierra Pacific Power	NF
28	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
29	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
30	Iberdrola Energy	Idaho Power Company	Sierra Pacific Power	NF
31	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
32	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
33	Iberdrola Energy	Bonneville Power Administration	Sierra Pacific Power	NF
34	Iberdrola Energy	Avista	PacifiCorp East	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LYPK	BORA		63,560	63,560	1
5	LYPK	BPAT.NWMT		525	525	2
5	LYPK	BRDY		269	269	3
5	LYPK	BRDY		303	303	4
5	LYPK	JBSN		150	150	5
5	LYPK	JBSN		169	169	6
5	LYPK	JEFF		255	255	7
5	LYPK	JEFF		4,557	4,557	8
5	LYPK	LAGRANDE		2,495	2,495	9
5	LYPK	LAGRANDE		51	51	10
5	LYPK	LAGRANDE		6,995	6,995	11
5	LYPK	M345		20,441	20,441	12
5	LYPK	M345		261,496	261,496	13
5	M345	AVAT.NWMT		15	15	14
5	M345	BRDY		239	239	15
5	M345	JEFF		44	44	16
5	OBBLPR	BORA		231	231	17
5	OBBLPR	BPAT.NWMT		82	82	18
5	OBBLPR	M345		1,024	1,024	19
5	OBBLPR	M345		608	608	20
5						21
5	ENPR	BORA		1,767	1,767	22
5	LAGRANDE	BORA		107	107	23
5	BORA	HMWY		45	45	24
5	BORA	LAGRANDE		310	310	25
5	BRDY	LAGRANDE		155	155	26
5	BRDY	M345		173	173	27
5	HMWY	BORA		4,255	4,255	28
5	HMWY	BRDY		941	941	29
5	HMWY	M345		6,148	6,148	30
5	LAGRANDE	BORA		3,912	3,912	31
5	LAGRANDE	BRDY		63	63	32
5	LAGRANDE	M345		3,934	3,934	33
5	LOLO	BORA		29	29	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Iberdrola Energy	Avista	Sierra Pacific Power	NF
2	Iberdrola Energy	Sierra Pacific Power	PacifiCorp East	NF
3	Iberdrola Energy	Sierra Pacific Power	Bonneville Power Administration	NF
4	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
5	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp East	NF
8	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
10	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp East	NF
16	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp East	SFP
17	Morgan Stanley Capital Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
20	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp East	NF
21	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp West	NF
22	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
23	Morgan Stanley Capital Group	Idaho Power Company	PacifiCorp East	NF
24	Morgan Stanley Capital Group	Idaho Power Company	PacifiCorp East	NF
25	Morgan Stanley Capital Group	Idaho Power Company	Sierra Pacific Power	NF
26	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp East	NF
27	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp East	NF
28	Morgan Stanley Capital Group	PacifiCorp West	Sierra Pacific Power	NF
29	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
30	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
31	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
32	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
33	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	LOLO	M345		145	145	1
5	M345	BORA		50	50	2
5	M345	LAGRANDE		842	842	3
5	AVAT.NWMT	BRDY		146	146	4
5	AVAT.NWMT	LAGRANDE		6	6	5
5	AVAT.NWMT	M345		236	236	6
5	BORA	BRDY		292	292	7
5	BORA	LAGRANDE		5	5	8
5	BORA	M345		463	463	9
5	BPAT.NWMT	BORA		251	251	10
5	BPAT.NWMT	BRDY		45	45	11
5	BPAT.NWMT	LAGRANDE		206	206	12
5	BPAT.NWMT	M345		1,301	1,301	13
5	BRDY	AVAT.NWMT		35	35	14
5	BRDY	BORA		2,628	2,628	15
5	BRDY	BORA		4,560	4,560	16
5	BRDY	BPAT.NWMT		27	27	17
5	BRDY	LAGRANDE		12,846	12,846	18
5	BRDY	M345		7,507	7,507	19
5	ENPR	BORA		131	131	20
5	ENPR	JBSN		437	437	21
5	GSHN	BPAT.NWMT		50	50	22
5	HMWY	BORA		143	143	23
5	HMWY	BRDY		45	45	24
5	HMWY	M345		1,843	1,843	25
5	JBSN	BORA		4,204	4,204	26
5	JBSN	BRDY		656	656	27
5	JBSN	M345		200	200	28
5	JEFF	BORA		17,863	17,863	29
5	JEFF	BORA		795	795	30
5	JEFF	BRDY		633	633	31
5	JEFF	LAGRANDE		4,509	4,509	32
5	JEFF	M345		12,949	12,949	33
5	JEFF	M345		926	926	34
			0	6,075,120	6,075,120	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 Capital Group	Bonneville Power Administration	PacifiCorp East	NF
2	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp East	NF
3	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp West	NF
4	Morgan Stanley Capital Group	Bonneville Power Administration	Sierra Pacific Power	NF
5	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
6	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
7	Morgan Stanley Capital Group	Avista	PacifiCorp West	NF
8	Morgan Stanley Capital Group	Avista	Sierra Pacific Power	NF
9	Morgan Stanley Capital Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
10	Morgan Stanley Capital Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
11	Morgan Stanley Capital Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
12	Morgan Stanley Capital Group	Sierra Pacific Power	Bonneville Power Administration	NF
13	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
14	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	LFP
15	Pacificorp Power Marketing	PacifiCorp East	Bonneville Power Administration	NF
16	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
17	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	SFP
18	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
19	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
20	Pacificorp Power Marketing	PacifiCorp West	Bonneville Power Administration	NF
21	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
22	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
23	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
24	Pacificorp Power Marketing	Idaho Power Company	Idaho Power Company	LFP
25	Pacificorp Power Marketing	Idaho Power Company	Bonneville Power Administration	NF
26	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	LFP
27	Pacificorp Power Marketing	Bonneville Power Administration	PacifiCorp East	NF
28	Pacificorp Power Marketing	Bonneville Power Administration	PacifiCorp East	SFP
29	Pacificorp Power Marketing	Avista	PacifiCorp East	NF
30	Pacificorp Power Marketing	Avista	PacifiCorp West	NF
31	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
32	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
33	Portland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF
34	PPL Energy Plus	PacifiCorp East	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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		342	342	1
5	LAGRANDE	BRDY		2,355	2,355	2
5	LAGRANDE	JBSN		1,257	1,257	3
5	LAGRANDE	M345		3,412	3,412	4
5	LOLO	BORA		66	66	5
5	LOLO	BRDY		15	15	6
5	LOLO	JBSN		2	2	7
5	LOLO	M345		375	375	8
5	M345	AVAT.NWMT		75	75	9
5	M345	BPAT.NWMT		204	204	10
5	M345	JEFF		33	33	11
5	M345	LAGRANDE		315	315	12
5	BORA	ENPR		2,290	2,290	13
5	BORA	KPRT	[redacted]	643,617	643,617	14
5	BORA	LAGRANDE		794	794	15
5	BORA	M345		1,921	1,921	16
5	BRDY	BORA		1,939	1,939	17
5	BRDY	BRDY		3,895	3,895	18
5	ENPR	BORA		98,299	98,299	19
5	ENPR	LAGRANDE		241	241	20
5	ENPR	M345		556	556	21
5	JBWT	BRDY		398,590	398,590	22
5	JBWT	ENPR		11,242	11,242	23
5	JBWT	HMWY		347,275	347,275	24
5	JBWT	LAGRANDE		12,820	12,820	25
5	JBWT	M500		272,299	272,299	26
5	LAGRANDE	BORA		29,588	29,588	27
5	LAGRANDE	BORA		6,262	6,262	28
5	LOLO	BORA		33,621	33,621	29
5	LOLO	ENPR		201	201	30
5	BORA	LAGRANDE		50	50	31
5	JEFF	LAGRANDE		105	105	32
5	M345	LAGRANDE		50	50	33
5	BRDY	LAGRANDE		968	968	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	PPL Energy Plus	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	PPL Energy Plus	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	PPL Energy Plus	Avista	PacifiCorp East	NF
4	PPL Energy Plus	Avista	PacifiCorp West	NF
5	Puget Sound Energy	Bonneville Power Administration	Sierra Pacific Power	NF
6	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
7	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
8	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
10	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	NF
11	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	SFP
12	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	NF
13	Rainbow Energy Marketing	PacifiCorp West	NorthWestern/PacifiCorp East	SFP
14	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
15	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	Rainbow Energy Marketing	Avista	PacifiCorp East	NF
17	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
18	Rainbow Energy Marketing	Avista	Sierra Pacific Power	NF
19	Rainbow Energy Marketing	Avista	Sierra Pacific Power	SFP
20	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
21	Shell Energy	PacifiCorp East	Sierra Pacific Power	NF
22	Shell Energy	Idaho Power Company	PacifiCorp East	NF
23	Shell Energy	Idaho Power Company	Sierra Pacific Power	NF
24	Shell Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	Shell Energy	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Shell Energy	Bonneville Power Administration	PacifiCorp East	NF
27	Shell Energy	Bonneville Power Administration	Sierra Pacific Power	NF
28	Shell Energy	Bonneville Power Administration	Sierra Pacific Power	SFP
29	Shell Energy	Avista	Sierra Pacific Power	NF
30	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
31	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
32	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
33	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
34	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	JEFF	BRDY		211	211	1
5	JEFF	LAGRANDE		3,844	3,844	2
5	LOLO	BRDY		180	180	3
5	LOLO	JBSN		280	280	4
5	LAGRANDE	M345		210	210	5
5	AVAT.NWMT	BORA		301	301	6
5	BORA	M345		1,515	1,515	7
5	BPAT.NWMT	BORA		553	553	8
5	BPAT.NWMT	BORA		9,381	9,381	9
5	JBSN	BORA		28	28	10
5	JBSN	BORA		2,114	2,114	11
5	JBSN	BRDY		61	61	12
5	JBSN	JEFF		685	685	13
5	JEFF	BORA		969	969	14
5	JEFF	BRDY		21	21	15
5	LOLO	BORA		46,623	46,623	16
5	LOLO	BORA		19,117	19,117	17
5	LOLO	M345		940	940	18
5	LOLO	M345		2,527	2,527	19
5	BRDY	LAGRANDE		2,723	2,723	20
5	BRDY	M345		4,041	4,041	21
5	HMWY	BRDY		241	241	22
5	HMWY	M345		4,551	4,551	23
5	JEFF	LAGRANDE		544	544	24
5	JEFF	M345		1,224	1,224	25
5	LAGRANDE	BRDY		392	392	26
5	LAGRANDE	M345		5,417	5,417	27
5	LAGRANDE	M345		2,686	2,686	28
5	LOLO	M345		6	6	29
5	LYPK	BRDY		100	100	30
5	LYPK	LAGRANDE		73	73	31
5	M345	BRDY		279	279	32
5	M345	LAGRANDE		3,602	3,602	33
5	MDSK	LAGRANDE		442	442	34
			0	**6,075,120**	**6,075,120**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
2	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
3	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
4	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
5	Sierra Pacific Power Marketing	Idaho Power Company	Sierra Pacific Power	NF
6	Sierra Pacific Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
7	Sierra Pacific Power Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
8	Sierra Pacific Power Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
9	Sierra Pacific Power Marketing	Avista	Sierra Pacific Power	NF
10	Sierra Pacific Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
11	Sierra Pacific Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
12	Sierra Pacific Power Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
13	Tenaska	Bonneville Power Administration	PacifiCorp East	NF
14	The Energy Authority	Idaho Power Company	PacifiCorp East	NF
15	The Energy Authority	Bonneville Power Administration	PacifiCorp East	NF
16	The Energy Authority	Bonneville Power Administration	PacifiCorp East	NF
17	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
18	Transalta Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
19	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Transalta Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Transalta Energy Marketing	PacifiCorp East	PacifiCorp East	NF
23	Transalta Energy Marketing	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
24	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
25	Transalta Energy Marketing	Bonneville Power Administration	Avista	NF
26	Transalta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
27	Transalta Energy Marketing	Avista	PacifiCorp East	NF
28	Transalta Energy Marketing	Avista	Sierra Pacific Power	NF
29	Transalta Energy Marketing	Sierra Pacific Power	PacifiCorp East	NF
30	Transalta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
31	Transalta Energy Marketing	Idaho Power Company	PacifiCorp East	NF
32	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
33				
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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 (Substation 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	MNHM	LAGRANDE		16	16	1
5	BORA	M345		2,085	2,085	2
5	BRDY	M345		36,131	36,131	3
5	BRDY	M345		4,920	4,920	4
5	HMWY	M345		3,346	3,346	5
5	JBSN	M345		905	905	6
5	JEFF	M345		28,490	28,490	7
5	LAGRANDE	M345		4,201	4,201	8
5	LOLO	M345		19,793	19,793	9
5	M345	BORA		50	50	10
5	M345	BRDY		215	215	11
5	M345	LAGRANDE		425	425	12
5	LAGRANDE	BORA		97	97	13
5	HMWY	BORA		290	290	14
5	LAGRANDE	BORA		801	801	15
5	LAGRANDE	BRDY		24	24	16
5	BORA	LAGRANDE		767	767	17
5	BORA	M345		97	97	18
5	BPAT.NWMT	BORA		15	15	19
5	BPAT.NWMT	BRDY		74	74	20
5	BPAT.NWMT	M345		8	8	21
5	BRDY	BORA		43	43	22
5	GSHN	LAGRANDE		180	180	23
5	LAGRANDE	BORA		6,335	6,335	24
5	LAGRANDE	LOLO		85	85	25
5	LAGRANDE	M345		964	964	26
5	LOLO	BORA		85	85	27
5	LOLO	M345		16	16	28
5	M345	BORA		12	12	29
5	M345	LAGRANDE		267	267	30
5	OBBLPR	BORA		84	84	31
5	BORA	M345		8,833	8,833	32
						33
						34
			0	**6,075,120**	**6,075,120**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,110,520	135,121		1,245,641	1
1,398,847	156,231		1,555,078	2
4,182,977	315,408		4,498,385	3
	16,400		16,400	4
	331,490		331,490	5
6,841	1,246		8,087	6
54,640			54,640	7
	3,230		3,230	8
	2,040		2,040	9
	540		540	10
	38		38	11
	166		166	12
	7,887		7,887	13
	1,330		1,330	14
	13,032		13,032	15
	8,469		8,469	16
	1,549		1,549	17
	149,423		149,423	18
	4,544		4,544	19
	15,748		15,748	20
	374		374	21
	4,586		4,586	22
	2,538		2,538	23
	7,011		7,011	24
	144		144	25
	1,553		1,553	26
	15		15	27
	5,375		5,375	28
	15		15	29
	10,520		10,520	30
	4,771		4,771	31
	1,411,400		1,411,400	32
	132,338		132,338	33
	101,714		101,714	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
	6,860		6,860	1
	865		865	2
	287		287	3
	9,904		9,904	4
	19		19	5
	669		669	6
	6,576		6,576	7
	170		170	8
	276,371		276,371	9
	8,171		8,171	10
	14,248		14,248	11
	823		823	12
	2,735		2,735	13
	20,451		20,451	14
	310		310	15
	91		91	16
	253		253	17
	653		653	18
	3,181		3,181	19
	53		53	20
	132		132	21
	14,524		14,524	22
	91		91	23
	140		140	24
	37,090		37,090	25
	1,027		1,027	26
	1,326		1,326	27
	170		170	28
	181		181	29
	298		298	30
	349,343		349,343	31
	4,537		4,537	32
	206,772		206,772	33
	65,338		65,338	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
	35,761		35,761	1
	4,896		4,896	2
	30,722		30,722	3
	42,058		42,058	4
	7,124		7,124	5
	7,778		7,778	6
	7,551		7,551	7
	2,214		2,214	8
	585		585	9
	2,648		2,648	10
	230		230	11
	4,031		4,031	12
	1,292		1,292	13
	3,026		3,026	14
	2,305		2,305	15
	3,026		3,026	16
	1,266		1,266	17
	9,851		9,851	18
	34,375		34,375	19
	14,811		14,811	20
	3,039		3,039	21
	7,412		7,412	22
	4		4	23
	275		275	24
	283		283	25
	1,806		1,806	26
	590		590	27
	3,147		3,147	28
	15,279		15,279	29
	6,987		6,987	30
	16,649		16,649	31
	5,696		5,696	32
	5,775		5,775	33
	34,725		34,725	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
	236		236	1
	429		429	2
	31,901		31,901	3
	64,364		64,364	4
	787		787	5
	2,140		2,140	6
	98		98	7
	1,507		1,507	8
	63,085		63,085	9
	14,776		14,776	10
	218,858		218,858	11
	103,640		103,640	12
	393		393	13
	1,574		1,574	14
	4,312		4,312	15
	850		850	16
	3,777		3,777	17
	4,799		4,799	18
	16,145		16,145	19
	421		421	20
	2,640		2,640	21
	42,353		42,353	22
	29,847		29,847	23
	4,017		4,017	24
	4,382		4,382	25
	39		39	26
	31,802		31,802	27
	2,895		2,895	28
	53,852		53,852	29
	45,201		45,201	30
	6,066		6,066	31
	205,436		205,436	32
	66,803		66,803	33
	37,601		37,601	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
	250,043		250,043	1
	2,065		2,065	2
	1,058		1,058	3
	1,192		1,192	4
	590		590	5
	665		665	6
	1,003		1,003	7
	17,927		17,927	8
	9,815		9,815	9
	201		201	10
	27,518		27,518	11
	80,414		80,414	12
	1,028,717		1,028,717	13
	59		59	14
	940		940	15
	173		173	16
	909		909	17
	323		323	18
	4,028		4,028	19
	2,392		2,392	20
	4		4	21
	6,294		6,294	22
	381		381	23
	162		162	24
	1,116		1,116	25
	558		558	26
	623		623	27
	15,323		15,323	28
	3,389		3,389	29
	22,140		22,140	30
	14,088		14,088	31
	227		227	32
	14,167		14,167	33
	104		104	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
	522		522	1
	180		180	2
	3,032		3,032	3
	580		580	4
	24		24	5
	938		938	6
	1,161		1,161	7
	20		20	8
	1,840		1,840	9
	998		998	10
	179		179	11
	819		819	12
	5,171		5,171	13
	139		139	14
	10,445		10,445	15
	18,123		18,123	16
	107		107	17
	51,055		51,055	18
	29,836		29,836	19
	521		521	20
	1,737		1,737	21
	199		199	22
	568		568	23
	179		179	24
	7,325		7,325	25
	16,708		16,708	26
	2,607		2,607	27
	795		795	28
	70,994		70,994	29
	3,160		3,160	30
	2,516		2,516	31
	17,920		17,920	32
	51,464		51,464	33
	3,680		3,680	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,359		1,359	1
	9,360		9,360	2
	4,996		4,996	3
	13,561		13,561	4
	262		262	5
	60		60	6
	8		8	7
	1,490		1,490	8
	298		298	9
	811		811	10
	131		131	11
	1,252		1,252	12
	11,931		11,931	13
				14
	4,137		4,137	15
	10,008		10,008	16
	10,102		10,102	17
	20,293		20,293	18
	512,127		512,127	19
	1,256		1,256	20
	2,897		2,897	21
	2,076,610		2,076,610	22
	58,570		58,570	23
	1,809,265		1,809,265	24
	66,791		66,791	25
	1,418,648		1,418,648	26
	154,150		154,150	27
	32,624		32,624	28
	175,162		175,162	29
	1,047		1,047	30
	275		275	31
	577		577	32
	275		275	33
	3,181		3,181	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
	693		693	1
	12,632		12,632	2
	591		591	3
	920		920	4
	510		510	5
	916		916	6
	4,611		4,611	7
	1,683		1,683	8
	28,553		28,553	9
	85		85	10
	6,434		6,434	11
	186		186	12
	2,085		2,085	13
	2,949		2,949	14
	64		64	15
	141,905		141,905	16
	58,186		58,186	17
	2,861		2,861	18
	7,691		7,691	19
	14,753		14,753	20
	21,894		21,894	21
	1,306		1,306	22
	24,657		24,657	23
	2,947		2,947	24
	6,631		6,631	25
	2,124		2,124	26
	29,349		29,349	27
	14,553		14,553	28
	33		33	29
	542		542	30
	396		396	31
	1,512		1,512	32
	19,516		19,516	33
	2,395		2,395	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
	87		87	1
	6,894		6,894	2
	119,462		119,462	3
	16,267		16,267	4
	11,063		11,063	5
	2,992		2,992	6
	94,197		94,197	7
	13,890		13,890	8
	65,442		65,442	9
	165		165	10
	711		711	11
	1,405		1,405	12
	626		626	13
	792		792	14
	2,187		2,187	15
	66		66	16
	2,841		2,841	17
	359		359	18
	56		56	19
	274		274	20
	30		30	21
	159		159	22
	667		667	23
	23,462		23,462	24
	315		315	25
	3,570		3,570	26
	315		315	27
	59		59	28
	44		44	29
	989		989	30
	311		311	31
	33,201		33,201	32
				33
				34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

5, 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

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.: 3 Column: h

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 20, 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.: 4 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

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

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

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

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

Schedule Page: 328 Line No.: 6 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.: 7 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 7 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: 328.6 Line No.: 14 Column: h

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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: Megawatt-hours Received (c)	TRANSFER OF ENERGY: Megawatt-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	34,954	34,954		251,314		251,314
2	Avista Corp-WWP Div	SFP	319,770	319,770		1,556,759		1,556,759
3	Bonneville Power Admin	[redacted]	268,990	268,990	1,531,616			1,531,616
4	[redacted]	OS					7,453	7,453
5	Bonneville Power Admin	NF	1,127	1,127		13,345		13,345
6	Bonneville Power Admin	SFP	1,997	1,997		12,539		12,539
7	[redacted]	OS					-1,944	-1,944
8	Northwestern Energy	[redacted]	20,259	20,259	199,600			199,600
9	NorthWesern Energy	NF	1,993	1,993		10,947		10,947
10	NorthWestern Energy	SFP	83,567	83,567		557,646		557,646
11	PacifiCorp Inc.	[redacted]	52,522	52,522		922,740		922,740
12	PacifiCorp Inc.	NF	23,600	23,600		249,998		249,998
13	PacifiCorp Inc.	SFP	14,331	14,331		121,385		121,385
14	Portland General Ele Co	SFP	93,739	93,739		333,877		333,877
15	[redacted]	OS					-239,216	-239,216
16	PPL EnergyPlus, LLC	SFP	4,032	4,032		13,859		13,859
	TOTAL		1,024,122	1,024,122	1,731,216	4,796,901	-233,707	6,294,410

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Puget Sound Energy, Inc	SFP	3,736	3,736		4,870		4,870
2	Seattle City Light	SFP	94,344	94,344		732,422		732,422
3	Sierra Pacific Power Co	NF	769	769		6,068		6,068
4	Snohomish County PUD	SFP	4,392	4,392		9,132		9,132
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,024,122	1,024,122	1,731,216	4,796,901	-233,707	6,294,410

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/15/2013	2012/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 3 Column: b

Contract Expiration Date 09/30/2016

Schedule Page: 332 Line No.: 4 Column: a

Reserves Provided

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

Resale Transmission

Schedule Page: 332 Line No.: 8 Column: b

Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 11 Column: b

Contract Expiration Date 05/31/2014

Schedule Page: 332 Line No.: 15 Column: a

Resale Transmission

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	410,105
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	405,305
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Richard Dahl	81,888
7	Christine King	77,294
8	Gary Michael	141,582
9	Richard Reiten	26,144
10	Joan Smith	77,365
11	Jan Packwood	54,750
12	Judith Johansen	72,526
13	Thomas Wilford	69,428
14	Robert Tintsman	78,828
15	Stephen Allred	70,559
16		
17	Chamber of Commerce & Other Civic Organizations	123,491
18		
19	Association of Idaho Cities	2,300
20	Associated Taxpayers of Idaho	22,000
21	Boston College Center for Corporation	5,000
22	Corporate Executive Board	42,750
23	Idaho Association of Commerce & Industry	3,000
24	Idaho Association of Counties	350
25	Idaho Technology Council	10,000
26	National Association of Directors	5,558
27	National HydroPower Association	28,000
28	North American Energy Standard	6,500
29	Northwest Power Pool	131,093
30	Pacific Northwest Utilities	36,824
31	Western Electricity Coordinating Council	837,673
32	Western Energy Institute	28,110
33	Wyoming Taxpayers Association	1,500
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	4,026,891

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

Recipient	Purpose	Amount
Broadridge Financial Solutions	Proxy & Bulletin	$ 43,589
Deutsche Bank	Broker Fees	35,048
E Source	Mgmt Services	35,432
Moody's Analytics	Broker Services	30,285
New York Stock Exchange	Listing fees	52,976
Port of Morrow	Misc Expenses	5,475
PR Newswire	Misc Expense	13,825
Rate Related Amortization	Misc Expense	230,657
Rivel Research Group	Mgmt Services	11,880
Stock Based Compensation	Stock Expense	576,000
Thomson Financial/Carson	Analyst Service	105,197
Misc		36,604
Total		$1,176,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,483,540		7,483,540
2	Steam Production Plant	21,748,286	317,075			22,065,361
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,287,651				14,287,651
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,903,496				10,903,496
7	Transmission Plant	18,110,510				18,110,510
8	Distribution Plant	40,970,148				40,970,148
9	Regional Transmission and Market Operation					
10	General Plant	10,390,099				10,390,099
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	116,113,891	317,075	7,483,540		123,914,506

B. Basis for Amortization Charges

Account 404 - Basis used to compute charges:

	Balance 1/1/12	2012 Amortization	Balance 12/31/12	Remaining months
(1)	12,000	12,000	60,000	12
(2)	11,976,335	545,446	11,430,888	-
(3)		47,195	5,626,910	357
(4)	18,068,415	6,582,974	15,481,590	-
(5)	4,611,695	287,899	4,323,796	192
(6)	225,899	8,026	217,873	-
Total	34,894,344	7,483,540	37,141,058	

(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 Relicenisng (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).

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		3.71	R4.0	20.20
13	311.00	147,710	100.00	-10.00	1.70	S1.0	21.30
14	312.10	81,667	60.00	-5.00	1.52	R3.0	21.80
15	312.20	477,479	60.00	-5.00	2.53	R1.5	20.90
16	312.30	4,204	25.00	20.00	2.38	R3.0	7.90
17	314.00	147,772	45.00	-5.00	2.84	S1.0	19.40
18	315.00	68,200	60.00		6.82	S1.5	19.80
19	316.00	14,053	45.00	-5.00	6.60	R0.5	19.00
20	316.10	87	12.00	15.00	8.82	L2.0	6.30
21	316.40	240	12.00	15.00	4.37	L2.0	7.90
22	316.50	83	12.00	15.00	4.33	L2.0	5.10
23	316.60	106	20.00	15.00	4.09	L2.0	18.00
24	316.70	80	20.00	15.00	2.83	L2.0	14.40
25	316.80	1,054	20.00	30.00	8.13	O1.0	16.60
26	316.90	14	35.00	15.00	2.25	S1.0	34.70
27	317.00	10,214					
28	Subtotal Steam	953,596					
29	331.00	157,518	100.00	-25.00	2.52	R2.5	33.00
30	332.10	19,460	95.00	-20.00	1.71	S4.0	39.80
31	332.20	228,211	95.00	-20.00	1.88	S4.0	35.60
32	332.30	5,472			2.03	SQUARE	49.10
33	333.00	200,844	80.00	-5.00	1.81	R3.0	32.60
34	334.00	46,647	50.00	-5.00	2.85	R1.5	26.10
35	335.00	19,686	95.00		2.19	R2.0	28.10
36	335.10	76	15.00		5.41	SQUARE	6.50
37	335.20	364	20.00		4.72	SQUARE	5.30
38	335.30	166	5.00		14.43	SQUARE	3.30
39	336.00	8,118	75.00		2.23	R3.0	21.40
40	Subtotal Hydro	686,562					
41	341.00	133,026			2.89	SQUARE	27.20
42	342.00	7,988	50.00		2.90	S2.5	28.50
43	343.00	226,811	40.00		3.26	S1.5	25.90
44	344.00	73,447	45.00		2.48	S2.0	26.80
45	345.00	95,558	50.00		3.21	S1.5	22.60
46	346.00	5,739	35.00		3.14	S2.5	24.50
47	Subtotal Other	542,569					
48	350.20	31,171	70.00		1.39	R3.0	58.80
49	352.00	70,137	65.00	-35.00	1.84	R3.0	53.70
50	353.00	365,355	50.00	6.00	1.90	R1.5	40.70

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	354.00	155,096	65.00	-15.00	1.70	S3.0	50.80
13	355.00	120,356	60.00	-70.00	2.77	R2.0	43.60
14	356.00	182,332	65.00	-40.00	2.25	R2.0	48.50
15	359.00	390	65.00		0.79	R2.5	24.00
16	Subtotal Transmission	924,837					
17	360.22	32	30.00		3.33		30.00
18	361.00	31,354	65.00	-40.00	2.14	R2.5	53.30
19	362.00	189,665	50.00	-5.00	2.00	R1.0	40.20
20	364.00	230,356	44.00	-45.00	3.08	R1.5	31.30
21	365.00	124,012	45.00	-35.00	2.98	R0.5	33.60
22	366.00	46,834	60.00	-20.00	1.95	R2.0	48.40
23	367.00	197,732	46.00	-15.00	2.26	R2.0	35.30
24	368.00	451,212	35.00	-3.00	2.58	R1.0	27.00
25	369.00	56,853	40.00	-40.00	2.55	R2.0	29.50
26	370.00	14,182	22.00	1.00	3.46	O1.0	17.50
27	370.10	56,751	15.00		6.96	S2.5	13.10
28	370.30						
29	371.10	27	12.00	-2.00	2.35	S4.0	9.00
30	371.20	2,838	17.00	-2.00	1.51	R1.5	14.70
31	373.20	4,505	30.00	-25.00	2.41	R1.0	20.60
32	374.00	644					
33	Subtotal Distribution	1,406,997					
34	390.11	27,395	100.00	-5.00	2.58	S0.5	28.80
35	390.12	65,695	55.00	-5.00	1.90	S0.5	44.30
36	390.20	563	35.00		2.15	S3.0	25.70
37	391.11	12,769	20.00		2.88	SQUARE	12.90
38	391.20	21,438	5.00		11.12	SQUARE	3.20
39	391.21	8,588	8.00		11.22	L2.0	5.70
40	392.10	766	12.00	15.00	7.50	L2.0	8.90
41	392.30	2,590	10.00	50.00	1.73	S2.5	3.40
42	392.40	19,800	12.00	15.00	7.36	L2.0	6.80
43	392.50	882	12.00	15.00	3.53	L2.0	9.00
44	392.60	30,787	20.00	15.00	4.14	L2.0	13.40
45	392.70	5,635	20.00	15.00	3.21	L2.0	12.50
46	392.90	4,431	35.00	15.00	2.10	S1.0	24.30
47	393.00	1,878	25.00		3.30	SQUARE	19.40
48	394.00	6,466	20.00		4.13	SQUARE	13.30
49	395.00	12,255	20.00		4.29	SQUARE	12.10
50	396.00	11,496	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	5,582	15.00		4.25	SQUARE	8.30
13	397.20	27,115	15.00		5.38	SQUARE	9.80
14	397.30	3,612	15.00		5.31	SQUARE	8.00
15	397.40	3,621	10.00		7.90	SQUARE	6.50
16	398.00	5,622	15.00		5.20	SQUARE	10.60
17	Subtotal General	278,986					
18	Total Plant	4,793,547					
19							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,862,917		3,862,917	
3					
4	Regulatory FERC fees Tru-up		381,035	381,035	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		326,544	326,544	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Intervenor funding		150,024	150,024	
13	PURPA expenses		270,004	270,004	
14	Rate Case - Misc expenses		4,712	4,712	
15					
16	Regulatory Commission Expenses - Oregon				
17	Rate Case - Misc expenses		9,755	9,755	
18					
19	Other - OPUC				
20	UE - 233		150,392	150,392	
21	UE - 244		39,012	39,012	
22	UE - 248		19,098	19,098	
23	UM - 1182		30,421	30,421	
24	UM - 1559		26,890	26,890	
25	UM - 1562		50,113	50,113	
26	UM - 1572		52,332	52,332	
27	UM - 1575		26,573	26,573	
28	PURPA		32,513	32,513	
29	General Regulatory		19,785	19,785	
30	Other OPUC expenses		81,865	81,865	
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,021,418	1,671,068	5,692,486	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	3,862,917					2
							3
Electric	928	381,035					4
							5
							6
Electric	928	326,544					7
							8
		158,501					9
							10
							11
Electric	928	150,024					12
Electric	928	270,004					13
Electric	928	4,712					14
							15
							16
Electric	928	9,755					17
							18
							19
Electric	928	150,392					20
Electric	928	39,012					21
Electric	928	19,098					22
Electric	928	30,421					23
Electric	928	26,890					24
Electric	928	50,113					25
Electric	928	52,332					26
Electric	928	26,573					27
Electric	928	32,513					28
Electric	928	19,785					29
Electric	928	81,865					30
							31
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		5,692,486					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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 2012.	
3		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	20,049,754		
4	Transmission	6,731,505		
5	Regional Market			
6	Distribution	17,301,055		
7	Customer Accounts			
8	Customer Service and Informational	8,412,128		
9	Sales	4,648,046		
10	Administrative and General	42,810,041		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	99,952,529		
12	Maintenance			
13	Production	6,116,531		
14	Transmission	3,404,348		
15	Regional Market			
16	Distribution	9,416,231		
17	Administrative and General	1,164,994		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,102,104		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,166,285		
21	Transmission (Enter Total of lines 4 and 14)	10,135,853		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	26,717,286		
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)	8,412,128		
26	Sales (Transcribe from line 9)	4,648,046		
27	Administrative and General (Enter Total of lines 10 and 17)	43,975,035		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	120,054,633		120,054,633
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	120,054,633		120,054,633
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant	54,744,367		54,744,367
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	54,744,367		54,744,367
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	4,918,559		4,918,559
79	Other Clearing Accounts	3,064,354		3,064,354
80	Other work in progress	1,882,252		1,882,252
81	Paid absences	20,732,543		20,732,543
82	Preliminary survey and investigation	93,565		93,565
83	Other accounts	5,062,314		5,062,314
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	35,753,587		35,753,587
96	TOTAL SALARIES AND WAGES	210,552,587		210,552,587

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	4,441	27	900	3,220	203	567		451	
2	February	4,439	7	900	3,055	201	567		616	
3	March	4,438	2	800	3,109	212	567		550	
4	Total for Quarter 1	13,318			9,384	616	1,701		1,617	
5	April	4,564	23	1600	3,100	216	567		681	
6	May	4,791	14	1900	3,436	269	567		519	
7	June	5,544	28	2000	4,472	337	567		168	
8	Total for Quarter 2	14,899			11,008	822	1,701		1,368	
9	July	5,864	12	1600	4,861	342	567		94	
10	August	5,489	8	1800	4,482	303	567		137	
11	September	4,720	4	2100	3,773	255	567		125	
12	Total for Quarter 3	16,073			13,116	900	1,701		356	
13	October	4,243	26	900	3,367	182	567		127	
14	November	4,362	12	1900	3,499	193	567		103	
15	December	4,499	18	900	3,660	200	567		72	
16	Total for Quarter 4	13,104			10,526	575	1,701		302	
17	Total Year to Date/Year	57,394			44,034	2,913	6,804		3,643	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	5,227,055
4	Nuclear	
5	Hydro-Conventional	7,956,343
6	Hydro-Pumped Storage	
7	Other	675,603
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	13,859,001
10	Purchases	3,667,462
11	Power Exchanges:	
12	Received	392,313
13	Delivered	395,257
14	Net Exchanges (Line 12 minus line 13)	-2,944
15	Transmission For Other (Wheeling)	
16	Received	[redacted]
17	Delivered	6,075,120
18	Net Transmission for Other (Line 16 minus line 17)	-988
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,522,531

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,085,316
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,183,262
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,253,953
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,522,531

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,514,978	265,515	2,130	17	8 AM
30	February	1,434,240	323,075	2,021	6	8 AM
31	March	1,467,239	384,924	1,949	2	8 AM
32	April	1,386,222	302,871	2,073	23	4 PM
33	May	1,555,433	259,416	2,296	21	6 PM
34	June	1,529,723	12,232	2,927	28	8 PM
35	July	1,785,648	8,655	3,245	12	4 PM
36	August	1,649,308	14,344	3,086	7	6 PM
37	September	1,294,520	85,446	2,385	5	7 PM
38	October	1,246,951	168,622	1,832	2	2 PM
39	November	1,228,647	158,090	1,908	27	8 AM
40	December	1,429,622	200,072	2,133	19	8 AM
41	TOTAL	17,522,531	2,183,262			

Schedule Page: 401 Line No.: 16 Column: b

Page 329 column I differs from Page 401 by 988 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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	[redacted]			[redacted]		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	[redacted]			[redacted]		
6	Net Peak Demand on Plant - MW (60 minutes)	717			60		
7	Plant Hours Connected to Load	8784			5561		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	[redacted]			[redacted]		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	4374213000			230176000		
13	Cost of Plant: Land and Land Rights	106610			494358		
14	Structures and Improvements	13910931			66823285		
15	Equipment Costs	60588342			460074757		
16	Asset Retirement Costs	0			0		
17	Total Cost	74605883			527392400		
18	Cost per KW of Installed Capacity (line 17/5) Including	96.8279			8214.8349		
19	Production Expenses: Oper, Supv, & Engr	222901			590272		
20	Fuel	103402312			4991249		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5203040			424389		
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	6278439			473728		
27	Rents	285311			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	133909			197376		
30	Maintenance of Structures	0			166		
31	Maintenance of Boiler (or reactor) Plant	8136821			128927		
32	Maintenance of Electric Plant	2261009			1817633		
33	Maintenance of Misc Steam (or Nuclear) Plant	4717009			36324		
34	Total Production Expenses	130640751			8660064		
35	Expenses per Net KWh	0.0299			0.0376		
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	2404401	6419	0	140346	1243	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9325	140000	0	8345	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.245	142.680	0.000	30.960	134.052	0.000
41	Average Cost of Fuel per Unit Burned	42.626	98.502	0.000	34.221	128.858	0.000
42	Average Cost of Fuel Burned per Million BTU	2.275	16.752	0.000	2.046	22.104	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.022	0.000	0.000
44	Average BTU per KWh Net Generation	10307.000	0.000	0.000	10228.000	0.000	0.000

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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
[redacted]	2001	2005	3
1985	2008	2005	4
[redacted]	270.90	172.80	5
261	224	178	6
7881	541	397	7
0	261	164	8
[redacted]	0	0	9
0	0	0	10
0	9	4	11
622666000	72685000	53194000	12
1106140	402745	0	13
66975806	5679993	1471166	14
274376410	107792021	58946771	15
0	0	0	16
342458356	113874759	60417937	17
1207.9660	420.3572	349.6408	18
589570	344837	148572	19
26107543	5908249	3626466	20
0	0	0	21
2652194	0	0	22
0	0	0	23
0	0	0	24
1539354	294777	277326	25
1579676	103559	43651	26
0	0	0	27
0	0	0	28
71	0	0	29
758837	80801	73394	30
4339854	4922	38360	31
1060665	2087452	289155	32
243285	0	0	33
38871049	8824597	4496924	34
0.0624	0.1214	0.0845	35

(d)			(e)			(f)			Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
346327	14997	0	764057	0	0	568185	0	0	38
9853	138778	0	1027	0	0	1027	0	0	39
36.543	132.895	0.000	7.733	0.000	0.000	6.383	0.000	0.000	40
69.462	132.880	0.000	7.733	0.000	0.000	6.383	0.000	0.000	41
3.525	22.798	0.000	5.440	0.000	0.000	4.480	0.000	0.000	42
0.042	0.000	0.000	0.081	0.000	0.000	0.068	0.000	0.000	43
11101.000	0.000	0.000	10796.000	0.000	0.000	10970.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	305	0
7	Plant Hours Connected to Load	1907	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	16	0
12	Net Generation, Exclusive of Plant Use - KWh	549705000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	125862894	0
15	Equipment Costs	241906961	0
16	Asset Retirement Costs	0	0
17	Total Cost	370057116	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1162.0572	0
19	Production Expenses: Oper, Supv, & Engr	727729	0
20	Fuel	16873841	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	1597922	0
26	Misc Steam (or Nuclear) Power Expenses	226959	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	45424	0
31	Maintenance of Boiler (or reactor) Plant	17345	0
32	Maintenance of Electric Plant	186031	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	19675251	0
35	Expenses per Net KWh	0.0358	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	2261741	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	7.461	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	7.461	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.350	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	4226.000	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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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

(d)			(e)			(f)			Line No.
									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

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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: 402 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: 402 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: 402 Line No.: 9 Column: d

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	[redacted]	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)	100	77
7	Plant Hours Connect to Load	6,872	8,784
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	352,580,000	367,568,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,358
15	Structures and Improvements	11,855,142	1,085,815
16	Reservoirs, Dams, and Waterways	4,293,075	8,413,888
17	Equipment Costs	31,904,332	8,423,020
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,767,143	19,177,558
21	Cost per KW of Installed Capacity (line 20 / 5)	539.1890	255.7008
22	Production Expenses		
23	Operation Supervision and Engineering	476,609	927,261
24	Water for Power	1,577,186	628,163
25	Hydraulic Expenses	97,084	597,445
26	Electric Expenses	51,463	48,134
27	Misc Hydraulic Power Generation Expenses	63,884	79,638
28	Rents	155	3,034
29	Maintenance Supervision and Engineering	13,233	23,041
30	Maintenance of Structures	124,229	72,264
31	Maintenance of Reservoirs, Dams, and Waterways	243	276,980
32	Maintenance of Electric Plant	234,659	63,965
33	Maintenance of Misc Hydraulic Plant	82,341	130,468
34	Total Production Expenses (total 23 thru 33)	2,721,086	2,850,393
35	Expenses per net KWh	0.0077	0.0078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	[redacted]		1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
677	14	217	6
8,784	7,530	8,784	7
			8
747	15	221	9
220	1	202	10
6	2	6	11
2,299,399,000	52,931,000	1,092,370,000	12
			13
18,089,244	82,142	1,210,187	14
32,265,720	7,364,154	9,979,198	15
67,073,285	3,145,630	30,435,631	16
57,797,955	12,601,622	15,814,524	17
518,444	122,668	565,842	18
0	0	0	19
175,744,648	23,316,216	58,005,382	20
300.2129	1,877.3121	305.2915	21
			22
561,426	220,588	331,280	23
402,168	212,942	221,975	24
924,182	448,127	514,955	25
289,589	179,333	157,482	26
645,433	303,217	427,938	27
195,636	112	32,214	28
44,343	15,314	28,653	29
166,643	37,386	235,793	30
238,438	4,236	47,778	31
465,035	201,474	237,479	32
486,572	76,454	220,503	33
4,419,465	1,699,183	2,456,050	34
0.0019	0.0321	0.0022	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	441	24
7	Plant Hours Connect to Load	8,772	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,084,203,000	167,365,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,870,863	2,794,963
16	Reservoirs, Dams, and Waterways	52,738,008	6,262,987
17	Equipment Costs	18,085,610	4,403,230
18	Roads, Railroads, and Bridges	819,192	309,805
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	76,390,974	13,976,361
21	Cost per KW of Installed Capacity (line 20 / 5)	195.1238	642.0010
22	Production Expenses		
23	Operation Supervision and Engineering	404,945	272,806
24	Water for Power	271,901	686,421
25	Hydraulic Expenses	632,125	163,775
26	Electric Expenses	156,482	37,579
27	Misc Hydraulic Power Generation Expenses	534,981	32,552
28	Rents	53,355	0
29	Maintenance Supervision and Engineering	47,425	13,111
30	Maintenance of Structures	58,661	19,136
31	Maintenance of Reservoirs, Dams, and Waterways	294,579	38,130
32	Maintenance of Electric Plant	375,770	156,049
33	Maintenance of Misc Hydraulic Plant	1,002,621	106,508
34	Total Production Expenses (total 23 thru 33)	3,832,845	1,526,067
35	Expenses per net KWh	0.0018	0.0091

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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
93	23	51	6
8,780	8,754	6,898	7
			8
91	24	53	9
84	14	50	10
5	4	4	11
464,505,000	127,279,000	166,426,000	12
			13
5,476,746	51,675	255,499	14
9,266,487	25,469,343	10,891,616	15
10,697,169	13,856,887	7,908,870	16
12,306,266	30,416,395	20,731,334	17
248,183	835,946	1,917,603	18
0	0	0	19
37,994,851	70,630,246	41,704,922	20
458.8750	2,825.2098	790.7645	21
			22
1,090,503	766,824	343,165	23
689,076	402,783	180,435	24
1,005,259	503,308	168,886	25
70,368	14,618	53,776	26
131,381	77,054	46,602	27
32,673	8,014	1,122	28
25,825	17,358	8,672	29
56,461	62,762	38,469	30
122,743	86,970	15,145	31
341,903	215,803	122,610	32
125,736	110,956	140,702	33
3,691,928	2,266,450	1,119,584	34
0.0079	0.0178	0.0067	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	8,784	6,035
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	218,236,000	65,937,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,027,032	1,231,506
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	8,693,529	4,550,600
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	16,521,490	6,659,219
21	Cost per KW of Installed Capacity (line 20 / 5)	478.8838	532.7375
22	Production Expenses		
23	Operation Supervision and Engineering	547,441	286,537
24	Water for Power	337,882	139,168
25	Hydraulic Expenses	578,598	116,243
26	Electric Expenses	64,611	31,015
27	Misc Hydraulic Power Generation Expenses	86,664	35,336
28	Rents	0	30
29	Maintenance Supervision and Engineering	16,266	12,583
30	Maintenance of Structures	110,854	101,919
31	Maintenance of Reservoirs, Dams, and Waterways	171,031	901
32	Maintenance of Electric Plant	57,080	118,936
33	Maintenance of Misc Hydraulic Plant	96,409	69,371
34	Total Production Expenses (total 23 thru 33)	2,066,836	912,039
35	Expenses per net KWh	0.0095	0.0138

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	60	59	6
0	8,773	5,464	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	248,940,000	175,182,000	12
			13
114,367	424,428	138,100	14
26,681,738	2,826,153	10,354,284	15
13,556,785	6,920,148	17,114,934	16
1,792,250	8,062,473	27,720,868	17
99,051	88,693	501,877	18
0	0	0	19
42,244,191	18,321,895	55,830,063	20
0.0000	305.3649	939.1096	21
			22
0	681,142	395,884	23
0	285,885	1,716,901	24
6,559,288	240,393	79,771	25
0	95,961	34,738	26
78	78,931	65,495	27
0	1,311	1,553	28
0	22,026	12,366	29
0	60,939	115,036	30
0	5,757	7,949	31
0	336,611	118,770	32
130,569	106,936	56,008	33
6,689,935	1,915,892	2,604,471	34
0.0000	0.0077	0.0149	35

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

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

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

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

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

Upstream storage in Brownlee Reservoir

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	16,883	1,759,923
3	Thousand Springs	1912	8.80	7.5	56,539	9,359,404
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	3.0	19	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
703,969	167,698		150,624			2
1,063,569	223,097		152,979			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
						12
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	76.04		2
8	Kinport	Borah	345.00	345.00	S Tower	27.10		1
9	Midpoint	Borah #1	345.00	345.00	H Wood	79.31		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	11.05		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	4,778.91	11.02	190

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	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	21,787,333	22,043,714					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		836,006	836,006					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,889,116	17,372,425					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	6,380,747	6,663,890					9
715.5 ACSR	64,851	12,281,414	12,346,265					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	5,537,611	5,599,829					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	3,058,249	3,166,550					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	2,198,731	2,612,524					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	1,748,214	7,009,570	8,757,784					24
715.5 ACSR								25
1272 ACSR	3,062,812	6,980,098	10,042,910					26
795 AAC		80,895	80,895					27
954 ACSR	34,174	16,026,470	16,060,644					28
2X954 ACSR	236,152	9,192,894	9,429,046					29
1272 ACSR								30
1272 ACSR	81,701	1,666,354	1,748,055					31
1590 ACSR	624,917	22,457,621	23,082,538					32
1590 ACSR		15,210,561	15,210,561					33
1590 ACSR								34
1590 ACSR								35
	31,516,529	460,340,116	491,856,645	7,159,365	5,779,567	3,002,229	15,941,161	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.37		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	41.32		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	48.43		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	11.10		2
31	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.35		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	4,778.91	11.02	190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	
1590 ACSR		3,528,033	3,528,033					1
1590 ACSR	1,854,996	9,212,985	11,067,981					2
1590 ACSR	948,166	9,078,827	10,026,993					3
1272 ACSR								4
715.5 ACSR	385,287	5,595,136	5,980,423					5
715.5 ACSR								6
795 ACSR	53,068	2,799,473	2,852,541					7
795 ACSR								8
VARIOUS	289,934	9,016,582	9,306,516					9
1272 ACSR	14,810	1,241,047	1,255,857					10
715.5 ACSR	227,825	6,920,209	7,148,034					11
VARIOUS								12
1272 ACSR	87,468	2,171,101	2,258,569					13
1272 ACSR	171,081	1,540,515	1,711,596					14
1272 ACSR	44,687	1,252,130	1,296,817					15
954 ACSR	185,106	6,269,304	6,454,410					16
715.5 ACSR	247,857	11,784,046	12,031,903					17
1272 ACSR	84,014	1,881,398	1,965,412					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	1,737,526	1,813,567					24
397.5 ACSR								25
								26
250 COPPER	26,507	338,681	365,188					27
250 COPPER								28
715.5 ACSR	21,327	249,232	270,559					29
795 AAC	646,112	3,152,590	3,798,702					30
795 ACSR	47,687	3,545,932	3,593,619					31
795 ACSR	43,568	913,613	957,181					32
795 AAC	270,823	557,504	828,327					33
VARIOUS	564,932	3,768,756	4,333,688					34
VARIOUS								35
	31,516,529	460,340,116	491,856,645	7,159,365	5,779,567	3,002,229	15,941,161	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
2	King	Lower Malad	138.00	138.00	H Wood	84.78		2
3	Emmett Jct	Payette	138.00	138.00	H Wood	66.41		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	141.74		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	73.74		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	7.50		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	18.47		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	25.20		2
32	Twin Falls	Russett	138.00	138.00	S P Wood	1.72		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	4,778.91	11.02	190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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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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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
VARIOUS								1
VARIOUS	76,823	2,302,594	2,379,417					2
VARIOUS	30,918	2,511,404	2,542,322					3
397.5 ACSR	1,955	6,930	8,885					4
VARIOUS	34,428	4,811,314	4,845,742					5
715.5 ACSR	216,919	8,271,471	8,488,390					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	122,591	125,332					11
VARIOUS	28,490	2,150,317	2,178,807					12
VARIOUS	173,683	3,037,531	3,211,214					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	8,219,053	11,342,433					17
VARIOUS								18
795AAC								19
1272 ACSR								20
250 COPPER	450	187,848	188,298					21
397.5 ACSR	349,712	7,062,297	7,412,009					22
397.5 ACSR								23
397.5 ACSR	109,899	2,306,969	2,416,868					24
397.5 ACSR								25
715.5 ACSR	211,131	1,448,294	1,659,425					26
715.5 ACSR	3,324	1,430,523	1,433,847					27
397.5 ACSR	14,927	587,404	602,331					28
715.5 ACSR	13,734	1,051,324	1,065,058					29
397.5 ACSR	18,223	1,276,855	1,295,078					30
VARIOUS	54,848	3,084,397	3,139,245					31
715.5 ACSR	16,790	206,158	222,948					32
715.5 ACSR	13,616	491,359	504,975					33
397.5 ACSR	395,696	3,449,949	3,845,645					34
715.5 ACSR	343,955	2,137,516	2,481,471					35
	31,516,529	460,340,116	491,856,645	7,159,365	5,779,567	3,002,229	15,941,161	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

TRANSMISSION LINE STATISTICS

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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.
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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.
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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	13.15		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	6.53		1
5	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.24	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	2.08		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	34.53		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	1.24		2
27	Donn	HOKU	138.00	138.00	S P Steel	2.68		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	4,778.91	11.02	190

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 ACSR								1
715.5 ACSR	14,697	637,273	651,970					2
795 AAC		49,642	49,642					3
795 AAC	489,037	2,177,222	2,666,259					4
1272 ACSR	935,725	3,605,765	4,541,490					5
1272 ACSR	34,687	838,605	873,292					6
715.5 ACSR	179,817	2,909,434	3,089,251					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		351,497	351,497					24
1272 ACSR	377,296		377,296					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		-11,446	-11,446					31
1590 ACSR		70,224	70,224					32
250 COPPER	58	64,441	64,499					33
715.5 ACSR		76,560	76,560					34
397.5 ACSR		4,406	4,406					35
	31,516,529	460,340,116	491,856,645	7,159,365	5,779,567	3,002,229	15,941,161	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	C J Strike	Strike Jct	138.00	138.00	S Tower	4.32		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	68.24		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	10.48		1
8	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		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	938.98		1
18								
19								
20	46 Kv Lines		46.00	46.00	S P Wood	407.98		1
21								
22	Total all lines					4,778.91	11.02	190
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,778.91	11.02	190

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
715.5 ACSR	1,074	398,891	399,965					1
397.5 ACSR	4,355	2,259,099	2,263,454					2
715.5 ACSR	86,651	1,866,338	1,952,989					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	1,507,287	51,235,189	52,742,476					16
VARIOUS								17
								18
								19
VARIOUS	194,536	14,758,767	14,953,303					20
								21
				7,159,365	5,779,567	3,002,229	15,941,161	22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	31,516,529	460,340,116	491,856,645	7,159,365	5,779,567	3,002,229	15,941,161	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Langley Gulch	Galloway Rd (str. #117)	14.26	s pole	8.13	1	1
2	Galloway Rd	Willis Tap	2.09	s pole	15.70	1	1
3							
4	King	Justice	0.11	w pole	36.03	1	1
5							
6	Bowmont	Happy Valley	8.60	s pole		1	1
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		25.06		59.86	4	4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1590	ACSR	TAS-BP&H-FRA	138	948,166	5,447,296	3,631,531		10,026,993	1
1272	ACSR	TAS	138						2
									3
1590	ACSR	TVS-BP	138		24,530	45,694		70,224	4
									5
1272	ACSR	TVS	138		377,296			377,296	6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
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									42
									43
				948,166	5,849,122	3,677,225		10,474,513	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
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
		5				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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Chestnut	distribution	138.00	13.00	
11	Clear Lake - attended	transmission	46.00	2.40	
12	Cliff	transmission	138.00	46.00	12.50
13	Cliff	transmission	138.00	46.00	12.95
14	Cloverdale	distribution	138.00	13.00	
15	Dale	distribution	46.00	4.60	
16	Dale	distribution	46.00	13.00	
17	Dale	distribution	69.00	13.00	
18	Dale	distribution	138.00	36.20	
19	Dale	transmission	138.00	46.00	12.47
20	Danskin- attended	transmission	230.00	18.00	
21	Danskin- attended	transmission	230.00	138.00	13.80
22	Danskin- attended	distribution	18.00	4.16	
23	Danskin- attended	transmission	138.00	12.00	
24	Danskin- attended	distribution	35.00	13.80	
25	Don	distribution	138.00	7.60	
26	Don	distribution	138.00	13.20	
27	Don	distribution	138.00	13.00	
28	Don	distribution	14.00		
29	DRAM	distribution	138.00	13.09	
30	DRAM	transmission	230.00	138.00	13.80
31	DRAM	distribution	138.00	12.47	
32	Duffin	distribution	138.00	35.00	
33	Eagle	distribution	138.00	13.09	
34	Eastgate	distribution	138.00		
35	Eastgate	distribution	138.00	13.00	
36	Eckert	distribution	138.00	36.20	
37	Eden	distribution	138.00	36.20	
38	Eden	transmission	138.00	46.00	12.98
39	Elkhorn	distribution	138.00	12.47	
40	Elkhorn	distribution	138.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
120	1					1
24	1					2
75	3					3
120	1					4
		1				5
15	1					6
15	1					7
12	1					8
10	1					9
48	2					10
4	1					11
12	2	1				12
4	1					13
48	2					14
		1				15
		6				16
		1				17
27	1					18
25	1					19
140	1					20
180	1					21
6	1					22
96	2					23
5	1					24
		1				25
108	6	3				26
26	1	1				27
80	6					28
118	7					29
160	2					30
17	1					31
36	2					32
38	2					33
24	1					34
18	1					35
18	1					36
24	1					37
15	1					38
8	1					39
8	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Elmore	distribution	138.00	35.00	
2	Elmore	transmission	138.00	69.00	12.50
3	Elmore	transmission	138.00	69.00	12.98
4	Emmett	distribution	138.00		
5	Emmett	transmission	138.00	69.00	12.47
6	Falls	distribution	46.00	13.00	
7	Filer	distribution	46.00	13.00	
8	Flying H	distribution	69.00	2.40	
9	Fort Hall	distribution	46.00	13.00	
10	Fossil Gulch	distribution	138.00	35.00	
11	Fremont	transmission	138.00	46.00	12.50
12	Gary	distribution	138.00	13.09	
13	Gary	distribution	138.00	13.00	
14	Gem	distribution	69.00	13.00	
15	Gem	distribution	69.00		
16	Goodng Rural	distribution	46.00	13.00	
17	Golden Valley	distribution	69.00	13.00	
18	Gowen Substation	distribution	138.00	35.00	
19	Grindstone	distribution	35.00		
20	Grove	distribution	138.00	13.09	
21	Grove	distribution	138.00	13.00	
22	Hagerman	distribution	46.00	13.00	
23	Hagerman	distribution	46.00	13.00	32.00
24	Hailey	distribution	138.00	13.00	
25	Happy Valley	distribution	138.00	13.09	
26	Haven	distribution	138.00	35.00	
27	Haven	transmission	138.00	46.00	
28	[redacted]	transmission	500.00	230.00	34.50
29	Hewlett Packard	distribution	138.00	13.00	
30	Hidden Springs	distribution	138.00	13.00	
31	Highland	distribution	138.00	13.00	
32	Hill	distribution	138.00	13.00	
33	Hillsdale	distribution	138.00		
34	Hoku	distribution	138.00	13.80	
35	Homedale	distribution	69.00	13.00	
36	Horse Flat	transmission	230.00	138.00	13.80
37	Horseshoe Bend	distribution	35.00		
38	Horseshoe Bend	distribution	69.00	36.20	
39	Horseshoe Bend	distribution	69.00	25.00	
40	Huston	distribution	69.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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.
17	1					1
15	1					2
15	1					3
24	1					4
25	1					5
18	2					6
10	1					7
15	2					8
10	1	1				9
15	1					10
50	3	1				11
20	1					12
17	1					13
8	1					14
10	1					15
15	2					16
10	1	1				17
24	1					18
5	2					19
48	2					20
24	1					21
10	1					22
5	1					23
20	1					24
18	1					25
12	1					26
25	1					27
600	3	1				28
20	1					29
8	1					30
18	1					31
39	2					32
24	1					33
		2				34
22	2					35
100	1					36
5	1					37
12	1					38
5	1					39
10	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Hulen	distribution	46.00	13.00	
2	Hunt	transmission	230.00	138.00	13.80
3	Hydra	distribution	138.00	36.20	
4	Island	distribution	69.00	13.00	
5	Jerome	distribution	138.00	13.00	
6	Jerome	distribution	138.00	13.09	
7	Julion Clawson	distribution	138.00	35.00	
8	Joplin	distribution	138.00	13.00	
9	Joplin	distribution	138.00	35.00	
10	Justice	transmission	230.00	138.00	13.80
11	Karcher	distribution	138.00	13.00	
12	Kenyon	distribution	69.00	13.00	
13	Ketchum	distribution	138.00	13.00	
14	Kimberly	distribution	138.00	13.00	
15	Kinport	transmission	161.00	46.00	13.20
16	Kinport	transmission	230.00	138.00	12.47
17	Kinport	transmission	230.00	138.00	13.80
18	Kinport	transmission	345.00	230.00	13.80
19	Kramer	distribution	138.00	35.00	
20	Kramer	distribution	138.00	36.20	
21	Kuna	distribution	138.00	13.00	
22	Lake Fork	distribution	138.00	36.20	
23	Lake Fork	transmission	138.00	69.00	12.50
24	Lamb	distribution	138.00	13.00	
25	Langley Gulch- attended	transmission	230.00	138.00	13.80
26	Langley Gulch- attended	transmission	230.00		
27	Langley Gulch- attended	distribution		4.16	
28	Langley Gulch- attended	distribution	13.00	4.16	
29	Lansing	distribution	69.00	13.00	
30	Lincoln	distribution	138.00	13.09	
31	Linden	distribution	138.00	13.00	
32	Locust	distribution	138.00	36.20	
33	Locust	transmission	230.00	138.00	13.80
34	Lower Malad - attended	transmission	138.00	7.20	
35	Lower Salmon - attended	transmission	138.00	13.80	
36	Map Rock	distribution	69.00	13.00	
37	McCall	distribution	13.00	13.09	
38	McCall	distribution	138.00	36.20	
39	Meridian	distribution	138.00	13.00	
40	Micron	distribution	138.00	13.09	

SUBSTATIONS (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Micron	distribution	138.00	13.00	
2	Midpoint	transmission	230.00	138.00	13.80
3	Midpoint	transmission	345.00	230.00	13.80
4	Midpoint	transmission	500.00	345.00	
5	Midrose	distribution	138.00	13.09	
6	Milner	transmission	138.00	69.00	12.47
7	Milner	distribution	69.00	46.00	6.90
8	Milner	distribution	138.00	35.00	
9	Milner PP - attended	transmission	138.00	13.80	
10	Moonstone	distribution	138.00	35.00	
11	Mora	distribution	138.00	35.00	
12	Mora	distribution	138.00	36.20	
13	Moreland	distribution	35.00	13.00	
14	Moreland	distribution	46.00	13.00	
15	Moreland	distribution	46.00	35.00	12.47
16	Mountain Home	distribution	69.00	13.00	
17	Mountain Home Air Force Base	distribution	69.00	13.00	
18	Mountain Home Air Force Base	distribution	138.00	13.00	
19	Nampa	transmission	230.00	138.00	13.80
20	Nampa	distribution	138.00	13.00	
21	New Meadows	distribution	138.00	36.20	
22	New Plymouth	distribution	69.00	13.00	
23	Notch Butte	distribution	138.00	13.09	
24	Orchard	distribution	69.00	36.20	
25	Orchard	distribution	69.00	35.00	12.47
26	Parma	distribution	69.00	13.00	
27	Parma	distribution	69.00	35.00	
28	Paul	distribution	138.00	35.00	
29	Payette	distribution	138.00	13.00	
30	Pingree	transmission	138.00	46.00	12.50
31	Pingree	distribution	138.00	35.00	
32	Pleasant Valley	distribution	138.00	35.00	
33	Pocatello	distribution	46.00	13.00	
34	Poleline	distribution	138.00	13.09	
35	[redacted]	transmission	345.00		
36	Portneuf	distribution	138.00	35.00	
37	Portneuf	distribution	46.00	35.00	
38	Rockford	distribution	46.00	13.00	
39	Russett	distribution	138.00	13.00	
40	Sailor Creek	distribution	138.00	2.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
24	2					1
120	1					2
840	2	1				3
750	3	1				4
24	1					5
100	4					6
8	3	1				7
29	2					8
36	1					9
12	1					10
15	1					11
24	1					12
6	1					13
8	1					14
8	4					15
15	1					16
		1				17
18	1					18
180	1					19
50	3					20
12	1					21
10	1					22
10	1					23
6	1					24
10	3					25
10	1					26
12	1					27
36	2					28
23	3					29
50	3					30
22	2					31
42	2					32
36	2					33
18	1					34
						35
18	1					36
		1				37
14	2					38
18	1					39
15	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Sailor Creek	distribution	138.00	35.00	
2	Salmon	distribution	69.00	13.00	
3	Salmon	distribution	69.00	34.50	12.47
4	Salmon	distribution	69.00		12.47
5	Salmon	transmission	13.00	2.40	
6	Shoshone	distribution	46.00	13.00	
7	Shoshone	distribution	46.00	7.20	
8	Shoshone Falls - attended	transmission	46.00	2.30	
9	Shoshone Falls - attended	transmission	46.00	6.60	
10	Silver	distribution	138.00	35.00	
11	Simplot	distribution	138.00	13.00	
12	Sinker Creek	distribution	138.00	35.00	
13	Siphon	distribution	138.00	35.00	
14	South Park	distribution	46.00	13.00	
15	Star	distribution	138.00	13.09	
16	Starkey	transmission	138.00	69.00	12.47
17	State	distribution	69.00	13.00	
18	Stoddard	distribution	138.00	13.00	
19	Strike Power Plant - attended	transmission	138.00	13.80	
20	Sugar	distribution	138.00	35.00	
21	Swan Falls - attended	transmission	138.00	6.90	
22	Taber	distribution	46.00	13.00	
23	Ten Mile	distribution	138.00	13.09	
24	Terry	distribution	138.00	13.09	
25	Terry	distribution	138.00	13.00	
26	Thousand Springs - attended	transmission	46.00	7.20	
27	Thousand Springs - attended	transmission	7.00	2.40	
28	Toponis	distribution	138.00	33.00	
29	Twin Falls	distribution	138.00	13.09	
30	Twin Falls	transmission	138.00	46.00	12.98
31	Twin Falls PP - attended	transmission	138.00	7.20	
32	Twin Falls PP - attended	transmission	138.00	13.20	
33	Upper Malad - attended	transmission	45.00	7.20	
34	Upper Salmon- attended	transmission	138.00	7.20	
35	Ustick	distribution	138.00	13.00	
36	Vallivue	distribution	138.00	13.09	
37	Victory	distribution	138.00	13.00	
38	Victory	distribution	138.00	13.09	
39	Ware	distribution	69.00	13.00	
40	Weiser	distribution	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
15	1					1
10	1	3				2
10	3					3
		2				4
5	2					5
10	1					6
2	3					7
3	1					8
10	1					9
12	1					10
15	1					11
12	1					12
33	2					13
10	1					14
18	1					15
18	1					16
33	2					17
15	1					18
83	3					19
20	2					20
18	1					21
5	1					22
24	1					23
12	1					24
30	2					25
8	1					26
3	1					27
18	1					28
44	2					29
33	2					30
9	1					31
72	1					32
8	1					33
36	4					34
44	2					35
18	1					36
24	1					37
18	1					38
12	1	1				39
20	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/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	Weiser	transmission	138.00	69.00	12.47
2	Wilder	distribution	69.00	13.00	
3	Willis	distribution	138.00	13.09	
4	Wye	distribution	138.00	13.00	
5	Wye	distribution	138.00	13.09	
6	Zilog	distribution	138.00	13.09	
7					
8					
9	The above are all State of Idaho				
10					
11	Montana:				
12	Peterson	transmission	230.00	69.00	13.20
13					
14	Nevada:				
15	[redacted]	transmission	345.00	125.00	24.90
16	[redacted]	transmission	345.00	125.00	24.90
17	[redacted]	transmission	120.00	24.90	7.20
18	[redacted]	transmission	345.00		
19	[redacted]	transmission	345.00		
20	[redacted]	transmission	345.00		
21	[redacted]	transmission	345.00		
22	[redacted]	transmission	345.00		
23	Wells	transmission	138.00	69.00	13.00
24					
25	Oregon:				
26	[redacted]	transmission	500.00	24.00	
27	[redacted]	transmission	230.00	7.20	
28	[redacted]	transmission	24.00	7.20	
29	Cairo	distribution	69.00	13.00	
30	Hells Canyon - attended	transmission	230.00	13.80	
31	Hells Canyon - attended	distribution	69.00	0.50	
32	Hines	transmission	138.00	115.00	12.47
33	Malheur Butte	distribution	69.00	34.50	
34	Nyssa	distribution	69.00	13.00	
35	Ontario	distribution	138.00	13.00	
36	Ontario	transmission	138.00	69.00	12.47
37	Ontario	transmission	230.00	138.00	13.80
38	Ontario	transmission	138.00	69.00	12.98
39	Ontario	transmission	138.00	69.00	13.09
40	Ore-Ida	distribution	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
25	1					1
10	1					2
18	1					3
36	2					4
20	1					5
24	1					6
						7
						8
						9
						10
						11
30	3	1				12
						13
						14
	1					15
	1					16
	1					17
			Line Reactor	1	48	18
			Line Reactor	1	35	19
			Line Reactor	1	35	20
			Line Reactor	1	35	21
			Line Reactor	1	35	22
20	3	1				23
						24
						25
685	3	1				26
55	1					27
55	1					28
12	1					29
500	3					30
1	1					31
40	1					32
8	3	1				33
20	2					34
38	2					35
25	1	1				36
240	2					37
50	2					38
		1				39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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	Oxbow - attended	transmission	138.00	69.00	13.00
2	Oxbow - attended	transmission	230.00	13.80	
3	Oxbow - attended	transmission	230.00	138.00	13.80
4	Quartz	transmission	138.00	69.00	12.50
5	Quartz	transmission	230.00	138.00	12.98
6	Quartz	transmission	138.00	69.00	12.98
7	Vale	distribution	69.00	13.00	
8					
9	Wyoming:				
10	[redacted]	transmission	345.00	22.00	
11	[redacted]	transmission	345.00	230.00	34.50
12					
13					
14					
15					
16					
17	Transformers-distribution substations under 10,000				
18	KVA 85 unattended.				
19					
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) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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.
10	3	1				1
244	2					2
100	1					3
15	1					4
100	3	1				5
15	1					6
10	1					7
						8
						9
1122	2					10
1084	22					11
						12
						13
						14
						15
						16
						17
350						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.2 Line No.: 28 Column: a
PacifiCorp has a 59% interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway Station.

Schedule Page: 426.4 Line No.: 35 Column: a
Idaho Power has a 20.8% interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station.

Schedule Page: 426.6 Line No.: 15 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 16 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 17 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 18 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 19 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 20 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 21 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 22 Column: a
Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 26 Column: a
Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.6 Line No.: 27 Column: a
Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.6 Line No.: 28 Column: a
Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.7 Line No.: 10 Column: a
Jointly owned with PacifiCorp. Idaho Power has a 33.3% share of ownership.

Schedule Page: 426.7 Line No.: 11 Column: a
Jointly owned with PacifiCorp. Idaho Power has a 33.3% share of ownership.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/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				
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10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Managerial Expense	IDA	417420	257,667
22				
23				
24				
25				
26				
27				
28				
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ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

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STATEMENT OF INCOME FOR THE YEAR

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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$1,024,679,001	$ 969,760,290
3	Operating Expenses			
4	Operation Expenses (401)	15	565,759,812	600,989,160
5	Maintenance Expenses (402)	15	70,598,724	72,381,449
6	Depreciation Expense (403)		111,567,695	108,248,039
7	Amort. & Depl. of Utility Plant (404-405)		6,972,931	6,087,113
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Accretion Expense (411)		176,276	-
11	Regulatory Study Costs (407)			
12	Amort. of Conversion Expenses (407)			
13	Regulatory Debits/Credits (407.3 & 407.4)		-	-
14	Taxes Other Than Income Taxes (408.1)	2	28,446,377	26,932,746
15	Income Taxes - Federal (409.1)	2	(13,715,294)	(54,366,437)
16	- Other (409.1)	2	971,298	(731,383)
17	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	37,421,156	16,500,157
18	Investment Tax Credit Adj. - Net (411.4)	2	8,684,157	(1,083,203)
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23				
24	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		816,883,133	774,957,641
25				
26				
27	Net Utility Operating Income (Enter Total of line 2 less 24)		$ 207,795,868	$ 194,802,649

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 13,083,633
FUTA	$ 89,321
State Unemployment	693,464
Payroll Deduction & Loading	(13,866,418)
Total Labor Related	0
Property Taxes	24,562,103
Kilowatt-hour Tax	1,576,439
Licenses	4,798
Regulatory Commission Fees	2,042,319
Irrigation PIC	260,718
Total Taxes Other Than Income Taxes	28,446,377
Federal Income Taxes	(13,715,294)
State Income Taxes	971,298
Deferred Income Taxes	37,421,156
Investment Tax Credit Adjustment - Net	8,684,157
Total Taxes Allocated to Idaho	$ 61,807,694

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

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

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)........	$ 94,776	$ 72,492
2	Customer Accounts Receivable (Account 142)........	67,534,733	67,661,588
3	Other Accounts Receivable (Account 143)........	8,206,727	20,876,001
4	(Disclose any capital stock subscription received)		
5	Total........	$ 75,836,237	$ 88,610,081
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)...........	1,435,434	1,872,855
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts........	$ 74,400,803	$ 86,737,226
12			
13			
14	Notes Receivable - Account 141: (at 12-31-12)		
15	Directors, officers, and employees - $ -		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-12)		
19	Directors, officers, and employees - $ -		
20			

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

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

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21						
22	Bal. beginning of year	$ 1,435,434	$	$	$ 437,421	$ 1,872,855
23	Prov. for uncollectibles					
24	for year........					
25	Accounts written off........					
26	Coll. of accounts					
27	written off........					
28	Adjustments (explain)........					
29						
30						
31						
32	Balance end of year........	$ 1,435,434	$ -	$ -	$ 437,421	$ 1,872,855
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

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

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO	$ 17,335,019	$ 11,042,047	$ 27,368,817	$ 1,008,249	
4						
5						
6						
7						
8						
9						
10	Total Account 145	17,335,019	11,042,047	27,368,817	1,008,249	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc.	$ -	$ 3,539,671	$ 3,475,824	$ 63,847	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ -	$ 3,539,671	$ 3,475,824	$ 63,847	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

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

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

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

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

Line No.	Description of Property (a)	Original Cost of Related (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	**No gain to report for 2012**				
5					
6					
7					
8					
9					
10					
11					
12					
13					
14	Total gain..	$ 0		$ 0	
15					
16					
17					
18	**No loss to report for 2012**				
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss..	$ 0			$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADECCO	Management Services	$ 38,594
2	ADM ASSOCIATES INC	Energy Efficiency Services	184,830
3	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	246,868
4	BANDUCCI WOODARD SCHWARTZMAN P	Legal Services	87,486
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	613,119
6	BERGLES LAW LLC	Legal Services	86,359
7	BETHKE LAW PLLC	Legal Services	37,317
8	BRENNEMAN, JOHN	Lobbying Services	35,086
9	BROADRIDGE FINANCIAL SOLUTIONS	Management Services	44,174
10	BROWNE CONSULTING	Management Services	37,808
11	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	105,441
12	BULLARD SMITH JERNSTEDT WILSON	Legal Services	104,890
13	BURKE INCORPORATED	Management Services	175,400
14	CHARLES RIVER ASSOCIATES INCOR	Rate Case Services	270,004
15	CLEAREDGE PARTNERS INC	Management Services	75,000
16	CORPORATE OFFICE INSTALLATIONS	Office Equipment Services	70,434
17	CRAPO SMITH PLLC	Legal Services	31,549
18	D & R INTERNATIONAL, LTD	Environmental Services	22,904
19	DAVID EVANS AND ASSOCIATES	Consulting Services	73,076
20	DAVIS WRIGHT TREMAINE LLP	Legal Services	995,997
21	DC ENGINEERING, PC	Engineering Services	57,020
22	DELOITTE TAX LLP	Accounting Services	34,026
23	DESERT RESEARCH INSTITUTE	Environmental Services	57,865
24	DHI INC	Environmental Services	12,000
25	EMC CORPORATION	Environmental Services	13,500
26	ENERNOC INC	Energy Efficiency Services	117,508
27	EPICOR SOFTWARE CORPORATION	Software Consultant Services	11,950
28	ERISA LAW GROUP PA	Legal Services	15,973
29	EVANS KEANE	Legal Services	12,421
30	EVERGREEN CONSULTING GROUP, LL	Management Services	208,586
31	EXPERIS IT SERVICES US, LLC	Computer Support Services	109,280
32	FLUID MARKET STRATEGIES INC	Management Services	13,235
33	GALE ENERGY CONSULTING LLC	Management Services	36,000
34	GANNETT FLEMING INC	Management Services	44,971
35	GARTNER GROUP	Management Services	95,808
36	GIVENS PURSLEY LLP	Legal Services	86,484
37	GJORDING & FOUSER, PLLC	Legal Services	101,793
38	GLAHE & ASSOCIATES INC	Environmental Services	35,847
39	GREENBERG TRAURIG LLP	Legal Services	110,644
40	HARDESTY, REBECCA	Environmental Services	19,005
41	HYQUAL	Environmental Services	192,246
42	INTER-FLUVE, INC.	Environmental Services	85,532
43	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	162,348
44	ISS CORPORATE SERVICES, INC	Management Services	34,000
45			

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
46	JACO ENVIRONMENTAL INC	Environmental Services	$ 35,737
47	JONES AND SWARTZ PLLC	Legal Services	200,336
48	KLINE, BARTON L	Rate Case Services	13,375
49	L CONWAY CONSULTING, INC	Management Services	14,254
50	LOVINGER KAUFMANN LLP	Legal Services	222,759
51	MARKET STRATEGIES INTERNATIONA	Energy Efficiency Services	40,000
52	MCDOWELL RACKNER & GIBSON PC	Legal Services	1,447,999
53	MCMILLEN ENGINEERING, LLC	Engineering Services	22,299
54	MERITO SOLUTIONS INC	Management Services	19,975
55	MICROSOFT CORP	Management Services	13,180
56	MIRANDE, MICHAEL	Legal Services	41,233
57	NIELSEN GROUP INC, THE	Consulting Services	263,301
58	PAINE HAMBLEN LLP	Legal Services	167,000
59	PARR BROWN GEE & LOVELESS INC	Legal Services	32,733
60	PERKINS COIE LLP	Legal Services	402,012
61	PLATEAU ARCHAEOLOGICAL INVESTI	Environmental Services	29,875
62	PORTLAND ENERGY CONSERVATION,	Environmental Services	123,392
63	PROFESSIONAL TRAINING SYSTEMS	Management Services	11,348
64	PROVEN COMPLIANCE SOLUTIONS IN	Management Services	42,852
65	RIVERSIDE TECHNOLOGY INC	Management Services	46,904
66	SALLADAY, G LANCE	Legal Services	38,282
67	SCHWABE WILLIAMSON & WYATT	Legal Services	79,263
68	SHARP & SMITH INC.	Legal Services	16,142
69	STOEL RIVES LLP	Legal Services	144,986
70	STRUCTURED COMMUNICATION SYS.	Management Services	10,683
71	SULLIVAN & CROMWELL	Legal Services	157,975
72	SUNRISE ENGINEERING INC	Engineering Services	14,439
73	SYMANTEC CORPORATION	Legal Services	84,736
74	TEKSYSTEMS	Management Services	79,246
75	TETRA TECH INC	Environmental Services	78,858
76	TUERI LLC	Management Services	35,657
77	U S GEOLOGICAL SURVEY	Environmental Services	130,210
78	UNIVERSITY CORPORATION FOR	Cloud Seeding Modeling Services	193,132
79	UNIVERSITY OF ARIZONA	Weather Research & Forecast Service	61,468
80	UNIVERSITY OF IDAHO	Environmental Services	293,563
81	UNIVERSITY OF TENNESSEE	Environmental Services	51,750
82	UTILMARC INC	Management Services	12,000
83	VAN NESS FELDMAN	Rate Case Services	304,982
84	WALDNER LAW OFFICES LLC	Legal Services	11,925
85	WATERSHED SCIENCES INC	Environmental Services	30,351
86	WEATHER MODIFICATION INC	Environmental Services	343,404
87	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	66,548
88			
89			
	TOTAL		$ 10,434,539

PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	JUB ENGINEERS	Engineering Services	$ 5,170
2	INTERPRETIVE GRAPHICS SIGNS &	Management Services	5,216
3	DATA ONE LLC	Legal Services	5,717
4	RIDDELL WILLIAMS P.S.	Management Services	6,651
5	CTA ARCHITECTS	Architectural Services	7,500
6	EPOXY SYSTEMS, INC	Management Services	7,898
7	TROUT, JONES GLEDHILL FUHRMAN	Legal Services	8,118
8	RIPLEY, LARRY D	Management Services	8,175
9	RATIONAL TECHNOLOGY OF IDAHO	Management Services	9,345
10			
11			
12			
13			
14			
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45	**TOTAL**		$ 63,790

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

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

Line No.	Account (a)	Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,457	
3	(302) Franchises and Consents	22,172,205	
4	(303) Miscellaneous Intangible Plant	32,839,705	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	55,017,367	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	8,275,911	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	908,609,888	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28			
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	679,593,365	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	End of Year (g)		Line No.
					1
			$ 5,469	(301)	2
			27,768,043	(302)	3
			29,967,161	(303)	4
			57,740,673		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			10,420,185	(317)	15
			916,865,363		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			688,531,172		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 165,688,363	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,753,891,616	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	33,615,717	
49	(352) Structures and Improvements	55,493,339	
50	(353) Station Equipment	336,717,516	
51	(354) Towers and Fixtures	141,131,353	
52	(355) Poles and Fixtures	102,379,364	
53	(356) Overhead Conductors and Devices	164,369,428	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	395,522	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	834,102,239	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,288,037	
61	(361) Structures and Improvements	31,149,311	
62	(362) Station Equipment	187,486,045	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	211,409,134	
65	(365) Overhead Conductors and Devices	114,428,352	
66	(366) Underground Conduit	47,290,854	
67	(367) Underground Conductors and Devices	193,507,656	
68	(368) Line Transformers	411,389,958	
69	(369) Services	54,323,982	
70	(370) Meters	109,827,388	
71	(371) Installations on Customer Premises	2,529,769	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,181,704	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,372,812,190	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	15,434,298	
78	(390) Structures and Improvements	81,326,079	
79	(391) Office Furniture and Equipment	38,812,265	
80	(392) Transportation Equipment	58,352,942	
81	(393) Stores Equipment	1,531,151	
82	(394) Tools, Shop, and Garage Equipment	5,794,321	
83	(395) Laboratory Equipment	11,355,461	
84	(396) Power Operated Equipment	10,235,988	
85	(397) Communication Equipment	31,305,950	
86	(398) Miscellaneous Equipment	5,028,782	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	259,177,237	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	259,177,237	
91	TOTAL (Accounts 101 and 106)	4,275,000,649	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 4,275,000,649	

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	44
			$ 523,314,080		45
			2,128,710,614		46
					47
			34,144,330	(350)	48
			67,313,466	(352)	49
			350,618,551	(353)	50
			148,853,601	(354)	51
			115,480,123	(355)	52
			177,042,541	(356)	53
				(357)	54
				(358)	55
			374,559	(359)	56
				(359.1)	57
			893,827,171		58
					59
			4,640,145	(360)	60
			30,231,294	(361)	61
			183,519,214	(362)	62
				(363)	63
			212,624,115	(364)	64
			115,863,070	(365)	65
			46,149,139	(366)	66
			194,586,898	(367)	67
			433,676,693	(368)	68
			53,989,312	(369)	69
			68,386,405	(370)	70
			2,636,455	(371)	71
				(372)	72
			4,292,528	(373)	73
				(374)	74
			1,350,595,269		75
					76
			15,457,958	(389)	77
			89,805,998	(390)	78
			41,036,641	(391)	79
			62,224,617	(392)	80
			1,800,676	(393)	81
			6,200,087	(394)	82
			11,751,632	(395)	83
			11,023,650	(396)	84
			38,289,785	(397)	85
			5,391,308	(398)	86
			282,982,352		87
				(399)	88
				(399.1)	89
			282,982,352		90
			4,713,856,080		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 4,713,856,080		96

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 415,210,872	389,903,113
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	360,405,504	308,079,555
5	Large (or Industrial)(See Instr. 4) (2)	132,393,331	128,669,701
6	(444) Public Street and Highway Lighting	3,450,987	3,160,616
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	911,460,695 *	829,812,986
11	(447) Sales for Resale - Opportunity....Non-Firm Only	58,842,171	96,933,214
12	TOTAL Sales of Electricity	970,302,866	926,746,200
13	(449) Provision for Rate Refunds	(17,787,033)	(37,734,708)
14	TOTAL Revenue Net of Provision for Refunds	952,515,833	889,011,492
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,556,088	3,477,021
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	22,113,462	23,065,731
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	46,493,618	54,206,045
22			
23			
24			
25	TOTAL Other Operating Revenues	72,163,168	80,748,797
26	TOTAL Electric Operating Revenues	$ 1,024,679,001	$ 969,760,289

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

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

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

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,854,235,929	4,950,935,597	400,291	396,435	2
				3
5,684,621,245	5,259,299,071	77,437	77,038	4
2,894,339,717	2,858,414,142	112	117	5
30,944,414	28,922,261	2,044	1,557	6
				7
				8
				9
13,464,141,305 **	13,097,571,071	479,884	475,147	10
2,087,746,748	3,467,888,272	N/A	N/A	11
15,551,888,053	16,565,459,343	479,884	475,147	12
				13

* Includes $3,931,000 unbilled revenues.

** Includes -17,472,593 KWH relating to unbilled revenues.

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,346,287	$ 1,617,279
5	(501) Fuel	128,616,832	114,337,716
6	(502) Steam Expenses	7,917,399	6,631,018
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,472,009	2,128,774
10	(506) Miscellaneous Steam Power Expenses	7,996,512	9,314,506
11	(507) Rents	273,828	476,607
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	147,622,867	134,505,900
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	318,019	1,986,056
16	(511) Maintenance of Structures	728,455	880,911
17	(512) Maintenance of Boiler Plant	12,054,121	14,645,611
18	(513) Maintenance of Electric Plant	4,914,467	6,513,885
19	(514) Miscellaneous Steam Plant	4,795,520	6,206,375
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,810,582	30,232,838
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 2	170,433,450	164,738,738
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,136,805	5,147,250
45	(536) Water for Power	7,496,203	8,393,843
46	(537) Hydraulic Expenses	12,203,305	11,973,604
47	(538) Electric Expenses	1,319,589	1,540,819
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,528,231	2,948,258
49	(540) Rents	315,959	200,191
50	TOTAL Operation (Enter Total of lines 44 thru 49)	31,000,092	30,203,965

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 292,792	$ 1,687,621
54	(542) Maintenance of Structures	1,275,663	1,648,569
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,289,334	1,495,873
56	(544) Maintenance of Electric Plant	2,985,623	1,711,088
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,947,769	2,602,021
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,791,181	9,145,172
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and	39,791,273	39,349,137
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,288,599	784,824
63	(547) Fuel	23,822,329	11,159,409
64	(548) Generation Expenses	2,078,479	717,006
65	(549) Miscellaneous Other Power Generation Expenses	387,151	745,729
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	27,576,558	13,406,968
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	0
70	(552) Maintenance of Structures	199,656	171,779
71	(553) Maintenance of Generating and Electric Plant	95,543	110,002
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,435,555	1,781,101
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,730,753	2,062,882
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73	30,307,311	15,469,850
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	182,310,250	149,672,898
77	(556) System Control and Load Dispatching	2,159	1,166
78	(557) Other Expenses	(58,406,670)	37,451,652
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	123,905,739	187,125,716
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79).	364,437,773	406,683,441
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,436,111	3,183,091
84	(561) Load Dispatching	2,633,413	2,781,432
85	(562) Station Expenses	2,264,325	2,155,024
86	(563) Overhead Line Expenses	632,645	713,799
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	6,019,037	6,165,151
89	(566) Miscellaneous Transmission Expenses	168,613	294,591
90	(567) Rents	2,881,111	3,141,691
91	TOTAL Operation (Enter Total of lines 83 thru 90)	18,035,253	18,434,779
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	465,258	211,076
94	(569) Maintenance of Structures	735,819	409,517
95	(570) Maintenance of Station Equipment	3,540,656	2,846,962
96	(571) Maintenance of Overhead Lines	5,079,531	3,516,386
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	1,468	5,237
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	9,822,733	6,989,178
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	27,857,987	25,423,957
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,942,246	3,585,869

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 3,411,958	$ 3,335,858
106	(582) Station Expenses	1,120,001	1,151,687
107	(583) Overhead Line Expenses	3,510,192	2,817,997
108	(584) Underground Line Expenses	1,841,055	1,796,817
109	(585) Street Lighting and Signal System Expenses	104,460	116,145
110	(586) Meter Expenses	3,984,472	4,035,316
111	(587) Customer Installations Expenses	590,811	1,002,934
112	(588) Miscellaneous Distribution Expenses	5,381,804	5,259,071
113	(589) Rents	472,027	795,328
114	TOTAL Operation (Enter Total of lines 103 thru 113)	24,359,026	23,897,022
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	214,565	385,136
117	(591) Maintenance of Structures	0	5,501
118	(592) Maintenance of Station Equipment	3,696,105	3,119,318
119	(593) Maintenance of Overhead Lines	14,418,317	13,440,348
120	(594) Maintenance of Underground Lines	1,030,138	1,037,269
121	(595) Maintenance of Line Transformers	406,160	415,626
122	(596) Maintenance of Street Lighting and Signal Systems	541,867	527,171
123	(597) Maintenance of Meters	699,899	461,660
124	(598) Maintenance of Miscellaneous Distribution Plant	487,673	231,921
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	21,494,724	19,623,950
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	45,853,750	43,520,972
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	420,669	411,109
130	(902) Meter Reading Expenses	1,185,721	2,348,997
131	(903) Customer Records and Collection Expenses	12,704,355	12,464,340
132	(904) Uncollectible Accounts	4,234,006	4,016,095
133	(905) Miscellaneous Customer Accounts Expenses	392	241
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	18,545,143	19,240,782
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	506,730	494,702
138	(908) Customer Assistance Expenses	31,912,362	41,237,965
139	(909) Informational and Instructional Expenses	284,730	79,709
140	(910) Miscellaneous Customer Service and Informational Expenses	524,139	498,074
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 14	33,227,961	42,310,450
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	67,201,422	64,079,786
152	(921) Office Supplies and Expenses	18,085,517	15,024,667
153	(Less) (922) Administrative Expenses Transferred-Credit	(26,962,038)	(24,823,165)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 4,943,764	$ 4,701,113
156	(924) Property Insurance	3,367,186	3,071,478
157	(925) Injuries and Damages	6,828,251	5,541,210
158	(926) Employee Pensions and Benefits	58,734,533	57,109,122
159	(927) Franchise Requirements	9	0
160	(928) Regulatory Commission Expenses	4,955,643	3,046,603
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	470,811	526,939
163	(930.2) Miscellaneous General Expenses	3,845,202	3,579,030
164	(931) Rents	16,875	6,796
165	TOTAL Operation (Enter Total of lines 151 thru 164)	141,487,174	131,863,579
166	Maintenance		
167	(935) Maintenance of General Plant	4,948,750	4,327,428
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	146,435,924	136,191,007
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 636,358,536	$ 673,370,609

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

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

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

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

1	Payroll Period Ended (Date)	December 31, 2012	December 31, 2011
2	Total Regular Full-Time Employees	2,010	1,929
3	Total Part-Time and Temporary Employees	18	65
4	Total Employees	2,028	1,994