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)

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IDAHO PUBLIC
UTILITIES COMMISSION

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Idaho Power Company	End of 2011/Q4

Deloitte.

Deloitte & Touche LLP
101 South Capitol Blvd.
Suite 1700
Boise, ID 83702-7734
USA

Tel: +1 208 342 9361
Fax: +1 208 342 2199
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the balance sheet — regulatory basis of Idaho Power Company (the "Company") as of December 31, 2011, 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. These financial statements are the responsibility of the Company's management. 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 as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing 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 over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 1, 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 comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2011, 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.

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 22, 2012

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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 2011/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 Coporate 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)* 04/13/2012

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)* 04/13/2012
02 Title Coporate 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) 04/13/2012	Year/Period of Report End of 2011/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	None
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	04/13/2012	End of 2011/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	04/13/2012	End of 2011/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	04/13/2012	End of 2011/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 (3)	J. LaMont Keen	635,000
3			
4	President & Chief Financial Officer (3)	Darrel T. Anderson	383,000
5			
6	Executive Vice President, & Chief Operating Officer (3)	Dan Minor	360,000
7			
8	Senior Vice President, Corporate Responsibilty (1)	Ric Gale	240,000
9			
10	Vice President and Chief Information Officer	Dennis Gribble	212,500
11			
12	Vice President, Human Resources & Corp Services	Luci McDonald	230,000
13			
14	Senior Vice President, Finance and Treasurer (3)	Steven R. Keen	230,000
15			
16	Senior Vice President and General Counsel	Rex Blackburn	270,000
17			
18	Vice President, Chief Risk Officer	Lori Smith	207,500
19			
20	Senior Vice President, Power Supply	Lisa Grow	240,000
21			
22	Vice President, Public Affairs	Jeffrey Malmen	203,000
23			
24	Vice President, Customer Operations	Warren Kline	212,500
25			
26	Vice President Delivery Engineering & Operations	Vern Porter	195,500
27			
28	Corporate Controller & Chief Accounting Officer	Ken Petersen	180,000
29			
30	Vice President, Supply Chain	Naomi Crafton-Shankel	165,000
31			
32	Corporate Secretary	Patrick Harrington	165,000
33			
34	Vice President, Regulatory Affairs (2)	Gregory Said	165,000
35			
36	(1) Retirement 6/30/2011		
37	(2) Title/Position Change effective 1/8/2011		
38	(3) Title changes effective 1/1/2012		
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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	04/13/2012	End of 2011/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	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
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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	04/13/2012	End of 2011/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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	201109025016	09/01/2011	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2011-2012 Annua	
3				informational filing	
4				under ER09-1641	
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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	04/13/2012	End of 2011/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	04/13/2012	End of 2011/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. New transmission line - Line #528 Rockland Jct to Rockland Wind Farm 15.92 wire miles
   Additions/removals to existing lines:
   Line #221 added 7.59 wire miles.
   Line #241 extension to Neal Hot Springs added 31.32 wire miles.
   Line #426 customer owned line carries as Idaho Power removed 21.68 wire miles.
   Line #452 dual circuit tap to connect Kimberly station added 5.49 wire miles.
   Line #466 tap to Victory substateion added 5.82 wire miles.
   Line #715 added dual circuit tap Langley Gulch power plant added 16.44 wire miles.

On January 12,2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into agreements pertaining to the Boardman-to-Hemingway project.This agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 percent for PacifiCorp.

The Gateway West Transmission Project Development Agreement dated January 12, 2012 between Idaho Power and PacifiCorp outlines the terms under which the parties will jointly own, develop, design, permit and acquire rights-of-way for the Gateway West transmission project.Idaho Power's interest in the Gateway West project applies to four of ten segments involved in the project, referred to as segments 6 (which Idaho Power had previously constructed and is included only for purposes of federal permitting related to the Gateway West project), 8,9,and 10. Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement.Idaho Power's state permitting interest in its segments is 100 percent for segment 6 and 33 percentfor each of segments 8,9, and 10, with a federal permitting interest in the project of 11 percent. Segment #6 is from Borah to Midpoint, segment #8 is from Midpoint to Hemingway, Segment #9 is from Cedar Hill to Hemingway and segment #10 is from Midpoint to Cedar Hill.

6. As of December 31,2011, $300 million remained on Idaho Power's shelf registration for the issuance of first morgage bonds and debt securities. State Commission order number is the same for both issuance OPUC UF4263, IPC-E-10-10, WPSC 20005-32-10.

7. None

8. Effective 1/14/11 a 2.75% general wage increase was implemented.

9. See pages 123.20 to 123.23

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a couple of changes in the major security holders for 2011. The top ten institutional shareholders list saw 2 changes from 3rd quarter to 4th quarter. In the 4th quarter Zimmer Lucas Partners, LLC and Thompson, Siegel & Walmsley LLC replaced Artisan Partners Limited Partnership and Fisher Investments.

14. Idaho Power and its unregulated parent, IdaCorp have seperate cash management

programs. (Seperate bank accounts, liquidity facilities, short-term debt and investment programs). No money has been loaned or advanced from Idaho Power to IdaCorp through a cash management program.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	4,473,847,185	4,339,130,398
3	Construction Work in Progress (107)	200-201	591,474,855	416,949,593
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,065,322,040	4,756,079,991
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,840,782,085	1,771,654,529
6	Net Utility Plant (Enter Total of line 4 less 5)		3,224,539,955	2,984,425,462
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)		3,224,539,955	2,984,425,462
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,081,420	2,074,996
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	78,529,519	72,561,774
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)		1,852	2,511
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		25,644,107	29,306,774
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		359,418	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		106,616,316	103,946,055
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		19,178,288	73,015,293
36	Special Deposits (132-134)		0	2,802,631
37	Working Fund (135)		37,352	44,850
38	Temporary Cash Investments (136)		100,000	151,172,575
39	Notes Receivable (141)		94,776	303,143
40	Customer Accounts Receivable (142)		67,534,731	63,612,796
41	Other Accounts Receivable (143)		8,206,727	6,166,234
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,435,434	1,641,302
43	Notes Receivable from Associated Companies (145)		17,335,019	14,384,928
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	47,865,097	27,546,983
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	42,015,731	42,221,176
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	04/13/2012	End of 2011/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,474,719	3,379,745
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)		12,273,571	10,910,213
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	8,128
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		46,440,688	47,964,339
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		3,754,383	573,226
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		359,418	0
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)		267,516,230	442,464,958
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,992,504	15,869,453
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	989,194,015	761,425,884
73	Prelim. Survey and Investigation Charges (Electric) (183)		491,041	454,727
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)		630,208	564,213
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	50,880,202	55,131,472
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		13,613,712	14,524,712
82	Accumulated Deferred Income Taxes (190)	234	227,977,046	157,346,772
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,299,778,728	1,005,317,233
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,898,451,229	4,536,153,708

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	04/13/2012	end of 2011/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)		704,757,436	688,757,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	659,237,261	560,160,116
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	76,066,425	70,098,680
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)	-11,622,052	-9,567,515
16	Total Proprietary Capital (lines 2 through 15)		1,524,219,175	1,405,228,821
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,465,460,000	1,585,460,000
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	26,266,818	27,330,455
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,113,413	3,439,753
24	Total Long-Term Debt (lines 18 through 23)		1,488,613,405	1,609,350,702
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,924,461	1,881,776
29	Accumulated Provision for Pensions and Benefits (228.3)		366,648,491	268,433,659
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		33,145,395	21,210,538
32	Long-Term Portion of Derivative Instrument Liabilities		107,763	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		21,366,767	16,951,914
35	Total Other Noncurrent Liabilities (lines 26 through 34)		423,192,877	308,477,887
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		97,996,387	100,785,053
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,511,606	1,110,373
41	Customer Deposits (235)		10,799,095	1,366,711
42	Taxes Accrued (236)	262-263	4,895,725	-12,242,872
43	Interest Accrued (237)		22,038,081	24,038,150
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	04/13/2012	end of 2011/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)		1,719,933	1,689,273
48	Miscellaneous Current and Accrued Liabilities (242)		33,498,725	112,230,437
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		4,706,863	508,141
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		107,763	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		177,058,652	229,485,266
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		19,747,984	23,054,017
57	Accumulated Deferred Investment Tax Credits (255)	266-267	70,840,400	71,972,336
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	27,530,572	26,668,269
60	Other Regulatory Liabilities (254)	278	96,483,245	55,279,902
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)		933,326,224	707,009,348
64	Accum. Deferred Income Taxes-Other (283)		137,438,695	99,627,160
65	Total Deferred Credits (lines 56 through 64)		1,285,367,120	983,611,032
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,898,451,229	4,536,153,708

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	04/13/2012	End of 2011/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	1,021,585,142	1,033,052,120		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	632,997,464	622,124,906		
5	Maintenance Expenses (402)	320-323	76,104,523	71,096,344		
6	Depreciation Expense (403)	336-337	113,001,742	109,099,197		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,764,513	6,857,301		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		28,099	21,955		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	28,894,715	24,046,035		
15	Income Taxes - Federal (409.1)	262-263	-57,754,420	5,967,393		
16	- Other (409.1)	262-263	-803,160	3,057,226		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	116,679,418	83,335,948		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	99,841,847	80,939,819		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,131,934	-1,533,190		
20	(Less) Gains from Disp. of Utility Plant (411.6)		-17,392	34,607		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		398,050	444,212		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		814,535,732	842,631,754		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		207,049,410	190,420,366		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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
1,021,585,142	1,033,052,120					2
						3
632,997,464	622,124,906					4
76,104,523	71,096,344					5
113,001,742	109,099,197					6
						7
6,764,513	6,857,301					8
-22,723	-22,723					9
						10
						11
28,099	21,955					12
						13
28,894,715	24,046,035					14
-57,754,420	5,967,393					15
-803,160	3,057,226					16
116,679,418	83,335,948					17
99,841,847	80,939,819					18
-1,131,934	-1,533,190					19
-17,392	34,607					20
						21
398,050	444,212					22
						23
						24
814,535,732	842,631,754					25
207,049,410	190,420,366					26

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)		207,049,410	190,420,366		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,142,767	802,483		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		974,498	625,141		
33	Revenues From Nonutility Operations (417)		51,602	58,915		
34	(Less) Expenses of Nonutility Operations (417.1)		-18,126	657,070		
35	Nonoperating Rental Income (418)		-3,285	-6,040		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	5,967,745	7,546,332		
37	Interest and Dividend Income (419)		2,178,296	2,167,147		
38	Allowance for Other Funds Used During Construction (419.1)		25,484,071	16,551,145		
39	Miscellaneous Nonoperating Income (421)		1,428,531	1,928,056		
40	Gain on Disposition of Property (421.1)		57,199	122,735		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		35,350,554	27,888,562		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			3,355		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		718,718	440,052		
46	Life Insurance (426.2)		-757,078	93,378		
47	Penalties (426.3)		430,042	-453,479		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,167,810	1,098,260		
49	Other Deductions (426.5)		6,579,000	5,601,967		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,138,492	6,783,533		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	23,238	19,582		
53	Income Taxes-Federal (409.2)	262-263	-638,707	-2,812,996		
54	Income Taxes-Other (409.2)	262-263	-112,459	-559,924		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	511,882	1,739,465		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,327,221	1,420,220		
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)		-1,543,267	-3,034,093		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		28,755,329	24,139,122		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		79,348,955	80,490,049		
63	Amort. of Debt Disc. and Expense (428)		1,653,291	1,487,918		
64	Amortization of Loss on Reaquired Debt (428.1)		911,000	915,215		
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)		2,474,590	1,707,178		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,332,724	10,675,095		
70	Net Interest Charges (Total of lines 62 thru 69)		71,055,112	73,925,265		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		164,749,627	140,634,223		
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)		164,749,627	140,634,223		

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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	04/13/2012	End of 2011/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		558,128,446	483,599,149
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)		158,781,882	133,087,891
17	Appropriations of Retained Earnings (Acct. 436)			
18	Earnings on Hydro	215.1	-178,017	
19	Reserve for excess Earnings for Cascade Project 2010			(54,644)
20	Reserve for excess Earnings for Twin Falls & American Falls	215.1		(433,060)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-178,017	(487,704)
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			-59,704,738	(58,070,890)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-59,704,738	(58,070,890)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		657,027,573	558,128,446
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)		2,209,688	2,031,670
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		2,209,688	2,031,670
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		659,237,261	560,160,116
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		70,098,680	62,552,348
50	Equity in Earnings for Year (Credit) (Account 418.1)		5,967,745	7,546,332
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		76,066,425	70,098,680

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	164,749,627	140,634,223
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	113,001,742	109,099,197
5	Amortization of	11,025,871	12,120,185
6			
7			
8	Deferred Income Taxes (Net)	-58,819,227	75,464,788
9	Investment Tax Credit Adjustment (Net)	-726,590	-984,156
10	Net (Increase) Decrease in Receivables	-2,125,936	13,653,023
11	Net (Increase) Decrease in Inventory	-21,207,643	539,767
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	22,896,607	-5,534,463
14	Net (Increase) Decrease in Other Regulatory Assets	23,708,446	34,996,161
15	Net Increase (Decrease) in Other Regulatory Liabilities	44,336,626	11,513,932
16	(Less) Allowance for Other Funds Used During Construction	25,484,071	16,551,145
17	(Less) Undistributed Earnings from Subsidiary Companies	5,967,745	7,546,282
18	Other (provide details in footnote):	27,407,254	-41,492,468
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	292,794,961	325,912,762
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-324,431,776	-327,576,965
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	13,332,724	10,675,095
31	Other (provide details in footnote):	6,314,273	25,390,083
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-331,450,227	-312,861,977
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	04/13/2012	End of 2011/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	208,367	333,525
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):	-493,891	8,541,146
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-331,735,751	-310,987,306
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		200,000,000
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	16,000,000	50,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	16,000,000	250,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-121,063,636	-1,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-1,207,914	-3,183,141
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-59,704,738	-58,070,890
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-165,976,288	187,682,333
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-204,917,078	202,607,789
87			
88	Cash and Cash Equivalents at Beginning of Period	224,232,718	21,624,929
89			
90	Cash and Cash Equivalents at End of period	19,315,640	224,232,718

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

Amortization	Twelve Months Ended 12/31/11
Plant	6,741,790
Regulatory assets	312,521
Regulatory liabilities	(465,593)
Unamortized debt expense	2,509,015
Unamortized discount	326,339
Water rights	1,042,009
Other	559,790
	11,025,871

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

Cash paid during the period for:	
Income taxes	(1,033,185)
Interest (net of amount capitalized)	70,490,892

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

Cash Flow from Operating Activities (Other)	Twelve Months Ended 12/31/11
Pension and postretirement benefit plan expense	45,223,307
Contributions to pension and postretirement benefit plans	(22,088,331)
Gain on sale of renewable energy certificates	(398,050)
Unbilled revenues	1,523,652
Other noncash adjustments to net income	1,762,799
Accrued interest	(2,000,069)
Customer deposits	9,432,385
Other assets and liabilities	(6,048,439)
	27,407,254

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	26,330,730

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

Other Cash Flows from Plant	Twelve Months Ended 12/31/11
Sale of emission allowances and renewable energy certificates	6,314,273
	6,314,273

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

Other Investing Cash Flows	Twelve Months Ended 12/31/11
Disbursements from rabbi trust	2,491,855
Net change in notes receivable from subsidiary	(2,950,091)
Miscellaneous other investing activities	(35,655)
	(493,891)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	1,820,172			(10,086,835)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				708,772
3	Preceding Quarter/Year to Date Changes in Fair Value	1,149,129			(3,158,753)
4	Total (lines 2 and 3)	1,149,129			(2,449,981)
5	Balance of Account 219 at End of Preceding Quarter/Year	2,969,301			(12,536,816)
6	Balance of Account 219 at Beginning of Current Year	2,969,301			(12,536,816)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				934,902
8	Current Quarter/Year to Date Changes in Fair Value	(400,010)			(2,589,429)
9	Total (lines 7 and 8)	(400,010)			(1,654,527)
10	Balance of Account 219 at End of Current Quarter/Year	2,569,291			(14,191,343)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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			(8,266,663)		
2			708,772		
3			(2,009,624)		
4			(1,300,852)	140,634,223	139,333,371
5			(9,567,515)		
6			(9,567,515)		
7			934,902		
8			(2,989,439)		
9			(2,054,537)	164,749,627	162,695,090
10			(11,622,052)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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 Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Idaho Power (IPC), a wholly-owned subsidiary of IDACORP, Inc., is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated 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. IERCo is accounted for using the equity method.

Basis of Reporting
The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the FERC as set forth in its 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, the Company accounts for its investment 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 the Company's proportionate share of 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.

Management Estimates
Management makes estimates and assumptions when preparing financial statements in conformity with generally accepted accounting principles (GAAP). 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.

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, 2011 and 2010. 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. Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements 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 the 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 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 2.83 percent in 2011 and 2.84 percent in 2010.

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 2011 or 2010.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, 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 interest expense, while the equity component is included in other income. Idaho Power's weighted-average monthly AFUDC rates for 2011 and 2010 were 7.8 percent and 8.0 percent, respectively. Idaho Power's reductions to interest expense for AFUDC were $13 million for 2011 and $11 million for 2010. Other income included $25 million and $17 million of AFUDC for 2011 and 2010, 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, 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. 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.

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction over Idaho Power's Idaho service territory, Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impact currently for rate making and financial reporting. 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.

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 and Idaho Power's accumulated other comprehensive loss balance at December 31 (net of tax):

	2011	2010
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 2,569	$ 2,969
Senior Management Security Plan	(14,191)	(12,537)
Total	$ (11,622)	$ (9,568)

Other Accounting Policies
Debt discount, expense, and premium are deferred and are being amortized over the terms of the respective debt issues.

New Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued the following accounting guidance, which is effective for years beginning after December 15, 2011:

- In May 2011, the FASB issued guidance to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between generally accepted accounting principles in the United States and International Financial Reporting Standards. The guidance changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. Idaho Power is currently assessing the impact of the guidance but do not believe that the adoption of this guidance will have a material effect on their consolidated financial statements.

2. INCOME TAXES:

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

	2011	2010
	(thousands of dollars)	
Federal income tax expense at 35% statutory rate	$ 42,116	$ 51,614
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,089)	(2,641)
AFUDC	(13,586)	(9,529)
Capitalized interest	6,465	3,674
Investment tax credits	(3,355)	(3,378)
Removal costs	(2,244)	(2,850)
Capitalized overhead costs	(5,950)	(3,500)
Capitalized repair costs	(14,000)	(10,500)
Tax method change - uniform capitalization	-	(65,333)
Tax method change – capitalized repairs	-	(44,466)
Uncertain tax positions - established	-	74,436
Uncertain tax positions – settled	(63,138)	(1,138)
State income taxes, net of federal benefit	1,846	5,074
Depreciation	14,100	13,138
Other, net	(4,583)	2,233
Total income tax (benefit) expense	$ (44,418)	$ 6,834
Effective tax rate	(36.91%)	4.6 %

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

	2011	2010
	(thousands of dollars)	
Income taxes currently payable:		
Federal	$ 7,832	$ (62,068)
State	7,296	(5,579)
Total	15,128	(67,647)
Income taxes deferred:		
Federal	22,942	6,752
State	(6,920)	(4,036)
Total	16,022	2,716
Uncertain tax positions:		
Federal	(66,225)	65,222
State	(8,211)	8,076
Total	(74,436)	73,298
Investment tax credits:		
Deferred	2,223	1,844
Restored	(3,355)	(3,377)
Total	(1,132)	(1,533)
Total income tax (benefit) expense	$ (44,418)	$ 6,834

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

	2011	2010
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 45,473	$ 46,199
Advances for construction	5,118	7,061
Deferred compensation	22,067	21,045
Advanced payments	12,958	8,292
Power cost adjustments	1,711	-
Tax credits	8,547	6,461
Revenue sharing	10,594	-
Retirement benefits	122,445	88,827
Other	3,758	4,422
Total	232,671	182,307
Deferred tax liabilities:		
Property, plant and equipment	333,335	284,794
Regulatory assets	599,992	422,216
Conservation programs	3,464	7,611
Power cost adjustments	-	11,833
Retirement benefits	122,712	93,997
Other	15,956	11,146
Total	1,075,459	831,597
Net deferred tax liabilities	$ 842,788	$ 649,290

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.

Tax Credits Carryforwards

As of December 31, 2011, Idaho Power had $8.5 million of Idaho investment tax credit carryforward. Idaho investment tax credit expires from 2023 to 2025.

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):

	2011	2010
Balance at January 1,	$ 74,436	$ 1,138
Additions for tax positions of the current year	—	2,822
Additions for tax positions of prior years	—	71,614
Reductions for tax positions of prior years	(66,379)	(1,138)
Settlements with taxing authorities	(8,057)	—
Balance at December 31,	$ —	$ 74,436

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Idaho Power recognized a net reduction in interest expense of $0.2 million in 2011and interest expense of $0.2 million in 2010. Accrued interest was was zero as of December 31, 2011and $0.2 million as of December 31, 2010. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years are 2011 for federal and 2008-2011 for Idaho. In May 2009, IDACORP and Idaho Power formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for their 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.

With the resolution of Idaho Power's capitalized repairs and uniform capitalization tax accounting methods examinations (discussed below), the 2009 tax year is now closed for federal purposes. In 2011, the IRS also completed its examination of IDACORP's 2010 tax year with no unresolved income tax issues. Idaho Power believes there are no remaining material tax uncertainties for 2011 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

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

For the year ended December 31, 2010, Idaho Power recorded a $44.5 million tax benefit related to the filed deduction for the cumulative method change adjustment and an additional $11.7 million tax benefit for the annual deduction estimate included in its 2010 income tax provision. As of December 31, 2010, Idaho Power had a current uncertain tax position liability of $14.7 million related to this method.

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. Idaho Power considers the capitalized repairs method effectively settled and believes that 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.

For the year ended December 31, 2011, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $15.6 million tax benefit. 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 prescribed regulatory accounting treatment requires immediate income recognition 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 $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2011, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $6.6 million tax benefit. 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. The prescribed regulatory accounting treatment for this method is the same as discussed earlier for the capitalized repairs method.

Cash Impacts of Tax Method Changes

In 2011, Idaho Power paid previously accrued income tax liabilities of $8.1 million, related to the capitalized repairs examination agreement. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010.

In 2010, Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $42 million. The majority of this cash benefit was realized through reductions to cash payments that would have otherwise been owed to taxing authorities for the 2009 tax year and a federal refund of $24 million received in 2010. Additionally, approximately $6 million of state cash benefits were realized through reduced tax payments for the 2010 year.

The capitalized repairs and uniform capitalization method changes produced an income statement tax benefit of $44.5 million and $65.3 million, respectively, in 2010 prior to the accrual for uncertain tax positions. A portion of this earnings benefit related to previously deferred income tax expense being flowed through the income statement, which does not deliver any cash benefits. In addition, federal tax credits of $17 million previously recognized were restored due to the reduction of 2009 taxable income by the two method changes. The restored credits were a reduction to cash received in 2010, but will be available to deliver cash benefits in future periods.

3. REGULATORY MATTERS

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is reasonably expected 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, 2011	2010
Regulatory Assets:					
Income taxes		$ —	$ 603,772	$ 603,772	$ 429,457
Unfunded postretirement benefits(2)		—	262,503	262,503	182,742
Pension expense deferrals(3)	2012-2015	38,976	19,068	58,044	63,833
Energy efficiency program costs(3)		15,956	—	15,956	19,467
Power supply costs(3)	Varies	8,490	—	8,490	29,753
Fixed cost adjustment(3)	Varies	14,457	—	14,457	12,340
Asset retirement obligations(4)		—	15,557	15,557	15,372
Mark-to-market liabilities(5)		—	4,707	4,707	2,278
Other	2012-2021	993	2,868	3,861	6,184
Total		$ 78,872	$ 908,475	$ 987,347	$ 761,426
Regulatory Liabilities:					
Income taxes		$ —	$ 49,253	$ 49,253	$ 53,440
Removal costs(4)		—	163,173	163,173	157,642
Investment tax credits		—	70,841	70,841	71,972
Deferred revenue-AFUDC (3)		21,034	12,111	33,145	21,211
Power supply costs (3)	Varies	13,121	—	13,121	—
2010 Settlement agreement sharing mechanism(3)	2013	27,099	—	27,099	—
Mark-to-market assets(5)		—	3,754	3,754	573
Other	2012	1,250	159	1,409	8,508
Total		$ 62,504	$ 299,291	$ 361,795	$ 313,346

(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 below.

(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, and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments are based on (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 the years ended December 31, 2011and 2010.

Effective Date	$ Change (millions)	Notes
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.
June 1, 2010	$ (146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below in "January 2010 and December 2011 Idaho Settlement Agreements." Concurrent with the PCA rate decrease, the IPUC authorized an $88.7 million increase in base rates, $63.7 million of which was related to power supply costs.

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 the years ended December 31, 2011 and 2010 were as follows:

Year and Mechanism	APCU or PCAM Adjustment
2011 PCAM	Actual net power supply costs were below the deadband, resulting in a $1.5 million deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
2010 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2010 APCU	A rate increase of $2.6 million annually took effect June 1, 2010.

Idaho Regulatory Matters

2011 Idaho General Rate Case and Settlement: On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. The filing was based on a 2011 test year and requested approximately $82.6 million in additional Idaho jurisdiction annual revenues in base rates, a 9.9 percent overall average rate increase for Idaho customers.

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. On December 30, 2011, the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 30, 2011 order provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional 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 jurisdictional base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

The settlement stipulation approved by the order also addressed Idaho Power's calculation of the LCAR to be applied in Idaho Power's PCA mechanism. The LCAR adjusts power supply cost recovery within the Idaho PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provides 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.

In its general rate case application, Idaho Power had requested approval of the current fixed cost adjustment (FCA) mechanism pilot program, described below, as a permanent rate mechanism for residential and small commercial class customers. Neither the December 30, 2011 order nor the settlement stipulation resolves whether the fixed cost adjustment pilot program should be made permanent.

Neither the order nor the settlement stipulation imposes a moratorium on Idaho Power's filing a general revenue requirement case at a future date.

January 2010 and December 2011 Idaho Settlement Agreements: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power's customers, the IPUC Staff, and others. 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. This provision anticipated a significant reduction in PCA rates for the 2010-2011 PCA year;
- 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.

On April 15, 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. On May 28, 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. The net effect of these two rate adjustments was an overall decrease in customer rates of $58.2 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-jurisdictional earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

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 and filed with the IPUC on December 12, 2011. The settlement stipulation provides 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 that $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 jurisdictional earnings exceeding a 10.0 percent, but less than a 10.5 percent, Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; 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 and 25 percent to Idaho Power.

The 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 settlement stipulation provided that Idaho Power would also allocate to customers 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded in 2011 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.

Idaho Fixed Cost Adjustment: The FCA began as a pilot program for Idaho Power's Idaho residential and small general service customers, running 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. On April 29, 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent for residential and small general service customer classes effective January 1, 2012; a determination from the IPUC is pending.

The following table summarizes recent FCA rate adjustments:

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

2008	June 1, 2009-May 31, 2010	2.7

As of December 31, 2011, the deferral balance for the FCA was $14.5 million.

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, 2011, Idaho Power's deferral balance was $58.0 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions.

In May 2010, the IPUC approved Idaho Power's request to increase rates to allow recovery of Idaho Power's 2009 cash contribution to its defined benefit pension plan, which contribution was made in September 2010. Idaho Power's application sought approval of $5.4 million in pension cost recovery over a one-year period to allow recovery contemporaneous with Idaho Power's expected cash contributions to the plan.

In September 2010, Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount, to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On October 1, 2010, Idaho Power filed an application with the IPUC requesting an order accepting Idaho Power's 2011 retirement benefits package, but not requesting recovery through rates of additional pension plan contributions. On April 28, 2011, the IPUC issued an order accepting Idaho Power's 2011 retirement benefits package.

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.

Transmission Revenue Shortfall Filing: On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund to transmission customers transmission revenues that Idaho Power had received starting in 2006. This refund ultimately resulted in under-recovery of transmission costs by Idaho Power, and in October 2009 the IPUC authorized Idaho Power to record an Idaho-jurisdiction regulatory asset for the transmission revenue shortfall, for future recovery in customer rates. At December 31, 2011, the transmission revenue shortfall was $2.1 million. The IPUC ordered that Idaho Power advise the IPUC when the FERC has issued its order on rehearing, following which Idaho Power may request a commencement date for the amortization period for the regulatory asset. On December 7, 2011, the FERC issued an order denying rehearing. Accordingly, on February 15, 2012, Idaho Power submitted an application to the IPUC seeking to include the $2.1 million transmission revenue shortfall in customer rates, recoverable over a three-year period beginning June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

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.

On August 18, 2011, the IPUC issued an order approving Idaho Power's March 2011 application requesting that the IPUC designate Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. Idaho Power's 2010 expenditures for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions totaled $44.2 million. On March 16, 2010, Idaho Power filed an application with the IPUC requesting an order designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred expenses. On November 16, 2010, the IPUC issued an order designating all $50.7 million of energy efficiency expenditures as prudently incurred and approved for ratemaking purposes.

On October 22, 2010, Idaho Power filed an application with the IPUC requesting acceptance of the company's demand-side resources (DSR) business model, which included a request for authorization to (a) move demand response incentive payments out of the energy efficiency rider and into the Idaho PCA on a prospective basis beginning on June 1, 2011, and thus subject to a true-up under the PCA mechanism; (b) establish a regulatory asset for the direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers, beginning January 1, 2011, so that Idaho Power may capitalize the direct incentive payments associated with the program, include the costs associated with the program incentive payments in its rate base, and thus earn a rate of return on a portion of its DSR activities; and (c) change the carrying charge on the existing energy efficiency rider balancing account (from the then-current interest rate of 1.0 percent to Idaho Power's authorized rate of return). On April 1, 2011, the IPUC issued an order stating that certain issues raised in the application are more properly considered in a general rate case proceeding. However, the IPUC noted in its order that Idaho Power's energy efficiency rider balance includes approximately $10 million in expenditures that have been previously approved by the IPUC for recovery, and thus authorized recovery of $10 million of the rider balance in Idaho Power's Idaho PCA rates, beginning June 1, 2011. In that order, the IPUC did not approve a change to the energy efficiency rider balance carrying charge.

On May 17, 2011, the IPUC issued an order stating that it will allow Idaho Power to account for specified direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers as a regulatory asset beginning January 1, 2011, but with an amortization period to be determined later by the IPUC.

In its June 1, 2011 general rate case filing, Idaho Power requested authorization to treat demand response incentive payments as power supply costs and establish a base or "normal" level of cost recovery of approximately $11.3 million for those demand response incentive payments in rates. The Idaho general rate case settlement stipulation approved by the IPUC in December 2011 provides that the $11.3 million of base level demand response incentive payments would be tracked as part of the Idaho PCA mechanism. 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.

Langley Gulch Power Plant Ratemaking Treatment: On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power's rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred.

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, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues which, if approved, would result in a 14.7 percent overall average rate increase for customers in the Oregon jurisdiction. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves 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 settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2009 Oregon General Rate Case: On February 24, 2010, the OPUC approved a $5 million, or 15.4 percent, increase in base rates in the Oregon jurisdiction. The new rates were effective March 1, 2010, and were based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. Idaho Power's previously authorized rate of return in Oregon was 7.83 percent.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. On February 12, 2009, the IPUC approved Idaho Power's application requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC subsequently clarified that Idaho Power can expect to include in rate base the Idaho portion of prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million, plus certain costs that the company could not quantify with precision at the time of the application. The IPUC also clarified, as requested by Idaho Power, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout Idaho Power's service territory will eliminate or wholly offset the increase in Idaho Power's revenue requirement caused by the authorized depreciation period.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI through the then-current date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded in 2011and 2010 was $10.6 million and $10.6 million respectively. On May 28, 2010, the IPUC approved Idaho Power's March 15, 2010 application requesting authorization to implement a $2.4 million base rate increase for identified customer classes to recover costs relating to the AMI project, with the rate increase effective June 1, 2010.

In the Oregon jurisdiction, the OPUC approved accelerated depreciation and recovery of existing meters located in Oregon over an 18-month period beginning January 2009. The approval increased both rates and depreciation expense by $0.8 million in 2009 and $0.4 million in 2010.

Idaho Power has completed the installation of substantially all smart meters associated with the AMI project. On February 15, 2012, Idaho Power filed an application with the IPUC requesting authority to decrease its Idaho-jurisdiction base rates by $10.6 million annually due to the removal of accelerated depreciation expense associated with non-AMI metering equipment. As of the date of this report, a determination and order from the IPUC is pending.

Depreciation Filings

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 net salvage percentages and service life estimates for all plant assets, and adjust Idaho-jurisdictional base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdictional base rates, with new rates effective June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Federal Open Access Transmission Tariff (OATT) Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's three most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per KW-year)*
October 1, 2009 to September 30, 2010	$ 15.83
October 1, 2010 to September 30, 2011	$ 19.60
October 1, 2011 to September 30, 2012	$ 19.79

* In September 2010, Idaho Power made corrections to its OATT rates for the period beginning October 1, 2007 through September 30, 2010, which resulted in the issuance of a $0.5 million refund to transmission customers.

4. LONG-TERM DEBT

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

	2011	2010
First mortgage bonds:		
6.60% Series due 2011	$ —	$ 120,000
4.75% Series due 2012	100,000	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
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
Total first mortgage bonds	1,295,000	1,415,000
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	6,382	7,446
Unamortized premium/discount - net	(3,113)	(3,440)
Total Idaho Power outstanding(2)	$ 1,488,614	$ 1,609,351

(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, 2011 to $1.461 billion.

(2) At December 31, 2011 and 2010, the overall effective cost of Idaho Power's outstanding debt was 5.43 percent and 5.53 percent, respectively.

At December 31, 2011, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

2012	2013	2014	2015	2016	Thereafter
$ 101,064	$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,316,407

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. As of December 31, 2011, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

On March 2, 2011, Idaho Power repaid at maturity $120 million of first mortgage bonds using proceeds from first mortgage bonds issued in August 2010.

On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement.

Mortgage: As of December 31, 2011, 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 $1.3 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 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

On October 26, 2011, Idaho Power entered into a amended and restated credit agreement, which amended and restated the existing $300 million credit facility. The new credit facility 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, respectively, subject to certain conditions. The credit facility matures on October 26, 2016, although Idaho Power has the right to request up to two one-year extensions of the credit agreement, in each case subject to certain conditions.

The interest rates for any borrowings under the facility is based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on Idaho Power's, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreement. The company pays a facility fee on the commitment based on the company's credit rating for senior unsecured long-term debt securities.

At December 31, 2011, no amounts were outstanding under Idaho Power's facility. At December 31, 2011, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings of commercial paper were as follows at December 31 (in thousands of dollars):

	Idaho Power	
	2011	**2010**
Commercial paper balances:		
At the end of year	$ —	$ —
Average during the year	$ —	$ 348

6. COMMON STOCK

Idaho Power Common Stock

In 2011 and 2010, IDACORP contributed $16 million and $50 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 their respective credit facilities or Idaho Power's Revised Code of Conduct. At December 31, 2011, the leverage ratio for Idaho Power was 49 percent. Based on these restrictions, Idaho Power's dividends are limited to $723 million at December 31, 2011. 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 the company from any material subsidiary.

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. 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. Idaho Power has no preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act, but if conservatively interpreted could limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

Idaho Power must obtain approval of the OPUC before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

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, 2011, the maximum number of shares available under the LTICP and RSP were 1,503,861 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 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 meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued and paid out only on shares that eventually vest.

The performance awards are based on two 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 market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

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, 2011	329,501	$26.35
Shares granted	135,016	30.30
Shares forfeited	(11,451)	27.32
Shares vested	(115,883)	25.28
Nonvested shares at December 31, 2011	337,183	$26.40

The total fair value of shares vested during the years ended December 31, 2011 and 2010, was $4.1 million and $3.3 million, respectively. At December 31, 2011, Idaho Power had $4 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.68 years. Idaho Power uses IDACORP's original issue and/or treasury shares for these awards.

In 2011, a total of 11,920 shares were awarded to directors at a grant date fair value of $37.74 per share. Directors elected to defer receipt of 5,960 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, 2011, all compensation costs have been recognized. Idaho Power uses IDACORP's uses original issue and/or treasury shares to satisfy exercised options.

Idaho Power's stock option transactions are summarized below.

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2010	202,634	$ 38.05	1.13	$ 314
Exercised	(90,945)	35.54		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	9,456	$ 33.67	1.58	$ 83
Vested and exercisable at December 31, 2011	9,456	$ 33.67	1.58	$ 83

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

	2011	2010
Fair value of options vested	$ —	$ 96
Intrinsic value of options exercised	535	1,475
Cash received from exercises	3,838	5,394
Tax benefits realized from exercises	209	577

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):

	2011	2010
Compensation cost	$ 4,082	$ 3,489
Income tax benefit	1,596	1,364

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2011, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2012	2013	2014	2015	2016	Thereafter
Cogeneration and power production	$ 165,693	$ 196,261	$ 209,295	$ 214,960	$ 218,220	$ 3,687,810
Power and transmission rights	10,772	4,243	3,188	2,210	1,879	4,401

Fuel	79,138	64,852	66,309	22,661	8,909	98,212

As of December 31, 2011, Idaho Power had signed agreements to purchase energy from 119 CSPP facilities with contracts ranging from one to 35 years. Ninety-six of these facilities, with a combined nameplate capacity of 606 MW, were on-line at the end of 2011; the other 23 facilities under contract, with a combined nameplate capacity of 383 MW, are projected to come on-line by year end 2014. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2011, Idaho Power purchased 1,495,108 megawatt-hours (MWh) from these projects at a cost of $90 million, resulting in a blended price of $60.36 per MWh. Idaho Power purchased 910,429 MWh at a cost of $55 million in 2010.

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

	2012	2013	2014	2015	2016	Thereafter
Operating leases	$ 2,005	$ 2,875	$ 2,768	$ 2,199	$ 1,203	$ 15,711
Equipment, maintenance, and service agreements	38,553	15,271	6,169	4,897	3,700	8,254
FERC and other industry-related fees	12,391	12,031	9,745	9,745	6,596	32,981

IPC's expense for operating leases was approximately $5.2 million in 2011 and $3.3 million in 2010.

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 $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2011, the value of the reclamation trust fund totaled $80 million. 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. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2011, 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 their respective consolidated balance sheets 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. Idaho Power intends to vigorously protect and defend their interests and pursue their rights. However, 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 accruals for legal proceedings are not material to their financial statements as a whole; however, future accruals could be material in a given period. Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. 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 certain of those matters described in this report for which Idaho Power has determined a loss contingency may, in the future, be at least reasonably possible, Idaho Power has stated that they are unable to estimate the possible loss or a range of possible loss that may result from those matters. Depending on a range of factors, such as the complexity of the facts, the unique nature of the legal theories, the pace of discovery, the timing of court decisions, and the adverse party's willingness to negotiate towards a resolution, it may be months or years after the filing of a case before Idaho Power may be in a position to estimate the possible loss or range of possible loss for those matters.

Given the substantial or indeterminate amounts sought in certain of the matters described below, and the inherent unpredictability of such matters, an adverse outcome in certain of these matters could have a material adverse effect on Idaho Power's financial condition, results of operations, or cash flows in particular quarterly or annual periods. For matters that affect Idaho Power's operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery of incurred costs through the ratemaking process.

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 (Ninth Circuit). Except as to the matters described below under "Pacific Northwest Refund," Idaho Power and IDACORP Energy (IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and predict that these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. During that period, Idaho Power or IE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in *Port of Seattle, Washington v. FERC*, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales originating in the Pacific Northwest to the California Department of Water Resources (CDWR) in the scope of the proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On October 3, 2011, the FERC issued its order on remand. The FERC ordered that the record be re-opened to permit parties seeking refunds to submit seller-specific evidence in support of their claims for sales made during the period confined to December 25, 2000 through June 20, 2001. The seller-specific claims must show that a seller engaged in unlawful market activity with a causal connection to have directly affected the negotiation of the specific contract or contracts to which the seller was a party. Neither claims of general dysfunction in the California markets nor in the Pacific Northwest market will be sufficient to support claims. While directing a trial-type hearing, the FERC also directed that the hearings be held in abeyance so that the matter may be presented to a settlement judge. On November 2, 2011, each of the City of Seattle, Washington, the City of Tacoma, Washington, the Port of Seattle, and the California Parties (consisting of the California Attorney General and the California Public Utilities Commission) filed requests for rehearing, seeking to expand the scope of the October 3, 2011 order. The designated settlement judge has met with the parties and convened a settlement conference to establish settlement procedures. The FERC's Chief Administrative Law Judge memorialized certain settlement procedures to which the parties agreed in an order issued on November 23, 2011.

IE and Idaho Power intend to continue to defend their positions in the Pacific Northwest refund proceedings vigorously. As of the date of this report, it is difficult to predict the outcome of this matter. Idaho Power does not believe that claims conforming to the requirements of the FERC's October 3, 2011 order have been submitted, and the FERC's order remains subject to rehearing and reconsideration. Idaho Power and IE are unable to predict when and how the FERC will act on the rehearing requests, which contracts would be subject to refunds, whether the FERC will order refunds, or how the refunds would be calculated. As a result of these factors, as of the date of this report Idaho Power and IE are unable to estimate the reasonably possible loss or range of losses that Idaho Power or IE could incur as a result of this matter. However, based on the status of settlement discussions with one party to the proceedings, for that portion of the matter Idaho Power reserved for a contingent liability an amount immaterial to Idaho Power's financial statements in the fourth quarter of 2011.

EPA Notice of Violation - Boardman

In September 2010, the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation to Portland General Electric Company (PGE), alleging that PGE had violated the New Source Performance Standards (NSPS) and operating permit requirements under the Clean Air Act (CAA) as a result of modifications made to the Boardman coal-fired plant in 1998 and 2004. PGE is the operator of the Boardman plant, and Idaho Power has a 10 percent ownership interest in the plant. The Notice of Violation states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but it does not impose any penalties or specify the amount of any proposed penalties with respect to the alleged violations. It is difficult to meaningfully predict the eventual outcome of this matter given the complexity of the environmental statutes and claims cited in the Notice of Violation and the matters at issue, the unspecified nature of the penalty or other remedy sought, and the absence of factual information given the early stage of the proceedings. As of the date of this report, based on available information and the status of this matter, Idaho Power is unable to estimate the reasonably possible loss or range of losses that Idaho Power could incur as a result of this matter. However, PGE, the plant operator, has stated that based on its understanding of the penalties authorized under the CAA, the maximum penalty that could be imposed for the alleged violations is approximately $60 million, with Idaho Power's share of any such penalty being limited to 10 percent of the amount ultimately assessed, if any.

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 1970's and early 1980's 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 on March 25, 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, Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Legal Proceedings

From time to time Idaho Power is party to legal claims, actions, and proceedings in addition to those discussed above. However, as of the date of this report the company believes that resolution of these matters will not have a material adverse effect on the consolidated financial positions, results of operations, or cash flows.

10. BENEFIT PLANS

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. Idaho Power's policy is to fund, with an independent corporate trustee, 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 2011 and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2011 and 2010, approximately \$41.2 million and \$46.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		SMSP	
	2011	**2010**	**2011**	**2010**
Change in benefit obligation:				
Benefit obligation at January 1	$ 569,934	$ 506,744	$ 59,126	$ 52,719
Service cost	20,478	17,671	1,950	1,541
Interest cost	30,322	29,119	3,094	3,004
Actuarial loss	55,535	35,909	4,251	5,186
Benefits paid	(20,830)	(19,509)	(3,378)	(3,324)
Benefit obligation at December 31	655,439	569,934	65,043	59,126
Change in plan assets:				
Fair value at January 1	397,003	313,474	—	—
Actual return on plan assets	(4,592)	43,038	—	—
Employer contributions	18,500	60,000	—	—
Benefits paid	(20,830)	(19,509)	—	—
Fair value at December 31	390,081	397,003	—	—
Funded status at end of year	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,496)	$ (3,289)
Noncurrent liabilities	(265,358)	(172,931)	(61,547)	(55,837)
Net amount recognized	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 245,632	$ 161,855	$ 21,799	$ 18,840
Prior service cost	1,335	1,855	1,502	1,744
Subtotal	246,967	163,710	23,301	20,584
Less amount recorded as regulatory asset	(246,967)	(163,710)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 23,301	$ 20,584
Accumulated benefit obligation	$ 549,503	$ 482,448	$ 59,836	$ 54,213

The following table shows the components of net periodic benefit cost for these plans (in thousands of dollars):

	Pension Plan		SMSP	
	2011	2010	2011	2010
Service cost	$ 20,478	$ 17,671	$ 1,950	$ 1,541
Interest cost	30,322	29,119	3,094	3,004
Expected return on assets	(32,322)	(26,463)	—	—
Amortization of net loss	8,673	7,675	1,293	931
Amortization of prior service cost	519	650	242	233
Net periodic pension cost	27,670	28,652	6,579	5,709
Adjustment to cost recognized due to the effects of regulation(1)	6,662	(24,104)	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,332	$ 4,548	$ 6,579	$ 5,709

(1) Net periodic benefit costs for the pension plan are recognized based on the authorization of each regulatory jurisdiction Idaho Power operates within. 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 2011 Idaho pension rate order, which increased Idaho-jurisdiction recovery to $17.1 million annually, effective June 1, 2011, and also for information on Idaho Power's sharing mechanism, which resulted in additional Idaho pension amortization of $20.3 million in 2011.

In 2012, Idaho Power expects to recognize as components of net periodic benefit cost $15.9 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2011, relating to the pension and SMSP plans. This amount consists of $13.9 million of amortization of net loss and $0.3 million of amortization of prior service cost for the pension plan, and $1.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2012	2013	2014	2015	2016	2017-2021
Pension Plan	$ 22,360	$ 24,001	$ 25,684	$ 27,597	$ 29,761	$ 186,450
SMSP	3,578	3,707	3,899	4,063	4,084	22,797

As of December 31, 2011, Idaho Power's minimum required contributions to the defined benefit pension plan are estimated to be approximately $34 million in 2012, $44 million in 2013, $44 million in 2014, $42 million in 2015, and $42 million in 2016. Idaho Power may elect to make contributions 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 active 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):

		2011		2010
Change in accumulated benefit obligation:				
Benefit obligation at January 1	$	68,048	$	62,647
Service cost		1,323		1,276
Interest cost		3,434		3,578
Actuarial loss		(2,850)		3,291
Benefits paid(1)		(2,968)		(3,373)
Plan amendments		(318)		629
Benefit obligation at December 31		66,669		68,048
Change in plan assets:				
Fair value of plan assets at January 1		33,176		30,892
Actual return on plan assets		1,065		3,381
Employer contributions		628		2,276
Benefits paid(1)		(2,968)		(3,373)
Fair value of plan assets at December 31		31,901		33,176
Funded status at end of year (included in noncurrent liabilities)	$	(34,768)	$	(34,872)

(1) Benefits paid are net of $3,405 and $2,971 of plan participant contributions, and $444 and $415 of Medicare Part D subsidy receipts for 2011 and 2010, respectively.

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

		2011		2010
Net loss	$	14,112	$	15,963
Prior service credit		(323)		(426)
Transition obligation		2,040		4,080
Subtotal		15,829		19,617
Less amount recognized in regulatory assets		(15,536)		(19,032)
Less amount included in deferred tax assets		(293)		(585)
Net amount recognized in accumulated other comprehensive income	$	—	$	—

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

		2011		2010
Service cost	$	1,323	$	1,276
Interest cost		3,434		3,578
Expected return on plan assets		(2,641)		(2,503)
Amortization of net loss		577		562
Amortization of prior service cost		(421)		(482)
Amortization of unrecognized transition obligation		2,040		2,040
Net periodic postretirement benefit cost	$	4,312	$	4,471

In 2012, Idaho Power expects to recognize as components of net periodic benefit cost $2.2 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2011 relating to the postretirement benefit plan. This amount consists of $(0.4) million of prior service cost, $0.6 million of net loss, and $2.0 million of transition obligation.

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, 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):

	2012	2013	2014	2015	2016	2017-2021
Expected benefit payments	$ 4,176	$ 4,261	$ 4,415	$ 4,543	$ 4,620	$ 23,849
Expected Medicare Part D subsidy receipts	478	524	563	612	671	4,441

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	
	2011	2010	2011	2010	2011	2010
Discount rate	4.90%	5.40%	5.10%	5.40%	5.05%	5.40%
Rate of compensation increase(1)	4.35%	4.50%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	7.0%	7.5%
Dental trend rate	—	—	—	—	5%	5%
Measurement date	12/31/2011	12/31/2010	12/31/2011	12/31/2010	12/31/2011	12/31/2010

(1) The 2011 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 the fortieth year of service and beyond.

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

	Pension Plan		SMSP		Postretirement Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	5.40%	5.90%	5.40%	5.90%	5.40%	5.90%
Expected long-term rate of return on assets	8.25%	8.25%	—	—	8.25%	8.25%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	7.0%	7.5%
Dental trend rate	—	—	—	—	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 7.0 percent and 7.5 percent in 2011 and 2010, respectively. The assumed health care cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in both 2011 and 2010. The assumed dental cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. A one percentage point change in the assumed health care cost trend rate would have the following effects at

December 31, 2011 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 342	$ (255)
Effect on accumulated postretirement benefit obligation	2,939	(2,300)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2011 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation 31-Dec-11
Debt securities	24%	25%
Equity securities	54%	54%
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 following hierarchy:

- Level 1, which refers to securities valued using quoted prices from active markets for identical assets;
- Level 2, which refers to securities not traded on an active market but for which observable market inputs are readily available; and
- Level 3, which refers to securities valued based on significant unobservable inputs.

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. The following table sets forth by level within the fair value hierarchy a summary of the plans' investments measured at fair value on a recurring basis at December 31, 2011 (in thousands of dollars):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (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(2)	$ —	$ 31,901	$ —	$ 31,901
Assets at December 31, 2010				
Pension assets:				
Cash and cash equivalents	$ 16,837	$ —	$ —	$ 16,837
Short-term bonds(1)	—	30,241	—	30,241
Core bonds(1)	—	43,156	—	43,156
Equity Securities: Large-Cap	58,961	—	—	58,961
Equity Securities: Mid-Cap	17,775	14,261	—	32,036
Equity Securities: Small-Cap	35,278	—	—	35,278
Equity Securities: Micro-Cap	17,422	—	—	17,422
Equity Securities: International	32,655	33,874	—	66,529
Equity Securities: Emerging Markets	2,199	18,241	—	20,440
Real estate	—	—	22,069	22,069
Private market investments	—	—	29,932	29,932
Commodities funds	3,406	20,696	—	24,102

Total pension assets	$ 184,533	$ 160,469	$ 52,001	$ 397,003
Postretirement assets[2]	$ —	$ 33,176	$ —	$ 33,176

(1) Subsequent to the issuance of the 2010 consolidated financial statements, Idaho Power determined these investments had previously been incorrectly categorized as Level 1 investments within the fair value hierarchy. As a result, the 2010 amounts have been restated to reflect the investments as Level 2.

(2) 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, 2010	$ 20,202	$ 20,783	$ 40,985
Realized losses	—	(47)	(47)
Unrealized gains	1,284	2,211	3,495
Purchases, issuances, and settlements, net	8,446	(878)	7,568
Ending balance - December 31, 2010	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

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.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2011 and 2010.

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 (the Employee Savings Plan). Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $6 million in 2011 and $5 million in 2010.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement. 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, 2011 and 2010 are $3.8 million and $4.5 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 2011 and 2010 (in thousands of dollars):

	2011		2010	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,832,287	2.22%	$ 1,792,305	2.23%
Transmission	871,784	2.06%	855,202	2.03%
Distribution	1,434,925	3.12%	1,377,239	3.13%
General and Other	327,877	7.32%	307,308	7.41%
Total in service	4,466,873	2.83%	4,332,054	2.84%
Accumulated provision for depreciation	(1,840,782)		(1,771,655)	
In service - net	$ 2,626,091		$ 2,560,399	

In 2010, Idaho Power sold $19 million of transmission-related assets to PacifiCorp at book value.

Idaho Power has interests in three jointly-owned generating facilities included in the table above. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of related fuel expenses as well as direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of Idaho Power's participation, were as follows at December 31, 2011 (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	$539,294	$8,334	$276,375	33	771

Boardman	Boardman, OR	79,714	940	53,843	10	64
Valmy Units 1 and 2	Winnemucca, NV	350,582	7,352	202,811	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 $65 million and $76 million in 2011 and 2010, 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 and $8 million in 2011 and 2010, respectively.

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 Order No. 29414 from the IPUC. The regulatory assets recorded under this order do not earn a return on investment.

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 2011, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $3.9 million in the recorded AROs. The primary cause of the increase in the AROs was the decision to decommission the Boardman generating facility at December 31, 2020. A decommissioning study was performed, and now that a removal date has been determined and the fair value of the associated liabilities can be estimated, ARO amounts related to the Boardman decommissioning are being recognized in the consolidated financial statements.

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 Balance Sheets as of December 31, 2011 and 2010.

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

	2011	2010
Balance at beginning of year	$ 16,952	$ 16,240
Accretion expense	936	819
Revisions in estimated cash flows	3,930	929
Liability settled	(451)	(1,036)
Balance at end of year	$ 21,367	$ 16,952

13. INVESTMENTS IN DEBT AND EQUITY SECURITIES

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

	2011	2010
Idaho Power investments:		
IERCo	$ 78,530	$ 90,045
Available-for-sale equity securities	22,205	24,561
Executive deferred compensation plan	3,439	4,746
Other investments	2	3
Total Idaho Power investments	$ 104,176	$ 119,805

Investments in Debt and Equity Securities

Investments in 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 (in thousands of dollars)

	December 31, 2011			December 31, 2010		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale Securities	$ 4,220	$ 1	$ 22,205	$ 4,876	$ -	$ 24,561

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, 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. At December 31, 2010, no securities were in an unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2011 or 2010.

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, 2011 and 2010 (in thousands of dollars).

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
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
December 31, 2010				
Current:				
Financial swaps	Other current assets	$ 930	Other current assets	$ 356
Financial swaps	Other current liabilities	2,440	Other current liabilities	4,172
Forward contracts			Other current liabilities	508
Long-term:				
Financial swaps	Other liabilities	100	Other liabilities	138
Total		$ 3,470		$ 5,174

The table below presents the gains and losses on derivatives not designated as hedging instruments for the year ended December 31, 2011 and 2010 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	**Gain/(Loss) on Derivatives Recognized in Income(1)**	
		2011	**2010**
Financial swaps	Off-system sales	$ 9,594	$ 4,499
Financial swaps	Purchased power	(7,124)	(12,240)
Financial swaps	Fuel expense	501	(101)
Financial swaps	Other operations and maintenance	425	-

Forward contracts	Fuel Expense	-	(721)

(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, 2011 and 2010 set forth in the table below.

Commodity	Units	December 31, 2011	December 31, 2010
Electricity purchases	MWh	225,600	347,400
Electricity sales	MWh	1,298,420	338,200
Natural gas purchases	MMBtu	7,928,311	647,900
Natural gas sales	MMBtu	352,129	—
Diesel purchases	Gallons	1,273,997	1,061,969

Credit Risk

At December 31, 2011, 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, 2011, was $7.0 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, 2011, Idaho Power would have been required to post $4.4 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 sheet 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, 2011 and 2010 (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.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2011				
Assets:				
Derivatives	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100
Trading securities: Equity securities	3,439	—	—	3,439
Available-for-sale securities: Equity securities	22,205	—	—	22,205
Liabilities:				
Derivatives	$ 405	$ 4,302	$ —	$ 4,707

December 31, 2010				
Assets:				
Derivatives	$ 573	$ —	$ —	$ 573
Money market funds	151,173	—	—	151,173
Trading securities: Equity securities	4,746	—	—	4,746
Available-for-sale securities: Equity securities	24,561	—	—	24,561
Liabilities:				
Derivatives	$ —	$ 508	$ —	$ 508

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, 2011 and 2010, 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 are based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Long-term debt	$ 1,491,727	$ 1,737,912	$ 1,612,790	$ 1,621,425

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 2011and 2010.

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 and $8 million to Ida-West in 2011 and 2010, respectively.

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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	04/13/2012	End of 2011/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,467,327,227	4,467,327,227
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,467,327,227	4,467,327,227
9	Leased to Others		
10	Held for Future Use	6,974,407	6,974,407
11	Construction Work in Progress	591,474,855	591,474,855
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	5,065,322,040	5,065,322,040
14	Accum Prov for Depr, Amort, & Depl	1,840,782,085	1,840,782,085
15	Net Utility Plant (13 less 14)	3,224,539,955	3,224,539,955
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,818,635,521	1,818,635,521
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,587,758	22,587,758
22	Total In Service (18 thru 21)	1,841,223,279	1,841,223,279
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	-441,194	-441,194
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,840,782,085	1,840,782,085

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	23,165,537	5,855
4	(303) Miscellaneous Intangible Plant	32,983,581	6,847,330
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,154,821	6,853,185
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,604,032	111,368
9	(311) Structures and Improvements	139,165,207	5,928,618
10	(312) Boiler Plant Equipment	549,065,614	29,667,912
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	148,799,889	3,873,534
13	(315) Accessory Electric Equipment	59,886,756	613,770
14	(316) Misc. Power Plant Equipment	15,486,549	151,084
15	(317) Asset Retirement Costs for Steam Production	3,515,987	4,489,239
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	917,524,034	44,835,525
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	30,109,969	22,901
28	(331) Structures and Improvements	155,425,385	829,675
29	(332) Reservoirs, Dams, and Waterways	250,750,878	2,241,359
30	(333) Water Wheels, Turbines, and Generators	194,277,265	3,939,061
31	(334) Accessory Electric Equipment	43,762,085	2,219,556
32	(335) Misc. Power PLant Equipment	18,088,684	1,048,665
33	(336) Roads, Railroads, and Bridges	7,521,793	590,698
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	699,936,059	10,891,915
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,599,695	90,311
38	(341) Structures and Improvements	7,169,595	
39	(342) Fuel Holders, Products, and Accessories	4,445,866	
40	(343) Prime Movers	100,801,636	773,156
41	(344) Generators	31,681,900	
42	(345) Accessory Electric Equipment	25,027,598	49,984
43	(346) Misc. Power Plant Equipment	3,118,644	19,793
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	174,844,934	933,244
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,792,305,027	56,660,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
			23,171,392		3
5,513,809			34,317,102		4
5,513,809			57,494,197		5
					6
					7
8,291			1,707,109		8
1,335,178			143,758,647		9
9,249,301			569,484,225		10
					11
2,022,617			150,650,806		12
374,396			60,126,130		13
457,158			15,180,475		14
			8,005,226		15
13,446,941			948,912,618		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			30,132,870		27
28,047			156,227,013		28
102,137			252,890,100		29
295,465			197,920,861		30
127,274			45,854,367		31
55,915			19,081,434		32
			8,112,491		33
					34
608,838			710,219,136		35
					36
			2,690,006		37
			7,169,595		38
			4,445,866		39
2,623,096			98,951,696		40
			31,681,900		41
			25,077,582		42
			3,138,437		43
					44
2,623,096			173,155,082		45
16,678,875			1,832,286,836		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	04/13/2012	End of 2011/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	34,253,938	877,421
49	(352) Structures and Improvements	55,667,437	2,493,112
50	(353) Station Equipment	349,451,391	8,846,585
51	(354) Towers and Fixtures	144,723,540	2,767,876
52	(355) Poles and Fixtures	101,621,493	7,282,014
53	(356) Overhead Conductors and Devices	169,165,595	4,102,430
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	318,351	94,995
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	855,201,745	26,464,433
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,745,189	683,210
61	(361) Structures and Improvements	29,485,862	2,881,866
62	(362) Station Equipment	182,593,962	12,192,049
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	225,059,905	5,449,895
65	(365) Overhead Conductors and Devices	120,135,601	3,972,582
66	(366) Underground Conduit	48,215,714	-143,831
67	(367) Underground Conductors and Devices	191,494,213	6,029,113
68	(368) Line Transformers	414,782,133	19,583,109
69	(369) Services	57,319,909	149,486
70	(370) Meters	95,697,525	17,507,437
71	(371) Installations on Customer Premises	2,750,899	84,107
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,370,514	58,890
74	(374) Asset Retirement Costs for Distribution Plant	587,980	55,659
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,377,239,406	68,503,572
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	11,123,762	5,004,896
87	(390) Structures and Improvements	77,278,614	7,882,958
88	(391) Office Furniture and Equipment	39,375,541	5,791,888
89	(392) Transportation Equipment	60,957,305	1,751,643
90	(393) Stores Equipment	1,459,340	205,305
91	(394) Tools, Shop and Garage Equipment	5,567,522	682,923
92	(395) Laboratory Equipment	11,946,695	669,571
93	(396) Power Operated Equipment	9,922,182	904,660
94	(397) Communication Equipment	29,214,145	3,918,370
95	(398) Miscellaneous Equipment	4,762,597	759,121
96	SUBTOTAL (Enter Total of lines 86 thru 95)	251,607,703	27,571,335
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)	251,607,703	27,571,335
100	TOTAL (Accounts 101 and 106)	4,332,508,702	186,053,209
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)	4,332,508,702	186,053,209

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
754			35,130,605		48
165,752			57,994,797		49
6,373,227			351,924,749		50
			147,491,416		51
1,876,594			107,026,913		52
1,466,062			171,801,963		53
					54
					55
			413,346		56
					57
9,882,389			871,783,789		58
					59
4,928			5,423,471		60
31,545			32,336,183		61
595,771			194,190,240		62
					63
1,629,356			228,880,444		64
1,571,292			122,536,891		65
82,538			47,989,345		66
822,355			196,700,971		67
4,945,686			429,419,556		68
244,186			57,225,209		69
775,113			112,429,849		70
80,386			2,754,620		71
					72
34,549			4,394,855		73
			643,639		74
10,817,705			1,434,925,273		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			16,128,658		86
176,785			84,984,787		87
4,609,073			40,558,356		88
1,730,819			60,978,129		89
64,609			1,600,036		90
195,449			6,054,996		91
749,944			11,866,322		92
130,356			10,696,486		93
418,171			32,714,344		94
266,700			5,255,018		95
8,341,906			270,837,132		96
					97
					98
8,341,906			270,837,132		99
51,234,684			4,467,327,227		100
					101
					102
					103
51,234,684			4,467,327,227		104

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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			112,704
4	Transmission Stations			429,822
5	Transmission Lines			68,619
6	Distribution Stations			1,078,590
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				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			6,974,407

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	LANGLEY GULCH POWER PLANT CONS	323,852,696
2	ROLLUP RELIC COST BROWNLEE	53,428,991
3	ROLLUP RELIC COST HELLS CANYON	36,542,791
4	BOARDMAN - HEMINGWAY 500 KV LI	26,168,054
5	GATEWAY WEST 500KV LINE	17,858,788
6	ROLLUP RELIC COST OXBOW	16,825,380
7	HELLS CANYON RELICENSING OUTSI	13,681,208
8	CIAC LIABILITY RECLASS	6,478,737
9	LANGLEY GULCH 138/230 KV LINE	6,447,317
10	WQ - ONGOING HELLS CANYON RELI	6,289,342
11	LANGLEY GULCH SWITCHYARD	6,060,641
12	BRIDGER 2008C123LP U1 TURBINE	4,670,643
13	RIVER ENG.-HELLS CANYON CONTIN	4,342,017
14	LANGLEY GULCH PP CONST: WATER	4,129,634
15	LANGLEY GULCH PP CONST: GAS PI	3,368,213
16	CHQ MASTER PLAN - NEW PRIMARY	2,861,799
17	LANGLEY GULCH 230 KV DOUBLE CI	2,807,084
18	MPSN0802 INCREASE CAPACITY OF	2,557,141
19	FISHERIES-HCC RELICENSING REDB	2,536,812
20	ROLLUP RELIC COST SWAN FALLS	2,527,557
21	HCC RELICENSING, FISH2004 INST	2,390,747
22	FISHERIES-HCC RELICENSING ANAD	2,118,048
23	VALMY 98278700 V1BOTTOM ASH PU	1,957,851
24	BOBN REPLACE C233 AND C234 SER	1,803,202
25	B2H TLINE CONSTRUCTION COSTS	1,780,523
26	AERATION FOR UNIT #5 TO IMPROV	1,754,771
27	LEGAL DEPT. LABOR FOR RELICENS	1,527,841
28	BRIDGER UNDISTRIBUTED WORK ORD	1,515,520
29	REL-HCC OREGON REAUTHORIZATION	1,480,417
30	VALMY UNDISTRIBUTED WORK ORDER	1,399,168
31	SWAN FALLS RELICENSING	1,339,913
32	HC LOCAL SERVICE UPGRADE	1,201,965
33	342 COST CENTER DELIVERY CAPIT	1,143,001
34	314 DESIGN TEAMS - CAPITAL - C	1,120,680
35	PAYROLL & IBNR ACCRUAL	1,089,301
36	OTHER MINOR PROJECTS UNDER $1,000,000	24,417,062
37		
38		
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42		
43	TOTAL	591,474,855

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,750,735,947	1,750,735,947		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	113,001,742	113,001,742		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,954,462	2,954,462		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,272	108,272		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	116,064,476	116,064,476		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	45,706,900	45,706,900		
13	Cost of Removal	6,387,717	6,387,717		
14	Salvage (Credit)	2,607,254	2,607,254		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	49,487,363	49,487,363		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,322,461	1,322,461		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,818,635,521	1,818,635,521		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	527,906,217	527,906,217		
21	Nuclear Production				
22	Hydraulic Production-Conventional	352,777,683	352,777,683		
23	Hydraulic Production-Pumped Storage				
24	Other Production	30,461,718	30,461,718		
25	Transmission	270,518,301	270,518,301		
26	Distribution	528,960,145	528,960,145		
27	Regional Transmission and Market Operation				
28	General	108,011,457	108,011,457		
29	TOTAL (Enter Total of lines 20 thru 28)	1,818,635,521	1,818,635,521		

Schedule Page: 219 Line No.: 14 Column: b

Relocation reimbursements, Up and down costs and damage and insurance claims	$	(952,342)

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	$	(370,120)

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	04/13/2012	End of 2011/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			70,098,680
5				
6	Subtotal Idaho Energy Resources Company			72,561,774
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	72,561,774

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
5,967,745		76,066,425		4
				5
5,967,745		78,529,519		6
				7
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5,967,745		78,529,519		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	04/13/2012	End of 2011/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)	27,546,983	47,865,097	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)	14,416,312	14,808,824	
8	Transmission Plant (Estimated)	13,365,654	12,917,846	
9	Distribution Plant (Estimated)	13,541,576	13,087,873	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	897,634	1,201,188	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	42,221,176	42,015,731	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,379,745	4,474,719	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	73,147,904	94,355,547	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	RLE TRANS SIS 74668832	1,480	186623	17,936	186623
3	IPCM TRANS SIS 74705988,74705990,				
4	74705993, 74705995, 74706017	2,669	186623	(1,913)	186623
5	IPCM TRANS SIS 74785240	7,635	186623	2,365	186623
6	IPCM TRANS SIS 74822581-74822582	3,801	186623	5,233	186623
7	IPCM TRANS SIS74875628-74875626	2,631	186623	7,369	186623
8	IPCM TRANS SIS 74875653-74875654-				
9	74875656		186623	10,000	186623
10	IPCM TRANS SIS74905894-74905896		186623	10,000	186623
11	IPCM TRANS SIS 74993330	1,859	186623	(1,859)	186623
12	IPCM TRANS SIS 74978926-74978929	13,558	186623	(13,558)	186623
13					
14					
15					
16					
17					
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19					
20					
21	**Generation Studies**				
22	LAVA BEDS WIND PARK	4,452	186623		186623
23	GENERATOR CLUSTER GROUP 1	4,373	186623	95,890	186623
24	HIDDEN HOLLOW EXPANSION GI#291	2,477	186623		186623
25	LITTLE WOOD RIVER GI#292		186623	(1,620)	186623
26	ROCKLAND WIND FARM PROJECT 293	12,491	186623	(9,389)	186623
27	WHEATGRASS RIDGE WIND PROJECT 294	30,811	186623	(93,587)	186623
28	COTTEREL MTN WIND PROJECT 302	14,005	186623		186623
29	ADAMS COUNTY BIOMASS GI#304	65	186623		186623
30	ANTELOPE RIDGE WIND PROJECT 306	1,237	186623	86,209	186623
31	SWAGER FARMS GI#307	2,927	186623	(19,526)	186623
32	DOUBLE B DAIRY GI#308	1,863	186623	(650)	186623
33	ROCK CREEK DAIRY GI#309	1,769	186623	(2,166)	186623
34	GRAND VIEW SOLAR GI#312	1,081	186623		186623
35	YELLOWSTONE PWR GI#315	1,450	186623		186623
36	STANFORD RANCH GI#318	4,661	186623	23,208	186623
37	ROGERSON FLATS GI 322	4,610	186623	(786)	186623
38	JACK RANCH WIND GI 323		186623	5,000	186623
39	JACK RANCH WIND GI 324		186623	10,000	186623
40	SALMON CREEK GI 325	16,644	186623	(30,000)	186623

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	JACK RANCH WIND GI 327	15,832	186623	(20,584)	186623
23	TUMBLE WEED 34.5 GI 332	17,256	186623		186623
24	BENNETT CREEK SOLAR GI 333		186623	231	186623
25	HIGH MESA WIND GI 334	23,839	186623	(68,201)	186623
26	SLATERS FLAT GI 335		186623	530	186623
27	TWO PONDS GI 336	6,621	186623	82,373	186623
28	RYEGRASS WINDFARM GI 337		186623	(1,077)	186623
29	MAINLINE WINDFARM GI 338		186623	(1,078)	186623
30	HAMMETT HILL WINDFARM GI 339		186623	(1,078)	186623
31	DESERT MEADOW WINDFARM GI 340		186623	(1,078)	186623
32	COLD SPRINGS WINDFARM GI 341		186623	(1,078)	186623
33	BEAR CREEK WIND GI 343	2,763	186623	2,496	186623
34	DYNAMIS LANDFILL GI 344	13,346	186623	(21,667)	186623
35	MURPHY FLATS GI 345	7,182	186623	16,310	186623
36	MURPHY FLAT WIND GI 346	9,714	186623	(99,714)	186623
37	AG POWER GI 348	5,533	186623	10,023	186623
38	NOTCH BUTTE GI 349	22,237	186623		186623
39	DEEP CREEK GI 350		186623	663	186623
40	RAINBOW WEST GI 352	28,929	186623	(59,212)	186623

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	RAINBOW RANCH GI 353		186623	573	186623
23	MALAD STATION GI 354	9,716	186623	(9,930)	186623
24	TRADE DOLLAR MINE GI 355		186623	80	186623
25	SALMON FALLS WIND GI 357	2,303	186623	(101,177)	186623
26	MURPHY FLATS GI 358	1,656	186623	(6,457)	186623
27	NOTCHBUTTE GI 359	14,342	186623	(31,000)	186623
28	FARGO DROP GI 360		186623	(88)	186623
29	AG ENERGY GI 361	553	186623	(553)	186623
30	COLEMAN HYDRO GI 362	5,048	186623	(18,975)	186623
31	EIGHTMILE HYDRO GI 366	352	186623	(352)	186623
32	CLARK CANYON HYDRO GI 367	7,151	186623	(7,151)	186623
33	U3 HYDRO GI 368	2,661	186623	(2,661)	186623
34	GRAND VIEW SOLAR TWO GI 369	2,228	186623	(32,147)	186623
35	MEADOW CREEK WIND GI 370	14,350	186623	(153,446)	186623
36	WONDEROUS WIND GI 371	6,565	186623	(6,565)	186623
37	WEST BOISE WASTE WATER GI 372	214	186623	(214)	186623
38	MTNAIR EXPANSION GI 373-378	21,101	186623	(50,000)	186623
39	BANNOCK COUNTY LANDFILL GI 380	2,078	186623	(10,849)	186623
40	DOUBLE EAGLE DAIRY GI 381	939	186623	(939)	186623

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	FARGO DROP GI 382	9,575	186623	(12,250)	186623
23	BETASEED BIOGAS GI 383	2,913	186623	(1,000)	186623
24	JETTCREEK WINDFARM GI 384		186623	(1,000)	186623
25	PROSPECTOR WINDFARM GI 385		186623	(1,000)	186623
26	BENSON CREEK WINDFARM GI 386		186623	(1,000)	186623
27	DURBIN CREEK WINDFARM GI 387		186623	(1,000)	186623
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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	04/13/2012	End of 2011/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)	15,371,785	1,022,534	107/230	836,897	15,557,422
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	SFAS 133 Mark to Market - ST (182330)	2,239,694	16,405,599	244	14,046,194	4,599,099
5						
6	FAS 133 Mark to Market - LT (182333)	38,140	644,551	244	574,928	107,763
7						
8	FAS 109 Unfunded - Noncurrent (182322)	588,594,650	33,728,127	Various	18,550,599	603,772,178
9						
10	PCA Deferral Idaho - IPUC Order #27660	30,281,079	48,612,766	Various	78,893,845	
11	(Amort period 06/12 thru 05/13) (182323)					
12						
13	PCA Prior Year Deferral Idaho - IPUC Order #27660	(12,721,876)	56,792,870	Various	44,070,994	
14	(Amort period 06/11 thru 05/12) (182324)					
15						
16	Fixed Cost Adjusment Current Year Order #30267	9,474,129	22,833,343	1823	22,034,176	10,273,296
17	(Amort period 06/12 thru 05/13) (182302)					
18						
19	Prior Year FCA IPUC Order #30267 (182309)	2,866,515	61,891,323	1823/400	60,574,666	4,183,172
20						
21	IPUC Grid West loans - IPUC Order #30157	186,434		401	186,434	
22	(Amort period 01/07 - 12/11) (182303)					
23						
24	FERC Grid West Expense - ER08-629-000	195,525		401	83,797	111,728
25	(Amort period 05/08 thru 04/13) (182304)					
26						
27	SFAS 106/158 Post Retirement Benefits	19,031,743	55,020	2283	3,550,586	15,536,177
28	IPUC Order #30256 (182306)					
29						
30	FIN 48 Adjustment Interest Payable	(159,138,028)	160,341,593	282	1,203,565	
31	IPUC Order #30256 (182310)					
32						
33	Pension Deferred FERC Portion (182338)	150,391	1,391,646	1823	1,542,037	
34						
35	Pension Deferred Oregon Order UE-213 (182339)	939,890	439,115	4073	33,518	1,345,487
36						
37	FAS 87 Deferred Pension-IPUC Order #30333 (182321)	8,549,588	27,159,214	Various	18,568,480	17,140,322
38						
39	Unfunded Pension Liability	163,710,092	92,449,107	2283	9,192,434	246,966,765
40	IPUC Order #30256 (182320)					
41						
42	ID DSM Rider Reclass- IPUC Order #29026 (182301)	17,592,938	28,399,653	254	40,670,594	5,321,997
43	PCAM Oregon 2008 OPUC Order #08-238 (182346)	5,956,673	498,312			6,454,985
44	TOTAL	761,425,884	620,622,892		392,854,761	989,194,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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						
2	PCAM Interest Res 2008 OPUC Order #08-238 (182329)	(278,674)	135,798	1823/4210	286,186	-429,062
3						
4	Excess Power Cost Deferral 2007	6,964,691	14,852,011	1823/401	17,054,386	4,762,316
5	IPUC Order #09-189 (182358)					
6						
7	2007 EPC Interest Res IPUC Order #09-189 (182351)	(452,759)	144,480	182/4210	590	-308,869
8						
9	Oregon DSM Rider Reclass-	1,873,675	13,340,738	254	11,676,971	3,537,442
10	OPUC Advice #05-03 (182359)					
11						
12	2009 Reorg IPUC Order #30914	922,622		401	230,655	691,967
13	(Amort period 01/10 thru 12/14) (182318)					
14						
15	OATT Revenue Deferred Reserve IPUC Order #30940	4,675,182	57,346	186	2,668,059	2,064,469
16	(Amort period 01/11 thru 12/13) (182336)					
17						
18	Idaho Pension Cash (182327)	53,169,373	18,681,291	1823/401	32,874,180	38,976,484
19	IPUC Order #31091 Amort Period (06/10 thru 05/11)					
20	IPUC Order #32248 Amort Period (06/11 thru 05/14)					
21						
22	FERC Pension Cash (182328)	1,024,067	981,527	1823/401	1,423,438	582,156
23	IPUC Order #31091 Amort Period (06/10 thru 05/11)					
24	IPUC Order #32248 Amort Period (06/11 thru 05/14)					
25						
26	Excess Power Cost Unbilled Amort (186356)		1,153,467	401	1,296,113	-142,646
27						
28	Cus Efficiency Incentive IPUC Order #32245 (182317)		8,309,903	1823	1,079,179	7,230,724
29						
30	Cus Efficiency Incen Res IPUC Order #32245 (182314)			4210	134,282	-134,282
31						
32	Lidar Surveys IPUC Order #32426		436,047			436,047
33	(Amort period 01/12 thru 12/21) (182361)					
34						
35	Bennett Mtn Maintenance IPUC Order #32426		299,546			299,546
36	(Amort period 01/12 thru 12/15) (182379)					
37						
38	Minor items (18)	208,345	9,565,965	Various	9,516,978	257,332
39						
40						
41						
42						
43						
44	TOTAL	761,425,884	620,622,892		392,854,761	989,194,015

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Schedule Page: 232.1 Line No.: 38 Column: a

Accounts included in minor items:
182305
182316
182331
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182376

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Rents - Rights of way (186160)	773,585	29,483	Various	87,111	715,957
2						
3	Advance Prepaid (186709)	1,433,219		143	65,958	1,367,261
4	Coal Royalties					
5						
6	Security plan (186720)	21,047,429	1,435,137	143/165	3,480,834	19,001,732
7						
8	American Falls Bond Ref(186722)	206,157		401	14,553	191,604
9	(Amort 04/00 - 7/26)					
10						
11	Prepaid Credit Facility(186025)	60,300	1,981,233	165/431	1,048,863	992,670
12	(Amort 10/11 - 10/15)					
13						
14	Company Owned (186726)	5,624,403	2,196,361	Various	2,762,408	5,058,356
15	Life Insurance					
16						
17	American Falls Water Rights	14,674,956		401	1,042,008	13,632,948
18	(Amort 01/06-12/25) (186727)					
19						
20	Milner Bond Guarantee (186734)	7,445,455		253	1,063,637	6,381,818
21	(Amort 02/07 - 2/17)					
22						
23	American Falls - Bond refinance	679,988		401	47,999	631,989
24	(35 year amortization) (186770)					
25						
26	Shelf Registration-2010(186731)	2,383,894	109,135	181/232	2,460,532	32,497
27						
28	Transmission Deposit	687,741	22,837			710,578
29	PacifiCorp (186784)					
30						
31	Prepaid (186052)	308,302	845,063	Various	502,893	650,472
32	Peoplesoft/Passport					
33	(Various Amortization Periods)					
34						
35	Long Term (186121)	1,306,903		228/401	38,447	1,268,456
36	Workers Compensation					
37						
38	OATT Revenue Deferred Reserve	-2,610,713	2,610,713			
39	Order #30940 (186300)					
40	(amort period 3 years start					
41	date not yet determined)					
42						
43	Long-Term Firm (186624)	919,063	30,299	Various	949,362	
44	Trans Deposits					
45						
46	Power Plant- Valmy J (186793)	98,366	72,991	107/401	34,951	136,406
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	55,131,472				50,880,202

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2						
3	Power Plant- Boardman (186794)	76,451	88,541	107/401	60,179	104,813
4						
5	Minor Items & Job Orders (5)	15,973	8,637,388	Various	8,650,716	2,645
6						
7						
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9						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	55,131,472				50,880,202

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Schedule Page: 233.1 Line No.: 5 Column: a

Accounts included in minor items:
186100
186255
186623
186703
186946

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3	Emission Allowances	-509,154	
4	Advances for Construction	7,061,283	5,117,985
5	Other Electric (See footnote)	6,072,776	46,276,158
6			
7	Other (See footnote)	126,631,210	157,500,863
8	TOTAL Electric (Enter Total of lines 2 thru 7)	139,256,115	208,895,006
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	18,090,657	19,082,040
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	157,346,772	227,977,046

Notes

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

(Note 1):

	Ending Balance	Ending Balance
Revenue Sharing	0.00	10,594,313.78
Post Retiree Benefits-VEBA	5,658,260.39	7,474,519.09
AFUDC Hells Canyon Relicensing	8,292,259.43	12,958,192.16
Rate Case Disallowance	2,765,193.22	2,621,255.57
Stock Based Compensation	2,496,071.09	2,777,080.86
Other Employee's Long Term Deferred Compensation	1,855,361.91	1,344,427.39
Post Retirement Benefits	1,504,637.15	1,172,344.50
Deferred Idaho ITC	4,183,991.50	5,539,826.50
Non-VEBA Pension and Benefits	414,231.42	265,356.10
Oregon-Pension Expense	817,275.90	1,504,842.01
FERC Credit OFA	182,023.59	0.00
IRS Interest Expense	93,084.00	0.00
Pension Expense (Acct 228)	(22,197,833.71)	0.00
Deferred GBC	24,000.00	24,000.00
Bonus Deferral	(514.49)	0.00
Delivery Accruals	(15,265.83)	0.00
Total Other Electric	6,072,775.57	46,276,157.96

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

(Note 2):

	Ending Balance	Ending Balance
Pension	64,358,799.67	96,551,656.75
Regulatory Liability for Income Taxes	46,199,137.04	45,472,547.23
Postretirement Plan	8,025,874.06	6,367,217.42
Minimum Pension Liability	8,047,399.21	9,109,441.86
Total Other	126,631,209.98	157,500,863.26

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

(Note 3):

	Ending Balance	Ending Balance
Senior Management Security Plan	15,067,824.46	16,319,200.67
SMSP-Market Change of Rabbi Investments	1,626,015.01	1,626,015.01
Micron-CIAC	1,288,362.93	1,050,481.59
Meridian Gold Contributions	108,454.56	86,342.35
Total Non Electric	18,090,656.96	19,082,039.62

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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				
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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	04/13/2012	End of 2011/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	04/13/2012	End of 2011/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		
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21		
22	TOTAL	2,096,925

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	1,617,045,000	27,130,028

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	100,000,000	4,750,000	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
				1,491,726,818	79,348,955	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	04/13/2012	End of 2011/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	6.60% Series Due 2011	120,000,000	860,502
20			
21	Subtotal Account 221	1,585,460,000	27,130,028
22			
23	Account 222 - Reaquired Bonds		
24			
25	Account 223: Advances for Associated Companies		
26			
27	Account 224:		
28	Bond Guarantee - American Falls	19,885,000	
29	Note Guarantee - Milner Dam	11,700,000	
30	Subtotal Account 224	31,585,000	
31			
32			
33	TOTAL	1,617,045,000	27,130,028

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	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	6/15/2037	140,000,000	8,820,000	4
						5
						6
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	6,250,000	7
						8
						9
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	50,255	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	7/15/2026	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
3/2/01	3/2/11	3/2/01	3/2/11		1,342,000	19
						20
				1,465,460,000	79,348,955	21
						22
						23
						24
						25
						26
						27
04/26/00	2/1/25			19,885,000		28
02/10/92				6,381,818		29
				26,266,818		30
						31
						32
				1,491,726,818	79,348,955	33

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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	04/13/2012	End of 2011/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)	164,749,627
2		
3		
4	Taxable Income Not Reported on Books	
5		22,801,060
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-22,327,229
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		6,698,653
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		130,977,371
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	27,547,434
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	9,641,602
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Schedule Page: 261 Line No.: 5 Column: b

4003-CONSTRUCTION ADV-252	$	(5,552,281)
4005-AVOIDED COST INT CAP		18,471,438
4006-RETIREMENTS-RECORD TAX GAIN/LOSS		4,000,000
4010-EMISSION ALLOWANCE-254.409-411		1,141,995
4013-CIAC AS TAXABLE INC IN ACCT 107		3,748,724
4018-LINDEN FEEDER DEPOSITS-253.206		0
4021-ENGINEERING FEES-IN ACCT 107-FED ONLY		115,387
4022-FERC CREDIT OFA-254.307		(465,593)
4024-GREEN TAG SALES		2,006,420
4501-ROYALTY INCOME BTL		0
4506-CIAC-MERIDIAN GOLD		(56,560)
4507-CIAC-MICRON-DRAM		(608,470)
Total	**$**	**22,801,060**

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

Total Federal and State taxes deducted on books	$	(44,418,448)
5001-BAD DEBT EXPENSE		(205,868)
5010-SFAS 112-POST-EMPLY BEN 182/253		(849,962)
5014-OVERACCRUED VACATION-ACCT 242		176,500
5017-INJURIES & DAMAGES		42,684
5019-DIRECTORS FEES DEF		26,758
5022-CAPITALIZED OVERHEADS		(17,000,000)
5024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.		600,000
5025-MILNER FALLING WATER - REV ACCRL		(334,136)
5027-AMORTIZATION OF ACCOUNT 114		(22,723)
5028-OREGON OPER PROPERTY TAX ADJ		(5,072)
5023-PENSION EXPENSE-Acct 228		5,487,134
5033-NONVEBA PEN&BEN-Acct 228		(380,803)
5035-PCA EXPENSE DEFERRAL		30,679,760
5043-AMERICAN FALLS - FALLING WATER CONTRACT-FT		219,181
5047-OTHER EMPLOYEE'S LT DEFERRED COMP-228		(1,306,905)
5052-AMORTIZATION OF ACCOUNT 181		313,103
5053-STOCK BASED COMPENSATION		645,487
5054-IPUC GRID WEST LOANS-ACCT 182		186,435
5055-OPUC GRID WEST LOANS-ACCT 182		14,191
5056-FERC GRID WEST EXP-ACCT 182		83,796
5057-INTERVENER FUNDING ORDERS-ACCT 182		(54,903)
5058-FIXED COST ADJUSTMENT (FCA)-ACCT 182		(2,115,823)
5059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF		(36,407)
5060-OREGON-PCAM (POWER COST ADJ MECHANISM)		1,220,784
5061-PENSION EXPENSE-OREGON		1,758,706
5062-LIDAR SURVEYS DEFFERAL-ACCT 182		(436,047)
5063-BENNETT MTN MAINT DEFERRAL		(299,546)
5501-SEC PLAN-NET INS COSTS		(76,501)
5503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST		(430,015)
5504-NONDEDUCTIBLE POLITICAL EXP-426.4		875,858
5505-SEC PLAN-BENEFIT ACCR		3,200,861
5510-FINES & PENALTIES-OPERATING		430,042
5531-RATE CASE DISALLOWANCES-REVERSE AMORT		(296,299)
5532-DELIVERY ACCRUALS-253.550		(19,051)

5537-BRIDGER SIERRA RESERVE-LEGAL FEES-Acct 228.4		0
5540-UNREALIZED LOSS ON INVESTMENTS-Acct 124		0
Total	**$**	**(22,327,229)**

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

7010-AFUDC HC RELICENSING-ACCT 229	$	(11,934,857)
7011-OATT REVENUE DEFICIENCY		0
7012-REVENUE SHARING ACCT 25-CURR		(27,098,897)
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		5,967,745
7502-ALLOWANCE FOR OFUDC		25,484,072
7503-ALLOWANCE FOR BFUDC		13,332,724
7504-RECLASS TAX EXEMPT INTEREST-FED ONLY		1,882
7509-SECURITY PLAN-INSURANCE PROCEEDS		945,984
7514-COLI-INSURANCE PROCEEDS		0
7518-IRS INTEREST INCOME		0
Total	**$**	**6,698,653**

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

8001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$	(4,875,119)
8009-DEPR FOR TAX GT OR LT BOOK		82,278,759
8016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D		803,950
8020-CONSERVATION PROGRAMS		(10,607,175)
8025-MANUFACTURING DEDUCTION		2,698,170
8027-NEVADA OPERATING PROPERTY TAX ADJ		(59,445)
8034-REMOVAL COSTS		6,412,380
8038-OREGON EXCESS PWR SUPPLY COSTS		(2,229,258)
8039-ST TAX-NOT DEDUCTED ON PRIOR RETURN		28,337
8041-AM FALLS - UNAMORTIZED DEBT EXP		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT-FT		(911,000)
8057-REORGANIZATION COSTS		(230,656)
8059-SFTWR COSTS-MISC-107-FED ONLY		0
8072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY		1,369,000
8073-REPAIRS DEDUCTION		40,000,000
8077-PP INS & OTR EXP (1 YR OR LESS)-165		1,659,465
8079-CUSTOM EFFICIENCY INCENTIVE PAY		7,096,442
8501-COLI-TAX ADJ FROM BOOKS		158,095
8504-OREGON NONOP PROPERTY TAX ADJUST		(6)
8703-IPCO - 162 (M) $1m THRESHOLD		0
IRS INTEREST EXPENSE		238,097
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		7,195,334
Total	**$**	**130,977,371**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	-21,084,488		7,113,757	-9,913,638	
3	Social Security - (FOAB)	927		12,928,542	12,928,282	
4	Unemployment			120,729	120,729	
5	Subtotal Federal	-21,083,561		20,163,028	3,135,373	
6						
7	State of Idaho:					
8	Property	6,798,477		18,797,490	17,179,867	
9	Non-Operating	11,656		21,567	22,309	
10	Income	1,057,025		7,045,405	8,766,534	
11	KWH	97,149		2,756,722	2,673,193	
12	Unemployment	-1		656,570	656,568	
13	Regulatory Commission			2,089,245	2,089,245	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	7,964,306		31,367,149	31,387,866	
16						
17	State of Oregon					
18	Property		1,177,346	2,361,153	2,366,225	
19	Non-Operating Property		838	1,672	1,667	
20	Income	-52,574		55,453	113,672	
21	Regulatory Commission			148,358	148,358	
22	Unemployment			44,926	44,926	
23	Franchise	178,317		703,382	713,729	
24	Subtotal Oregon	125,743	1,178,184	3,314,944	3,388,577	
25						
26	State of Montana:					
27	Property	105,137		271,151	240,805	
28	Subtotal Montana	105,137		271,151	240,805	
29						
30	State of Nevada:					
31	Property		568,203	1,088,598	1,029,152	
32	Subtotal Nevada		568,203	1,088,598	1,029,152	
33						
34	State of Wyoming					
35	Corporate License			4,513	4,513	
36	Property	635,567		1,527,445	1,399,289	
37	Subtotal Wyoming	635,567		1,531,958	1,403,802	
38	Other States Income	9,936		41,969	247	
39	Payroll Adjustment			-13,750,768		
40						
41	TOTAL	-12,242,872	1,746,387	44,028,029	40,585,822	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
-4,057,093		8,470,295			-1,356,538	2
1,188		12,928,542				3
		120,729				4
-4,055,905		21,519,566			-1,356,538	5
						6
						7
8,416,100		18,017,423			780,067	8
10,914					21,567	9
-664,104		7,293,032			-247,627	10
180,678		2,756,722				11
1		656,570				12
		2,089,245				13
		150				14
7,943,589		30,813,142			554,007	15
						16
						17
	1,182,418	2,287,728			78,425	18
	834				1,672	19
-110,793		68,371			-12,918	20
		148,358				21
		44,926				22
167,970		703,382				23
57,177	1,183,252	3,252,765			62,179	24
						25
						26
135,483		271,151				27
135,483		271,151				28
						29
						30
	508,757	1,088,598				31
	508,757	1,088,598				32
						33
						34
		4,513				35
763,723		1,527,445				36
763,723		1,531,958				37
51,658		46,837			-4,868	38
		-13,750,768				39
						40
4,895,725	1,692,009	44,773,249			-745,220	41

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Schedule Page: 262 Line No.: 1 Column: i

This footnote is for the total of Column I on Page 263. The total of column I and the amounts associated with accounts 408.1 & 409.1 in column I should total back to the sum of lines 14, 15 & 16 on Page 114. For the year 2011 this cross-check will not work as the total of lines 14-16 on Page 114 is $ 74,436,114 additional expense than line 41 on page 263. This difference represents an amount booked for the accounting of FIN 48. When FIN 48 was booked it does use account 409.1, however the other side of the entry is not asociated with FERC account 236 or 165. Therefore FIN 48 will show up in the amount on Page 114 but will not show up on Pages 262 & 263.

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

Account 409.2	$ (638,707)
234.2	(717,831)
Total	$ (1,356,538)

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

Account 107 $ 780,067

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

Account 409.2 $ 21,567

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

Account 409.2	$ (104,386)
234	(143,241)
Total	$ (247,627)

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

Account 107 $ 73,425

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

Account 409.2 $ 1,672

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

Account 409.2	$ (5,634)
234	(7,284)
Total	$ (12,918)

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

Account 409.2	$ (2,440)
234	(2,428)
Total	$ (4,868)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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%	736,844				71,532	
4	7%						
5	10%	25,512,684				1,557,544	
6		1,266,978				26,723	
7	Other - State	44,455,829	411.4	2,222,830	411.4	1,698,965	
8	TOTAL	71,972,335		2,222,830		3,354,764	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	44,455,830	411.4	2,222,830	411.4	1,698,965	
13							
14							
15							
16							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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
665,312	10.30		3
			4
23,955,140	16.38		5
1,240,255	47.41		6
44,979,694	26.17		7
70,840,401			8
			9
			10
			11
44,979,695			12
			13
			14
			15
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	10,038,255	107/401	170,178,139	172,904,103	12,764,219
2						
3	Point to Point Trans Study(253201)	793,286	232	185,996	268,863	876,153
4						
5	FTV (253202)	4,466,666	400	400,000		4,066,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Sho Ban Trans ROW (253480)	262,500	242	15,000		247,500
9	(Amort Period Jan 2005-Dec 2027)					
10						
11	Milner Falling Water (253953)	1,432,559	186/401	1,063,636	729,498	1,098,421
12	Amort Period (Feb 1992 - Feb 2017)					
13						
14	Postretirement Benefits (253960)	3,848,669	401	849,962		2,998,707
15						
16	Directors Deferred Compensation	4,611,550	131	571,167	597,925	4,638,308
17	(253980-253999)					
18						
19	IBM Mainframe Software Licenses	1,121,312	232	386,459		734,853
20	(Amort period 2010-2015) (253950)					
21						
22	USAF Battery Replacement (253906)	74,384			31,322	105,706
23						
24	Minor Items (2)	19,088	107/401	49,977	30,928	39
25						
26						
27						
28						
29						
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34						
35						
36						
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38						
39						
40						
41						
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44						
45						
46						
47	TOTAL	26,668,269		173,700,336	174,562,639	27,530,572

Schedule Page: 269 Line No.: 24 Column: a

Accounts included in minor items:
253042
253550

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	284,793,872	50,711,765	2,171,003
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	284,793,872	50,711,765	2,171,003
6	Non-Operating Property			
7	Other - Regulatory Asset for I	422,215,476		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	707,009,348	50,711,765	2,171,003
10	Classification of TOTAL			
11	Federal Income Tax	601,940,143	50,211,165	2,171,003
12	State Income Tax	105,069,205	500,601	
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) 04/13/2012	Year/Period of Report End of 2011/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
						333,334,634	2
							3
							4
						333,334,634	5
							6
		182	-159,138,028	182	18,638,086	599,991,590	7
							8
			-159,138,028		18,638,086	933,326,224	9
							10
			-133,493,583		12,489,768	795,963,656	11
			-25,644,445		6,148,319	137,362,570	12
							13

NOTES (Continued)

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Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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

	2011	Changes during Year				Adj Dr		Adj Credits		2011
	Beginning	DR to	CR to	DR	CR	Acct		Acct		Ending
Account (a)	Balance b	410.1 c	411.1 d	410.2 e	411.2 f	cr g	Amt h	dr i	Amt j	Balance k
Accelerated Depreciation	271,486,739.45	49,981,168.35	0.00							321,467,907.80
Intangible Asset-Labor Deduction	13,260,622.55	556,722.60								13,817,345.15
Valmy Capitalized Items	427,766.00		76,500.00							351,266.00
Engineering Fees in Acct 107	(141,663.20)	8,552.25	40,385.45							(173,496.40)
Misc Software Develop Costs	83,927.20	(66,271.80)								17,655.40
Taxable CIAC in CWIP Bal.	(323,520.40)	231,593.95	2,054,117.45							(2,146,043.90)
TOTAL	284,793,871.60	50,711,765.35	2,171,002.90	0	0		0		0	333,334,634.05

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	25,656,008	53,826,297	46,760,251
4				
5				
6				
7				
8	Other -- See Note	73,705,667		
9	TOTAL Electric (Total of lines 3 thru 8)	99,361,675	53,826,297	46,760,251
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	265,485		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	99,627,160	53,826,297	46,760,251
20	Classification of TOTAL			
21	Federal Income Tax	83,572,690	45,152,408	39,225,027
22	State Income Tax	16,054,470	8,673,888	7,535,224
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						32,722,054	3
							4
							5
							6
							7
					30,569,445	104,275,112	8
					30,569,445	136,997,166	9
							10
							11
							12
							13
							14
							15
							16
							17
212,793	36,749					441,529	18
212,793	36,749				30,569,445	137,438,695	19
							20
178,503	30,827				25,643,297	115,291,044	21
34,291	5,922				4,926,147	22,147,650	22
							23

NOTES (Continued)

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Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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

	2011	Changes during Year				Adj Debits		Adj Credits		2011
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
PCA Expense Deferral	7,056,724.48	5,694,011.99	17,880,218.67							(5,129,482.20)
Conservation Programs	7,610,472.36	5,178,152.68	6,550,673.77							6,237,951.27
Oregon Excess Power Costs	2,556,836.05	828,970.77	1,700,499.18							1,685,307.64
Oregon PCAM	2,219,813.71	123,399.85	600,664.96							1,742,548.60
IPUC Grid West Loans	72,887.11		72,887.11							(0.00)
OATT Revenue Deficiency	807,104.17	0.00	0.00							807,104.17
Reorganization Costs	360,699.07		90,174.97							270,524.10
FERC Grid West Expense	76,440.49		32,760.44							43,680.05
OPUC Grid West Loans	23,116.10	0.00	5,547.97							17,568.13
Intervenor Funding Orders	47,339.76	21,464.33	0.79							68,803.30
Fixed Cost Adjustment	4,824,574.81	4,456,672.84	3,629,491.45							5,651,756.20
PS & I Costs-Coal & CHP Plants-Write Off	(0.02)	14,233.35	0.01							14,233.32
Delivery accruals	0.00	33,341.78	39,163.41							(5,821.63)
Emission Allowance	0.00	142,974.34	47,832.35							95,141.99
Green Tag Sales	0.00	1,644,051.09	784,409.90							859,641.19
LIDAR Surveys Deferral	0.00	170,472.57								170,472.57
Bennett Mtn Maintenance Deferral	0.00	117,107.51								117,107.51
Bonus Deferral	0.00	514.49	12,167.15							(11,652.66)
Pension	0.00	35,400,929.09	15,313,758.58							20,087,170.51
TOTAL	25,656,008.09	53,826,296.68	46,760,250.71	0	0		0		0	32,722,054.06

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

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	64,358,799.67							190	32,192,857.08	96,551,656.75
Postretirement Plan	7,440,460.06							190	(1,366,591.53)	6,073,868.53
Unrealized gains on Mkt Securities	1,906,407.25							219	(256,821.00)	1,649,586.25
TOTAL	73,705,666.98	0	0	0	0		0		30,569,444.55	104,275,111.53

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

	2011	Changes during Year				Adj Debits		Adj Credits		2011
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
Advance Coal Royalties	293,553.80			7,931.99	0.00					301,485.79
Oregon Non-Op Prop Tax Adj	327.64			327.61	329.59					325.66
Unrealized Gain/Loss From Rabbit Trust	(28,396.63)			204,533.72	36,419.34					139,717.75
TOTAL	265,484.81	0	0	212,793.32	36,748.93		0		0	441,529.20

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - (254001)	573,226	175	5,235,834	8,057,573	3,394,965
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)		175	1,028,788	1,388,206	359,418
5	IPUC Order # 28661					
6						
7	Emission Sales (254412)	371,211	Various	375,357	9,894	5,748
8	IEEP- Order #30529					
9						
10	Unfunded Accum Def Income Tax (254966)	46,199,138	Various	4,890,414	4,163,823	45,472,547
11						
12	FERC Credit for OFA - IPUC Order #30754	465,593	401	465,593		
13	(Amort period 09/06 - 09/11) (254307)					
14						
15	Oregon Solar Pilot - (254005)	197,625	Various	177,834	746,305	766,096
16	Advice # 10-11					
17						
18	Oregon Reclass (254204)		1823	17,123,830	21,234,150	4,110,320
19	Advice # 05-03					
20						
21	Green Tags Oregon (254415)	195,265	Various	251,458	335,798	279,605
22						
23	Power Cost Adjustment-Current (254423)		1823	36,757,136	47,336,082	10,578,946
24						
25	Regulatory Unfunded Accum Def Income Tax (254419)	7,241,146	1823	8,290,308	4,829,750	3,780,588
26						
27	Revenue Sharing (254101)		Various		27,098,897	27,098,897
28	IPUC Order #30978					
29						
30	BPA Credit Residential Idaho (254401)	13,880	Various	111	397,788	411,557
31	Advice # 11-03					
32						
33	WAQC Carryover (254901)		Various	1,323	160,632	159,309
34	IPUC Order #29505					
35						
36	Minor Items (10)	22,818	Various	118,237,871	118,280,302	65,249
37						
38						
39						
40						
41	TOTAL	55,279,902		192,835,857	234,039,200	96,483,245

Schedule Page: 278 Line No.: 36 Column: a

Accounts included in minor items:
254004
254006
254201
254202
254402
254403
254404
254409
254410
254411
254413
254416

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	405,981,556	400,606,630
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	322,307,065	338,716,361
5	Large (or Ind.) (See Instr. 4)	140,701,371	138,394,166
6	(444) Public Street and Highway Lighting	3,289,385	3,278,628
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	872,279,377	880,995,785
11	(447) Sales for Resale	101,602,140	78,133,502
12	TOTAL Sales of Electricity	973,881,517	959,129,287
13	(Less) (449.1) Provision for Rate Refunds	37,734,709	10,667,522
14	TOTAL Revenues Net of Prov. for Refunds	936,146,808	948,461,765
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,564,200	3,532,831
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	24,256,300	21,141,127
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	38,244,930	44,517,995
22	(456.1) Revenues from Transmission of Electricity of Others	19,372,904	15,398,402
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	85,438,334	84,590,355
27	TOTAL Electric Operating Revenues	1,021,585,142	1,033,052,120

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
5,146,013	4,967,379	409,786	407,551	2
				3
5,458,954	5,439,730	82,045	81,571	4
3,099,743	3,075,379	123	124	5
29,720	30,016	1,578	1,459	6
				7
				8
				9
13,734,430	13,512,504	493,532	490,705	10
3,634,924	1,981,936			11
17,369,354	15,494,440	493,532	490,705	12
				13
17,369,354	15,494,440	493,532	490,705	14

Line 12, column (b) includes $ 640,470 of unbilled revenues.

Line 12, column (d) includes 38,351 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	5,113,748	402,275,493	409,683	12,482	0.0787
3	03 - Residential Master Meter	4,962	371,277	22	225,545	0.0748
4	04 - Residential - EW	528	41,192	31	17,032	0.0780
5	05 - Residential - TOD	912	71,020	50	18,240	0.0779
6	15 - Dusk to dawn lighting	2,859	537,868			0.1881
7	Unbilled Revenues	22,994	827,035			0.0360
8	Other Revenues		1,862,085			
9	Total 440	5,146,003	405,985,970	409,786	12,558	0.0789
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	162,322	16,053,391	30,972	5,241	0.0989
13	09 - General service	431,095	20,549,318	187	2,305,321	0.0477
14	09 - General service	3,156,665	178,829,445	31,007	101,805	0.0567
15	09 - General service	5,506	294,295	3	1,835,333	0.0534
16	15 - Dusk to Dawn Light	4,103	698,315			0.1702
17	19 - Uniform rate contracts	2,103,035	89,329,869	115	18,287,261	0.0425
18	19 - Uniform rate contracts	6,679	315,835	1	6,679,000	0.0473
19	19 - Uniform rate contracts	119,113	5,280,572	4	29,778,250	0.0443
20	24 - Irrigation Pumping	1,673,408	104,613,138	18,702	89,477	0.0625
21	40 - General service	12,997	877,108	1,174	11,071	0.0675
22	Commercial & Industrial & Unbill	883,784	45,989,630	4	220,946,000	0.0520
23	Other Revenues		173,106			
24	Total 442	8,558,707	463,004,022	82,169	104,160	0.0541
25						
26	444 - Public Street Lighting:					
27	40 - General service	2,824	190,905	839	3,366	0.0676
28	41 - Street lighting	23,946	2,962,492	355	67,454	0.1237
29	42 - Traffic control lighting	2,998	141,953	384	7,807	0.0473
30	Other Revenues	-48	-5,965			0.1243
31	Total 444	29,720	3,289,385	1,578	18,834	0.1107
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,696,079	871,638,906	493,533	27,751	0.0636
42	Total Unbilled Rev.(See Instr. 6)	38,351	640,471	0	0	0.0167
43	TOTAL	13,734,430	872,279,377	493,533	27,829	0.0635

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

This amount is different from page 301 column D line 2 in the amount of 10 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 4,414 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.: 24 Column: b

This amount is different from page 301 column D total of lines 4 and 5 in the amount of 10 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.: 24 Column: c

This amount is different from page 301 column B total of lines 4 and 5 in the amount of 4,414 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	04/13/2012	End of 2011/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	RQ	V6-44	8.436	8.436	7.176
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3						
4	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
5	Arizona Public Service Co.	OS	WSPP	n/a	n/a	n/a
6	Avista Corp.	SF	WSPP	n/a	n/a	n/a
7	Avista Corp.	OS	WSPP	n/a	n/a	n/a
8	Barclays Bank PLC	SF	WSPP	n/a	n/a	n/a
9	Barclays Bank PLC	OS	-	n/a	n/a	n/a
10	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
11	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
12	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
13	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
14	BP Energy Company	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
38,222	540,239	1,085,425	4,500	1,630,164	1
			254,060	254,060	2
					3
533,806		13,314,698		13,314,698	4
3,600		93,600		93,600	5
4,050		84,748		84,748	6
290		3,140		3,140	7
30,000		1,502,700		1,502,700	8
		94,553		94,553	9
			2,295	2,295	10
34,301		702,444		702,444	11
44,873		779,325		779,325	12
55,635		1,528,500		1,528,500	13
63,160		717,310		717,310	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
2	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
3	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
4	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
5	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
6	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
7	Citigroup Energy Inc.	OS	WSPP	n/a	n/a	n/a
8	Citigroup Energy Inc.	OS	-	n/a	n/a	n/a
9	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
10	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
11	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
12	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
13	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
14	Exelon Generation Company, LLC	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10		378		378	1
		14,492		14,492	2
			695,944	695,944	3
951		23,623		23,623	4
386,461		11,442,864		11,442,864	5
560,092		13,799,257		13,799,257	6
6,244		167,095		167,095	7
		341,599		341,599	8
16,800		463,000		463,000	9
44,800		1,155,785		1,155,785	10
42,750		1,091,669		1,091,669	11
85,400		2,461,720		2,461,720	12
13,710		248,556		248,556	13
800		26,400		26,400	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Grant CO Public Utility District #2 --	SF	WSPP	n/a	n/a	n/a
2	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
3	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
4	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
5	IBERDROLA RENEWABLES, Inc.	OS	-	n/a	n/a	n/a
6	J.P. Morgan Ventures Energy Corporation	OS	-	n/a	n/a	n/a
7	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
8	Jeffries Bache	OS	-	n/a	n/a	n/a
9	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
10	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
11	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
12	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
13	Morgan Stanley Capital Group Inc.	SF	V6-62	n/a	n/a	n/a
14	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
5,600		151,320		151,320	1
			9,407	9,407	2
127,040		3,325,760		3,325,760	3
341		7,408		7,408	4
		68,748		68,748	5
		765,968		765,968	6
10,422		325,674		325,674	7
		6,807,639		6,807,639	8
		524,508		524,508	9
169,183		5,696,223		5,696,223	10
		138,330		138,330	11
		10,732		10,732	12
225,125		4,786,783		4,786,783	13
			111,981	111,981	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
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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	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
2	PacifiCorp Inc.	S	WSPP	n/a	n/a	n/a
3	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
4	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
5	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
6	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
7	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
8	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
9	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
10	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
11	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
12	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
13	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
14	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,258		27,573		27,573	1
68,075		894,457		894,457	2
			158	158	3
190		4,970		4,970	4
			584	584	5
2,925		34,350		34,350	6
16,671		412,810		412,810	7
			490,861	490,861	8
196,235		2,540,384		2,540,384	9
34,508		856,711		856,711	10
			14,900	14,900	11
335		2,459		2,459	12
56,880		1,609,656		1,609,656	13
57,402		1,451,355		1,451,355	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Puget Sound Energy, Inc.	SF	T-7	n/a	n/a	n/a
2	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
3	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
4	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
5	Royal Bank of Canada	OS	-	n/a	n/a	n/a
6	Seattle City Light	OS	WSPP	n/a	n/a	n/a
7	Seattle City Light	SF	WSPP	n/a	n/a	n/a
8	Sempra Energy Trading LLC	OS	-	n/a	n/a	n/a
9	Sempra Energy Trading LLC	OS	WSPP	n/a	n/a	n/a
10	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
11	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
12	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
13	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
14	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
3		88		88	1
15,915		228,295		228,295	2
			126,369	126,369	3
132,200		3,796,180		3,796,180	4
		142,696		142,696	5
1,100		13,675		13,675	6
4,140		109,050		109,050	7
		672,024		672,024	8
			29	29	9
		37,302		37,302	10
			15,451	15,451	11
3,584		99,168		99,168	12
41,696		864,566		864,566	13
286,405		7,531,637		7,531,637	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

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

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

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

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

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 Energy	SF	T-7	n/a	n/a	n/a
2	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
3	Sierra Pacific Power Co., dba NV Energy	SF	WSPP	n/a	n/a	n/a
4	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
5	Southern California Edison	OS	WSPP	n/a	n/a	n/a
6	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
7	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
8	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
9	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
10	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
11	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
12	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
13	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
14	Turlock Irrigation District	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
69		2,066		2,066	1
			194,888	194,888	2
200		6,000		6,000	3
2		52		52	4
			109	109	5
50		1,100		1,100	6
			2,547	2,547	7
100		2,500		2,500	8
14,393		115,296		115,296	9
250		6,200		6,200	10
			10,764	10,764	11
141,558		2,419,207		2,419,207	12
51,664		1,377,652		1,377,652	13
400		10,028		10,028	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	United Materials of Great Falls	LF	61	n/a	n/a	n/a
2	Wells Fargo Bank, N.A.	OS	-	n/a	n/a	n/a
3	Marcquarie Energy LLC	AD	WSPP	n/a	n/a	n/a
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
		26,446		26,446	1
		77,127		77,127	2
50		2,000		2,000	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/13/2012	2011/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: b
Customer Charge

Schedule Page: 310 Line No.: 2 Column: b
Network Transmission Charges

Schedule Page: 310 Line No.: 5 Column: b
Non-firm Sales

Schedule Page: 310 Line No.: 7 Column: b
Non-firm Sales

Schedule Page: 310 Line No.: 9 Column: b
ISDA Master Agreement with Barclays Bank dated May 2, 2011

Schedule Page: 310 Line No.: 10 Column: b
Financial Transmission Losses

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

Schedule Page: 310.1 Line No.: 2 Column: b
ISDA Master Agreement with Cargil Powr Markets LLC, dated June 13, 2011

Schedule Page: 310.1 Line No.: 3 Column: b
Financial Transmission Losses

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

Schedule Page: 310.1 Line No.: 7 Column: b
Unit Contingent

Schedule Page: 310.1 Line No.: 8 Column: b
ISDA Master Agreement with Citigroup Energy, Inc., dated March 7, 2011

Schedule Page: 310.2 Line No.: 2 Column: b
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 4 Column: b
Non-firm Sales

Schedule Page: 310.2 Line No.: 5 Column: b
ISDA Master Agreement with Iberdrola Renewables, Inc., dated July 19, 2011

Schedule Page: 310.2 Line No.: 6 Column: b
ISDA Master Agreement with JP Morgan Ventures Energy Corporation dated November 4, 2005.

Schedule Page: 310.2 Line No.: 8 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4, 2008.

Schedule Page: 310.2 Line No.: 9 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

Schedule Page: 310.2 Line No.: 11 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000

Schedule Page: 310.2 Line No.: 12 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000

Schedule Page: 310.2 Line No.: 14 Column: b
Financial Transmission Losses

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

Schedule Page: 310.3 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 310.3 Line No.: 5 Column: b
Financial Transmission Losses

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

Schedule Page: 310.3 Line No.: 8 Column: b

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Financial Transmission Losses

Schedule Page: 310.3 Line No.: 9 Column: b

Non-firm Sales

Schedule Page: 310.3 Line No.: 11 Column: b

Financial Transmission Losses

Schedule Page: 310.3 Line No.: 12 Column: b

Non-firm Sales

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

Spinning or Operating Reserves

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

Non-firm Sales

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

Financial Transmission Losses

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

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

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

Non-firm Sales

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

ISDA Master Agreement with Sempra Energy Trading dated February 21, 2008.

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

Financial Transmission Losses

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

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

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

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 12 Column: b

Unit Contingent

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

Non-firm Sales

Schedule Page: 310.5 Line No.: 1 Column: b

Spinning or Operating Reserves

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

Financial Transmission Losses

Schedule Page: 310.5 Line No.: 4 Column: b

Non-firm Sales

Schedule Page: 310.5 Line No.: 5 Column: b

Financial Transmission Losses

Schedule Page: 310.5 Line No.: 7 Column: b

Financial Transmission Losses

Schedule Page: 310.5 Line No.: 9 Column: b

Non-firm Sales

Schedule Page: 310.5 Line No.: 11 Column: b

Financial Transmission Losses

Schedule Page: 310.5 Line No.: 12 Column: b

Non-firm Sales

Schedule Page: 310.6 Line No.: 2 Column: b

ISDA Master Agreement with Wells Fargo Bank, N.A. daed March 1, 2006

Schedule Page: 310.6 Line No.: 3 Column: b

December 2010 Adjustment

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	1,690,161	1,888,571
5	(501) Fuel	119,844,954	146,926,801
6	(502) Steam Expenses	6,950,410	7,337,561
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,231,309	2,140,193
10	(506) Miscellaneous Steam Power Expenses	9,734,263	9,797,755
11	(507) Rents	498,085	229,315
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	140,949,182	168,320,196
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,075,559	2,292,767
16	(511) Maintenance of Structures	920,609	309,374
17	(512) Maintenance of Boiler Plant	15,351,039	16,067,832
18	(513) Maintenance of Electric Plant	6,827,635	3,915,291
19	(514) Maintenance of Miscellaneous Steam Plant	6,486,063	3,753,015
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	31,660,905	26,338,279
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	172,610,087	194,658,475
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,380,371	5,362,099
45	(536) Water for Power	8,772,110	7,322,751
46	(537) Hydraulic Expenses	12,513,192	10,671,807
47	(538) Electric Expenses	1,611,582	1,565,842
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,081,121	2,895,723
49	(540) Rents	209,213	406,432
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	31,567,589	28,224,654
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,763,673	1,967,876
54	(542) Maintenance of Structures	1,722,862	1,155,653
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,563,284	1,368,190
56	(544) Maintenance of Electric Plant	1,789,947	3,177,811
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,719,281	3,029,473
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,559,047	10,699,003
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,126,636	38,923,657

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	820,192	328,417
63	(547) Fuel	11,696,917	12,745,952
64	(548) Generation Expenses	749,804	448,744
65	(549) Miscellaneous Other Power Generation Expenses	779,335	450,180
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	14,046,248	13,973,293
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		43
70	(552) Maintenance of Structures	179,520	182,043
71	(553) Maintenance of Generating and Electric Plant	115,128	118,533
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,861,365	1,077,264
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,156,013	1,377,883
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	16,202,261	15,351,176
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	156,873,749	137,850,336
77	(556) System Control and Load Dispatching	1,219	160
78	(557) Other Expenses	41,459,600	53,795,016
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	198,334,568	191,645,512
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	428,273,552	440,578,820
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,326,891	2,992,955
84	(561) Load Dispatching	192,086	273,869
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,188,357	1,254,735
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,423,636	1,316,482
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	102,697	108,008
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,252,352	1,987,214
94	(563) Overhead Lines Expenses	746,070	660,035
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,462,104	5,918,507
97	(566) Miscellaneous Transmission Expenses	307,899	336,835
98	(567) Rents	3,283,621	1,569,168
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,285,713	16,417,808
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	220,612	540,340
102	(569) Maintenance of Structures		195
103	(569.1) Maintenance of Computer Hardware	54,018	66,482
104	(569.2) Maintenance of Computer Software	347,776	324,033
105	(569.3) Maintenance of Communication Equipment	26,183	28,510
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,975,539	3,447,662
108	(571) Maintenance of Overhead Lines	3,675,361	2,781,256
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	5,474	-40
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,304,963	7,188,438
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	26,590,676	23,606,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	3,746,431	3,713,391
135	(581) Load Dispatching	3,482,055	3,419,960
136	(582) Station Expenses	1,192,869	1,277,818
137	(583) Overhead Line Expenses	3,039,224	3,029,340
138	(584) Underground Line Expenses	1,825,857	1,792,342
139	(585) Street Lighting and Signal System Expenses	122,065	79,537
140	(586) Meter Expenses	4,130,937	4,219,270
141	(587) Customer Installations Expenses	1,092,077	1,521,427
142	(588) Miscellaneous Expenses	5,494,553	5,004,179
143	(589) Rents	830,940	440,788
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,957,008	24,498,052
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	402,381	371,979
147	(591) Maintenance of Structures	5,711	-11,385
148	(592) Maintenance of Station Equipment	3,230,860	3,774,723
149	(593) Maintenance of Overhead Lines	14,495,482	14,297,636
150	(594) Maintenance of Underground Lines	1,054,033	1,003,405
151	(595) Maintenance of Line Transformers	433,841	448,157
152	(596) Maintenance of Street Lighting and Signal Systems	554,042	587,953
153	(597) Maintenance of Meters	472,599	700,080
154	(598) Maintenance of Miscellaneous Distribution Plant	252,535	137,583
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,901,484	21,310,131
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,858,492	45,808,183
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	427,283	410,702
160	(902) Meter Reading Expenses	2,453,647	4,026,937
161	(903) Customer Records and Collection Expenses	12,944,062	12,988,731
162	(904) Uncollectible Accounts	4,269,718	4,638,855
163	(905) Miscellaneous Customer Accounts Expenses	252	342
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	20,094,962	22,065,567

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	528,250	352,779
168	(908) Customer Assistance Expenses	44,034,548	51,959,849
169	(909) Informational and Instructional Expenses	82,775	31,517
170	(910) Miscellaneous Customer Service and Informational Expenses	531,823	864,003
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	45,177,396	53,208,148
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	67,143,039	63,660,597
182	(921) Office Supplies and Expenses	15,742,902	13,613,991
183	(Less) (922) Administrative Expenses Transferred-Credit	26,009,805	27,799,634
184	(923) Outside Services Employed	4,925,844	7,210,630
185	(924) Property Insurance	3,207,120	3,329,577
186	(925) Injuries and Damages	5,806,100	5,668,380
187	(926) Employee Pensions and Benefits	60,010,908	30,031,098
188	(927) Franchise Requirements		2,549
189	(928) Regulatory Commission Expenses	3,449,337	3,797,836
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	552,129	417,950
192	(930.2) Miscellaneous General Expenses	3,750,121	3,826,102
193	(931) Rents	7,103	12,600
194	TOTAL Operation (Enter Total of lines 181 thru 193)	138,584,798	103,771,676
195	Maintenance		
196	(935) Maintenance of General Plant	4,522,111	4,182,610
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	143,106,909	107,954,286
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	709,101,987	693,221,250

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	-	N/A	N/A	N/A
3	Allan Ravenscroft/Malad River	LU	-	.488		
4	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
5	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
6	Big Sky West Dairy Digester	LU	-	N/A	N/A	N/A
7	Big Wood Canal Company					
8	Black Canyon #3	LU	-	N/A	N/A	N/A
9	Jim Knight	LU	-	N/A	N/A	N/A
10	Sagebrush	LU	-	N/A	N/A	N/A
11	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
12	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
13	Burley Butte Wind Park	LU	-	N/A	N/A	N/A
14	Bypass Limited	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
							1
173				3,741		3,741	2
3,517			155,672	99,501		255,173	3
45,167				2,483,800		2,483,800	4
9,891				325,916		325,916	5
8,994				504,286		504,286	6
							7
336				22,007		22,007	8
1,323				89,760		89,760	9
1,329				90,187		90,187	10
5,504				498,646		498,646	11
793				54,831		54,831	12
45,701				1,880,363		1,880,363	13
27,866				1,494,916		1,494,916	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	-	N/A	N/A	N/A
2	Cargill Inc./B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
3	Cassia Gulch Wind Park	LU	-	N/A	N/A	N/A
4	Cassia Wind Farm	LU	-	N/A	N/A	N/A
5	City of Cove, Oregon/Mill Creek	LU	-	N/A	N/A	N/A
6	City of Hailey	LU	-	N/A	N/A	N/A
7	City of Pocatello	LU	-	N/A	N/A	N/A
8	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
9	Clifton E. Jenson/Birchcreek	LU	-	.05		
10	Consolidated Hydro Inc./Enel					
11	Barber Dam	LU	-	N/A	N/A	N/A
12	GeoBon #2	LU	-	N/A	N/A	N/A
13	Rock Creek #2	LU	-	N/A	N/A	N/A
14	Dietrich Drop	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
60,804				5,025,974		5,025,974	1
2,295				79,729		79,729	2
							3
24,118				1,079,424		1,079,424	4
327				25,893		25,893	5
58				4,046		4,046	6
1,532				110,715		110,715	7
3,490				294,206		294,206	8
342			17,500	9,669		27,169	9
							10
14,120				695,077		695,077	11
4,033				288,572		288,572	12
9,575				471,800		471,800	13
15,517				847,439		847,439	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Lowline #2	LU	-	N/A	N/A	N/A
2	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
3	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
4	Curry Cattle Company	LU	-	.084		
5	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
6	David R Snedigar	LU	-	N/A	N/A	N/A
7	D.R. Johnson Lumber/Co Gen Co	SF	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Fisheries Development	OS	-	N/A	N/A	N/A
10	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
11	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
12	Glenns Ferry Cogen Partners/Magic	LU	-	N/A	N/A	N/A
13	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
14	Hazelton B Power Company	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,689				520,129		520,129	1
5,022				333,058		333,058	2
11,237				764,612		764,612	3
584			26,796	16,532		43,328	4
816				11,516		11,516	5
1,539				105,819		105,819	6
10,048				976,820		976,820	7
3,139				238,020		238,020	8
1,087				15,461		15,461	9
24,732				1,214,017		1,214,017	10
23,680				1,357,141		1,357,141	11
-32				-16,371		-16,371	12
26,958				1,191,124		1,191,124	13
22,984				1,569,320		1,569,320	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
2	Horeshoe Bend Hydro	LU	-	N/A	N/A	N/A
3	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
4	Hot Springs Wind Farm	LU	-	N/A	N/A	N/A
5	Idaho Winds/Sawtooth Wind Project	LU	-	N/A	N/A	N/A
6	JR Simplot Co.	LU	-	N/A	N/A	N/A
7	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
8	James B. Howell/CHI Elk Creek	LU	-	N/A	N/A	N/A
9	John R LeMoyne	LU	-	N/A	N/A	N/A
10	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
11	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
12	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
13	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
14	Lime Wind	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	
1,615				116,960		116,960	1
41,991				2,788,304		2,788,304	2
20,582				1,003,804		1,003,804	3
44,465				2,454,028		2,454,028	4
12,376				933,162		933,162	5
77,631				4,454,339		4,454,339	6
1,422				80,643		80,643	7
4,026				298,796		298,796	8
633				35,123		35,123	9
3,276				251,302		251,302	10
3,841				313,305		313,305	11
9,205				599,368		599,368	12
1,486				113,045		113,045	13
288				24,468		24,468	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
2	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
3	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
4	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
5	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
6	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
7	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
8	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
9	Owyhee Irrigation District					
10	Mitchell Butte	LU	-	N/A	N/A	N/A
11	Owyhee Dam	LU	-	N/A	N/A	N/A
12	Tunnel #1	LU	-	N/A	N/A	N/A
13	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
14	Pigeon Cove Power	LU	-	1.389		
	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)	
6,631				423,980		423,980	1
8,737				619,500		619,500	2
28,257				1,469,468		1,469,468	3
3,502				233,621		233,621	4
57,414				3,696,680		3,696,680	5
39,112				1,790,027		1,790,027	6
459				31,240		31,240	7
33,718				1,382,867		1,382,867	8
							9
7,076				166,007		166,007	10
25,601				485,901		485,901	11
25,063				2,752,182		2,752,182	12
58,964				4,846,169		4,846,169	13
7,374			486,150	181,396		667,546	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
2	Pristine Springs Inc #3	LU	-	N/A	N/A	N/A
3	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
4	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
5	Richard Kaster					
6	Box Canyon	LU	-	N/A	N/A	N/A
7	Briggs Creek	LU	-	N/A	N/A	N/A
8	Rim View Trout Company	OS	-	N/A	N/A	N/A
9	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
10	Riverside Investments/Arena Drop	LU	-	N/A	N/A	N/A
11	Rock Creek #1 Joint Venture	LU	-	1.732		
12	Rockland Wind Project	LU	-	N/A	N/A	N/A
13	Rupert Cogen Partners/Magic Valley	LU	-	N/A	N/A	N/A
14	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
30,261				1,371,177		1,371,177	1
850				18,180		18,180	2
856				48,791		48,791	3
784				59,078		59,078	4
							5
1,664				109,773		109,773	6
3,715				248,306		248,306	7
1,173				17,307		17,307	8
4,692				279,049		279,049	9
1,458				106,175		106,175	10
10,247			552,508	289,896		842,404	11
24,934				1,101,093		1,101,093	12
79,969				5,012,242		5,012,242	13
21,263				820,346		820,346	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	SE Hazelton A LP	LU	-	N/A	N/A	N/A
2	Shorock Hydro Inc.					
3	Shoshone Cspp	LU	-	N/A	N/A	N/A
4	Shoshone #2	LU	-	N/A	N/A	N/A
5	Snake Rivery Pottery	LU	-	N/A	N/A	N/A
6	South Forks JointVenture/Lowline Canal	LU	-	N/A	N/A	N/A
7	Tamarack Energy Partnership	LU	-	4.942		
8	Tasco - Nampa	OS	-	N/A	N/A	N/A
9	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
10	Thousand Spring Wind Park	LU	-	N/A	N/A	N/A
11	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
12	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
13	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
14	White Water Ranch	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
23,842				1,224,987		1,224,987	1
							2
1,941				153,670		153,670	3
2,634				171,411		171,411	4
364				24,629		24,629	5
28,067				2,009,238		2,009,238	6
32,725			1,576,498	1,222,917		2,799,415	7
143				2,168		2,168	8
29,729				1,520,185		1,520,185	9
30,024				1,283,708		1,283,708	10
26,287				1,022,303		1,022,303	11
82,103				5,270,518		5,270,518	12
8,950				536,979		536,979	13
679				44,717		44,717	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
2	Willis and Betty Deveny/Shingle Creek	LU	-	N/A	N/A	N/A
3	Wilson Power Company	LU	-	N/A	N/A	N/A
4	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
5	New Wind Projects Scheduled Energy	LU	-	N/A	N/A	N/A
6	Other Purchased Power					
7	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
8	Avista Corp.	SF	T-12	N/A	N/A	N/A
9	Avista Corp.	SF	WSPP	N/A	N/A	N/A
10	Avista Corp.	OS	WSPP	N/A	N/A	N/A
11	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
12	Barclays Bank PLC	OS	-	N/A	N/A	N/A
13	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
14	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	
4,294				306,445		306,445	1
1,015				70,109		70,109	2
26,648				1,823,974		1,823,974	3
59,972				4,942,689		4,942,689	4
792							5
							6
26,690				994,099		994,099	7
24				738		738	8
3,369				89,845		89,845	9
					278,412	278,412	10
415				8,763		8,763	11
					43,340	43,340	12
4,102				124,785		124,785	13
					524,683	524,683	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
2	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
3	BP Energy Company	SF	WSPP	N/A	N/A	N/A
4	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
5	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
6	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
7	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
8	Citigroup Energy Inc.	OS	-	N/A	N/A	N/A
9	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
10	Constellation Energy Commodities Group	SF	WSPP	N/A	N/A	N/A
11	DB Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
12	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
13	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
14	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	
125,529				3,588,046		3,588,046	1
990				27,950		27,950	2
25,200				1,118,900		1,118,900	3
31,024				862,192		862,192	4
38,435				1,177,579		1,177,579	5
206				2,952		2,952	6
14,071				396,889		396,889	7
					163,244	163,244	8
427				3,574		3,574	9
1,722				56,342		56,342	10
3,200				85,128		85,128	11
1,601				40,036		40,036	12
3,350				91,601		91,601	13
537				8,000		8,000	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
2	Glendale Power Marketing	SF	WSPP	N/A	N/A	N/A
3	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
4	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
5	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
6	JPMorgan Chase Bank, N.A.	OS	-	N/A	N/A	N/A
7	Jefferies Bache	OS	-	N/A	N/A	N/A
8	Los Alamos County Utilities	SF	WSPP	N/A	N/A	N/A
9	Macquarie Cook Power Inc.	SF	WSPP	N/A	N/A	N/A
10	Macquarie Cook Power Inc.	OS	-	N/A	N/A	N/A
11	Morgan Stanley Capital Group Inc.	SF	V6-62	N/A	N/A	N/A
12	Morgan Stanley Capital Group Inc.	SF	V6-62	N/A	N/A	N/A
13	NaturEner USA, LLC	SF	WSPP	N/A	N/A	N/A
14	Nevada Power Co, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	
11,275				263,134		263,134	1
63				3,266		3,266	2
1,986				50,865		50,865	3
94,000				2,705,042		2,705,042	4
63,807				5,487,618		5,487,618	5
					572,658	572,658	6
					6,320,112	6,320,112	7
2							8
69,101				2,717,535		2,717,535	9
					72,038	72,038	10
3,252				56,697		56,697	11
90				3,600		3,600	12
1				36		36	13
200				9,000		9,000	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	NextEra Energy Power Marketing, LLC	SF	WSPP	N/A	N/A	N/A
2	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
3	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
4	PacifiCorp Inc.	SF	T-13	N/A	N/A	N/A
5	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
6	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
7	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
8	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
9	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
10	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
11	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
12	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
13	PPL EnergyPlus, LLC	IF	WSPP	N/A	N/A	N/A
14	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
	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)	
29,575				1,262,442		1,262,442	1
42				1,267		1,267	2
15				525		525	3
218				6,526		6,526	4
92				3,120		3,120	5
13,266				434,748		434,748	6
					139,138	139,138	7
42				1,270		1,270	8
37,330				826,882		826,882	9
50				900		900	10
31,577				1,382,689		1,382,689	11
630				29,185		29,185	12
103,584				9,555,624		9,555,624	13
50,783				1,351,475		1,351,475	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	Average Monthly CP Demand (f)
1	Public Service Company of New Mexico	SF	WSPP	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
3	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
4	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
5	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
6	San Diego Gas and Electric	SF	WSPP	N/A	N/A	N/A
7	Seattle City Light	SF	WSPP	N/A	N/A	N/A
8	Seattle City Light	SF	WSPP	N/A	N/A	N/A
9	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
10	Shell Energy North America (US), L.P.	OS	-	N/A	N/A	N/A
11	Sierra Pacific Power Co., dba NV Energ	SF	T-55	N/A	N/A	N/A
12	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
13	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
187				8,386		8,386	1
52				1,587		1,587	2
24,348				690,070		690,070	3
225				7,050		7,050	4
24,497				1,072,745		1,072,745	5
1				7		7	6
9,954				273,191		273,191	7
20				520		520	8
28,519				720,324		720,324	9
					112,078	112,078	10
22				669		669	11
9,039				305,532		305,532	12
5				24		24	13
					6,808	6,808	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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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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	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
2	Southern California Edison	SF	WSPP	N/A	N/A	N/A
3	Southwestern Public Service Company	SF	WSPP	N/A	N/A	N/A
4	Tacoma Power	SF	WSPP	N/A	N/A	N/A
5	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
6	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
8	Tri-State Generation and Transmission	SF	WSPP	N/A	N/A	N/A
9	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
10	Wells Fargo Authority, N.A.	OS	-	N/A	N/A	N/A
11	Western Area Power Administration	SF	WSPP	N/A	N/A	N/A
12	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
13	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
14	Net Metering Customers	OS	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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 (i) 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)	
4,492				114,955		114,955	1
6,579				183,947		183,947	2
248				4,359		4,359	3
2,168				75,276		75,276	4
2,598				78,536		78,536	5
2,448				79,171		79,171	6
40				560		560	7
90				9,000		9,000	8
145				1,576		1,576	9
					68,756	68,756	10
1				36		36	11
63,489				3,781,365		3,781,365	12
310,955				16,772,667		16,772,667	13
639				51,605		51,605	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Oregon Solar Customers	OS	-	N/A	N/A	N/A
2	Macquarie Energy LLC	AD	WSPP	N/A	N/A	N/A
3	Power Exchanges					
4	Benton Co Public Utility District #1	EX	-	-	-	-
5	Bonneville Power Administration	EX	-	-	-	-
6	NorthWestern Energy	EX	-	-	-	-
7	PacifiCorp Inc.	EX	-	-	-	-
8	Puget Sound Energy, Inc.	EX	-	-	-	-
9	Sierra Pacific Power Co., dba NV Energ	EX	-	-	-	-
10	Utah Associated Municipal Power System	EX	-	-	-	-
11	Clatskanie PUD	EX	153	-	-	-
12	Sierra Pacific Power Co., dba NV Energ	EX	WSPP	-	-	-
13	PacifiCorp Inc	EX	WSPP	-	-	-
14	Other Transactions					
	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	04/13/2012	End of 2011/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)	
106				3,375		3,375	1
50				2,000		2,000	2
							3
	1						4
	60,085						5
		2,946					6
	165,922	269,181					7
	18						8
		5,455					9
	24						10
	84,917	111,843					11
	228,424	228,424					12
	63,000	63,000					13
							14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Acct Valuation-Clatskanie PUD Exchange		-	-	-	-
2	Write-Off (Lehman Brothers)		-	-	-	-
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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	04/13/2012	End of 2011/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)	
					-716,681	-716,681	1
					-30,800	-30,800	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Schedule Page: 326 Line No.: 3 Column: e
Unavailable

Schedule Page: 326 Line No.: 3 Column: f
Unavailable

Schedule Page: 326.1 Line No.: 9 Column: e
Unavailable

Schedule Page: 326.1 Line No.: 9 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 4 Column: e
Unavailable

Schedule Page: 326.2 Line No.: 4 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 9 Column: b
Non Firm Purchases

Schedule Page: 326.2 Line No.: 12 Column: a
ISDA Master Agreement with Shell Energy North America dated November 1, 2009

Schedule Page: 326.2 Line No.: 14 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 5 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 14 Column: e
Unavailable

Schedule Page: 326.4 Line No.: 14 Column: f
Unavailable

Schedule Page: 326.5 Line No.: 8 Column: b
Non Firm Purchases

Schedule Page: 326.5 Line No.: 11 Column: e
Unavailable

Schedule Page: 326.5 Line No.: 11 Column: f
Unavailable

Schedule Page: 326.6 Line No.: 6 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

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

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

Schedule Page: 326.6 Line No.: 8 Column: b
Non Firm Purchases

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

Schedule Page: 326.7 Line No.: 5 Column: b
Energy scheduled in December 2010, booked in January 2011

Schedule Page: 326.7 Line No.: 10 Column: b
Financial Transmission Losses

Schedule Page: 326.7 Line No.: 12 Column: b
ISDA Master Agreement with Barclays Bank PLC dated March 2, 2011

Schedule Page: 326.7 Line No.: 14 Column: b
Financial Transmission Losses

Schedule Page: 326.8 Line No.: 2 Column: b
Non Firm Purchases

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Schedule Page: 326.8 Line No.: 8 Column: b
ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011
Schedule Page: 326.9 Line No.: 6 Column: b
ISDA Master Agreement with JP Morgan Chase Bank dated November 4, 2005
Schedule Page: 326.9 Line No.: 7 Column: b
Prudential Bache Commodities, LLC (Jefferies Bache) Futures Account Document, dated September 4, 2008
Schedule Page: 326.9 Line No.: 10 Column: b
ISDA Master Agreement with Macquarie Energy PLC dated April 12, 2011
Schedule Page: 326.9 Line No.: 12 Column: b
Non Firm Purchases
Schedule Page: 326.10 Line No.: 5 Column: b
Non Firm Purchases
Schedule Page: 326.10 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 326.11 Line No.: 4 Column: b
Non Firm Purchases
Schedule Page: 326.11 Line No.: 10 Column: b
ISDA Master Agreement with Shell Energy North America dated November 1, 2009
Schedule Page: 326.11 Line No.: 13 Column: b
Non Firm Purchases
Schedule Page: 326.11 Line No.: 14 Column: b
Financial Transmission Losses
Schedule Page: 326.12 Line No.: 10 Column: b
ISDA Master Agreement with Wells Fargo Bank, N.A., dated March 1, 2006
Schedule Page: 326.12 Line No.: 12 Column: b
Unavailable
Schedule Page: 326.12 Line No.: 14 Column: b
Schedule 84 Net Metering
Schedule Page: 326.13 Line No.: 1 Column: b
Schedule 88 Oregon Solar
Schedule Page: 326.13 Line No.: 2 Column: b
December 2010 adjustment
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
Schedule Page: 326.13 Line No.: 8 Column: b
Scheduled losses not removed with loss transactions
Schedule Page: 326.13 Line No.: 9 Column: b
Scheduled losses not removed with loss transactions
Schedule Page: 326.13 Line No.: 10 Column: b
Scheduled losses not removed with loss transactions

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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 - Raft	Bonneville Power Administration	Raft River Electric Co-op	FNO
4	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
5	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
6	Cargill	Seattle City Light	Bonneville Power Administration	OS
7	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
8	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
9	PacifiCorp	PacifiCorp West	PacifiCorp West	OS
10	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
12	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
13	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
14	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
15	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
16	BC Hydro Powerex	PacifiCorp East	Avista	NF
17	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
18	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
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	PacifiCorp East	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
23	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
24	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
27	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
29	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
31	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
32	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
33	BC Hydro Powerex	PacifiCorp East	Avista	NF
34	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	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	04/13/2012	End of 2011/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				368,297	368,297	1
5				189,508	189,508	2
5				205,046	205,046	3
5				907,088	907,088	4
Legacy	Minidoka, Idaho	Various in Idaho		8,322	8,322	5
10				388,704	388,704	6
5				2,094	2,094	7
Legacy	LaGrande, Oregon	Various in Idaho		14,238	14,238	8
Legacy	JBSN	ENPR				9
5	AVAT.NWMT	BORA		92	92	10
5	AVAT.NWMT	M345		30	30	11
5	BORA	BPAT.NWMT		855	855	12
5	BORA	BRDY		179	179	13
5	BORA	JBSN		490	490	14
5	BORA	LAGRANDE		9,866	9,866	15
5	BORA	LOLO		99	99	16
5	BORA	M345		3,546	3,546	17
5	BORA	M500		2,314	2,314	18
5	BPAT.NWMT	BORA		3,310	3,310	19
5	BPAT.NWMT	BORA		3,688	3,688	20
5	BPAT.NWMT	BRDY		2,380	2,380	21
5	BPAT.NWMT	BRDY		8,830	8,830	22
5	BPAT.NWMT	JBSN		95	95	23
5	BPAT.NWMT	LAGRANDE		397	397	24
5	BPAT.NWMT	M345		664	664	25
5	BPAT.NWMT	M345		18,792	18,792	26
5	BRDY	AVAT.NWMT		102	102	27
5	BRDY	BORA		260	260	28
5	BRDY	BPAT.NWMT		154	154	29
5	BRDY	ENPR		80	80	30
5	BRDY	JBSN		90	90	31
5	BRDY	LAGRANDE		14,347	14,347	32
5	BRDY	LOLO		10	10	33
5	BRDY	M345		2,386	2,386	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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 East	Sierra Pacific Power	SFP
2	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
3	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
4	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
5	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
6	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
7	BC Hydro Powerex	PacifiCorp West	PacifiCorp West	NF
8	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
9	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	SFP
10	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
11	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
12	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
13	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
14	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
15	BC Hydro Powerex	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
16	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
17	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
18	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
19	BC Hydro Powerex	Idaho Power Company	NorthWestern/PacifiCorp East	NF
20	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
21	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
22	BC Hydro Powerex	PacifiCorp West	NorthWestern/PacifiCorp East	NF
23	BC Hydro Powerex	PacifiCorp West	Bonneville Power Administration	NF
24	BC Hydro Powerex	PacifiCorp West	Sierra Pacific Power	NF
25	BC Hydro Powerex	Idaho Power Company	PacifiCorp East	NF
26	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
27	BC Hydro Powerex	Idaho Power Company	PacifiCorp West	NF
28	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
30	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
31	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
32	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
33	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	BRDY	M345		1,848	1,848	1
5	BRDY	M500		1,281	1,281	2
5	ENPR	BORA		219,615	219,615	3
5	ENPR	BORA		1,433	1,433	4
5	ENPR	BRDY		19,008	19,008	5
5	ENPR	BRDY		3,642	3,642	6
5	ENPR	JBSN		211	211	7
5	ENPR	M345		1,127	1,127	8
5	ENPR	M345		32	32	9
5	GSHN	AVAT.NWMT		10	10	10
5	GSHN	BPAT.NWMT		523	523	11
5	GSHN	BRDY		667	667	12
5	GSHN	ENPR		83	83	13
5	GSHN	JBSN		544	544	14
5	GSHN	JEFF		35	35	15
5	GSHN	LAGRANDE		10,167	10,167	16
5	GSHN	M345		579	579	17
5	GSHN	M500		796	796	18
5	HCPR	BPAT.NWMT		149	149	19
5	HCPR	LAGRANDE		3,056	3,056	20
5	JBSN	BORA		20	20	21
5	JBSN	BPAT.NWMT		36	36	22
5	JBSN	LAGRANDE		2,947	2,947	23
5	JBSN	M345		138	138	24
5	JBWT	BORA		35	35	25
5	JBWT	LAGRANDE		1,448	1,448	26
5	JBWT	M500		127	127	27
5	JEFF	BORA		6,317	6,317	28
5	JEFF	BRDY		746	746	29
5	JEFF	ENPR		53	53	30
5	JEFF	JBSN		88	88	31
5	JEFF	LAGRANDE		400	400	32
5	JEFF	M345		103	103	33
5	LAGRANDE	BORA		54,378	54,378	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	SFP
2	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	NF
3	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp East	SFP
4	BC Hydro Powerex	Bonneville Power Administration	PacifiCorp West	NF
5	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	NF
6	BC Hydro Powerex	Bonneville Power Administration	Sierra Pacific Power	SFP
7	BC Hydro Powerex	Avista	PacifiCorp East	NF
8	BC Hydro Powerex	Avista	PacifiCorp East	NF
9	BC Hydro Powerex	Avista	PacifiCorp West	NF
10	BC Hydro Powerex	Avista	Sierra Pacific Power	NF
11	BC Hydro Powerex	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
12	BC Hydro Powerex	Sierra Pacific Power	PacifiCorp East	NF
13	BC Hydro Powerex	Sierra Pacific Power	Bonneville Power Administration	NF
14	BC Hydro Powerex	Idaho Power Company	NorthWestern/PacifiCorp East	NF
15	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
16	BC Hydro Powerex	Idaho Power Company	NorthWestern/PacifiCorp East	NF
17	BC Hydro Powerex	Idaho Power Company	Bonneville Power Administration	NF
18	Black Hills Power	PacifiCorp East	Sierra Pacific Power	NF
19	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
20	Black Hills Power	Bonneville Power Administration	PacifiCorp East	NF
21	Black Hills Power	Bonneville Power Administration	PacifiCorp West	NF
22	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
23	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
24	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
25	Bonneville Power Administration	Avista	Bonneville Power Administration	SFP
26	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
27	Cargill-Alliant	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Cargill-Alliant	PacifiCorp East	NorthWestern/PacifiCorp East	NF
29	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
30	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
31	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	NF
32	Cargill-Alliant	PacifiCorp East	Avista	NF
33	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	NF
34	Cargill-Alliant	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) 04/13/2012	Year/Period of Report End of 2011/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		799	799	1
5	LAGRANDE	BRDY		12,461	12,461	2
5	LAGRANDE	BRDY		2,482	2,482	3
5	LAGRANDE	JBSN		1,847	1,847	4
5	LAGRANDE	M345		11,056	11,056	5
5	LAGRANDE	M345		373	373	6
5	LOLO	BORA		11,424	11,424	7
5	LOLO	BRDY		1,165	1,165	8
5	LOLO	JBSN		168	168	9
5	LOLO	M345		3,569	3,569	10
5	M345	BPAT.NWMT		132	132	11
5	M345	BRDY		80	80	12
5	M345	LAGRANDE		2,001	2,001	13
5	MDSK	BPAT.NWMT		175	175	14
5	MDSK	LAGRANDE		1,272	1,272	15
5	OBBLPR	BPAT.NWMT		204	204	16
5	OBBLPR	LAGRANDE		1,738	1,738	17
5	BORA	M345		2,250	2,250	18
5	JBSN	LAGRANDE		10	10	19
5	LAGRANDE	BORA		25	25	20
5	LAGRANDE	JBSN		60	60	21
5	LAGRANDE	LAGRANDE		3,005	3,005	22
5	LAGRANDE	M345		1,542	1,542	23
5	LOLO	LAGRANDE		7,115	7,115	24
5	LOLO	LAGRANDE		768	768	25
5	LOLO	M345		324	324	26
5	BORA	AVAT.NWMT		525	525	27
5	BORA	BPAT.NWMT		1,420	1,420	28
5	BORA	ENPR		820	820	29
5	BORA	JBSN		996	996	30
5	BORA	LAGRANDE		10,089	10,089	31
5	BORA	LOLO		249	249	32
5	BORA	M345		8,416	8,416	33
5	BORA	M345		4,153	4,153	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
3	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	NF
4	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp West	NF
5	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
6	Cargill-Alliant	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
7	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
8	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
9	Cargill-Alliant	PacifiCorp East	PacifiCorp East	NF
10	Cargill-Alliant	PacifiCorp East	PacifiCorp East	SFP
11	Cargill-Alliant	PacifiCorp East	PacifiCorp West	NF
12	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	NF
13	Cargill-Alliant	PacifiCorp East	Bonneville Power Administration	SFP
14	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	NF
15	Cargill-Alliant	PacifiCorp East	Sierra Pacific Power	SFP
16	Cargill-Alliant	PacifiCorp West	PacifiCorp East	NF
17	Cargill-Alliant	PacifiCorp West	PacifiCorp East	SFP
18	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	NF
19	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	SFP
20	Cargill-Alliant	Idaho Power Company	PacifiCorp East	SFP
21	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	NF
22	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	SFP
23	Cargill-Alliant	PacifiCorp West	NorthWestern/PacifiCorp East	NF
24	Cargill-Alliant	PacifiCorp West	Bonneville Power Administration	NF
25	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	NF
26	Cargill-Alliant	PacifiCorp West	Sierra Pacific Power	SFP
27	Cargill-Alliant	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
28	Cargill-Alliant	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
29	Cargill-Alliant	Bonneville Power Administration	PacifiCorp East	NF
30	Cargill-Alliant	Bonneville Power Administration	PacifiCorp East	SFP
31	Cargill-Alliant	Bonneville Power Administration	PacifiCorp West	NF
32	Cargill-Alliant	Bonneville Power Administration	Avista	NF
33	Cargill-Alliant	Bonneville Power Administration	Sierra Pacific Power	NF
34	Cargill-Alliant	Bonneville Power Administration	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) 04/13/2012	Year/Period of Report End of 2011/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	BPAT.NWMT	BORA		2,651	2,651	1
5	BPAT.NWMT	BORA		33,899	33,899	2
5	BPAT.NWMT	BRDY		25	25	3
5	BPAT.NWMT	JBSN		440	440	4
5	BPAT.NWMT	JBSN		1,200	1,200	5
5	BPAT.NWMT	LAGRANDE		5	5	6
5	BPAT.NWMT	M345		2,791	2,791	7
5	BPAT.NWMT	M345		43,719	43,719	8
5	BRDY	BORA		322	322	9
5	BRDY	BORA		504	504	10
5	BRDY	ENPR		63	63	11
5	BRDY	LAGRANDE		112	112	12
5	BRDY	LAGRANDE		600	600	13
5	BRDY	M345		932	932	14
5	BRDY	M345		64	64	15
5	ENPR	BORA		69,699	69,699	16
5	ENPR	BORA		60,810	60,810	17
5	ENPR	M345		8,765	8,765	18
5	ENPR	M345		1,392	1,392	19
5	HCPR	BORA		400	400	20
5	HCPR	M345		800	800	21
5	HCPR	M345		1,600	1,600	22
5	JBSN	BPAT.NWMT		3,200	3,200	23
5	JBSN	LAGRANDE		148	148	24
5	JBSN	M345		592	592	25
5	JBSN	M345		408	408	26
5	JEFF	BORA		320	320	27
5	JEFF	M345		928	928	28
5	LAGRANDE	BORA		2,346	2,346	29
5	LAGRANDE	BORA		1,454	1,454	30
5	LAGRANDE	JBSN		306	306	31
5	LAGRANDE	LOLO		238	238	32
5	LAGRANDE	M345		11,482	11,482	33
5	LAGRANDE	M345		17,606	17,606	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Avista	PacifiCorp East	NF
2	Cargill-Alliant	Avista	Sierra Pacific Power	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	NorthWestern/PacifiCorp East	NF
6	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
7	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
8	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	NF
9	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	SFP
10	Cargill-Alliant	Sierra Pacific Power	Avista	NF
11	Cargill-Alliant	Sierra Pacific Power	Avista	SFP
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	Bonneville Power Administration	NF
15	Cargill-Alliant	Idaho Power Company	Avista	NF
16	Cargill-Alliant	Idaho Power Company	PacifiCorp East	NF
17	Cargill-Alliant	Idaho Power Company	PacifiCorp East	SFP
18	Cargill-Alliant	Idaho Power Company	Bonneville Power Administration	NF
19	Cargill-Alliant	Idaho Power Company	Bonneville Power Administration	SFP
20	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	NF
21	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	SFP
22	Citigroup Energy			NF
23	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
24	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
25	Iberdrola Energy	PacifiCorp East	Sierra Pacific Power	NF
26	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
27	Iberdrola Energy	Bonneville Power Administration	Sierra Pacific Power	NF
28	Iberdrola Energy	Avista	Sierra Pacific Power	NF
29	Iberdrola Energy	Sierra Pacific Power	Bonneville Power Administration	NF
30	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
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	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	04/13/2012	End of 2011/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	LOLO	BORA		1,142	1,142	1
5	LOLO	M345		5,988	5,988	2
5	LYPK	BORA		10,724	10,724	3
5	LYPK	BORA		37,726	37,726	4
5	LYPK	BPAT.NWMT		1,563	1,563	5
5	LYPK	BRDY		667	667	6
5	LYPK	JEFF		173	173	7
5	LYPK	LAGRANDE		14,243	14,243	8
5	LYPK	LAGRANDE		1,664	1,664	9
5	LYPK	LOLO		100	100	10
5	LYPK	LOLO		200	200	11
5	LYPK	M345		64,772	64,772	12
5	LYPK	M345		243,254	243,254	13
5	M345	LAGRANDE		275	275	14
5	MDSK	LOLO		200	200	15
5	OBBLPR	BORA		1,000	1,000	16
5	OBBLPR	BORA		1,000	1,000	17
5	OBBLPR	LAGRANDE		410	410	18
5	OBBLPR	LAGRANDE		1,808	1,808	19
5	OBBLPR	M345		320	320	20
5	OBBLPR	M345		480	480	21
5						22
5	BORA	LAGRANDE		361	361	23
5	BRDY	LAGRANDE		57	57	24
5	BRDY	M345		24	24	25
5	LAGRANDE	BORA		5,027	5,027	26
5	LAGRANDE	M345		4,104	4,104	27
5	LOLO	M345		380	380	28
5	M345	LAGRANDE		381	381	29
5	AVAT.NWMT	BORA		544	544	30
5	AVAT.NWMT	BRDY		140	140	31
5	AVAT.NWMT	LAGRANDE		132	132	32
5	AVAT.NWMT	M345		3,663	3,663	33
5	BORA	LAGRANDE		66	66	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	PacifiCorp East	Sierra Pacific Power	NF
2	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
4	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
5	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
6	Morgan Stanley Capital Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
7	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp East	NF
8	Morgan Stanley Capital Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
9	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp West	NF
10	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
11	Morgan Stanley Capital Group	PacifiCorp East	Avista	NF
12	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
13	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	SFP
14	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp East	NF
15	Morgan Stanley Capital Group	PacifiCorp West	Sierra Pacific Power	NF
16	Morgan Stanley Capital Group	PacifiCorp West	Bonneville Power Administration	NF
17	Morgan Stanley Capital Group	PacifiCorp West	Sierra Pacific Power	NF
18	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
19	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp West	NF
21	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Avista	NF
23	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
24	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp East	NF
25	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp East	NF
26	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp West	NF
27	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp West	NF
28	Morgan Stanley Capital Group	Bonneville Power Administration	Sierra Pacific Power	NF
29	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
30	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
31	Morgan Stanley Capital Group	Avista	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group	Avista	Sierra Pacific Power	NF
33	Morgan Stanley Capital Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
34	Morgan Stanley Capital Group	Sierra Pacific Power	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	BORA	M345		8,522	8,522	1
5	BPAT.NWMT	BORA		371	371	2
5	BPAT.NWMT	BRDY		1,237	1,237	3
5	BPAT.NWMT	LAGRANDE		210	210	4
5	BPAT.NWMT	M345		756	756	5
5	BRDY	AVAT.NWMT		46	46	6
5	BRDY	BORA		62	62	7
5	BRDY	BPAT.NWMT		119	119	8
5	BRDY	JBSN		99	99	9
5	BRDY	LAGRANDE		19,275	19,275	10
5	BRDY	LOLO		100	100	11
5	BRDY	M345		8,148	8,148	12
5	BRDY	M345		1,981	1,981	13
5	ENPR	BRDY		1,128	1,128	14
5	ENPR	M345		180	180	15
5	JBSN	LAGRANDE		20	20	16
5	JBSN	M345		29	29	17
5	JEFF	BORA		5,996	5,996	18
5	JEFF	BRDY		6,680	6,680	19
5	JEFF	JBSN		250	250	20
5	JEFF	LAGRANDE		5,698	5,698	21
5	JEFF	LOLO		60	60	22
5	JEFF	M345		21,705	21,705	23
5	LAGRANDE	BORA		3,085	3,085	24
5	LAGRANDE	BRDY		8,183	8,183	25
5	LAGRANDE	ENPR		5	5	26
5	LAGRANDE	JBSN		65	65	27
5	LAGRANDE	M345		2,075	2,075	28
5	LOLO	BORA		2,335	2,335	29
5	LOLO	BRDY		2,292	2,292	30
5	LOLO	LAGRANDE		411	411	31
5	LOLO	M345		1,983	1,983	32
5	M345	JEFF		114	114	33
5	M345	LAGRANDE		1,597	1,597	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Noble Americas			NF
2	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
3	Pacificorp Power Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
4	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
5	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	LFP
6	Pacificorp Power Marketing	PacifiCorp East	Bonneville Power Administration	NF
7	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
8	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
9	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
10	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
11	Pacificorp Power Marketing	PacifiCorp West	Bonneville Power Administration	NF
12	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
13	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
14	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
15	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
16	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
17	Pacificorp Power Marketing	Idaho Power Company	Bonneville Power Administration	NF
18	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	LFP
19	Pacificorp Power Marketing	Bonneville Power Administration	PacifiCorp East	NF
20	Pacificorp Power Marketing	Avista	PacifiCorp East	NF
21	Pacificorp Power Marketing	Avista	PacifiCorp West	NF
22	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
23	PPL Energy Plus	PacifiCorp East	PacifiCorp East	NF
24	PPL Energy Plus	PacifiCorp East	PacifiCorp West	NF
25	PPL Energy Plus	PacifiCorp East	Bonneville Power Administration	NF
26	PPL Energy Plus	PacifiCorp East	Avista	NF
27	PPL Energy Plus	NorthWestern/PacifiCorp East	PacifiCorp East	NF
28	PPL Energy Plus	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	PPL Energy Plus	NorthWestern/PacifiCorp East	PacifiCorp West	NF
30	PPL Energy Plus	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
31	PPL Energy Plus	Bonneville Power Administration	PacifiCorp East	NF
32	PPL Energy Plus	Bonneville Power Administration	PacifiCorp East	NF
33	PPL Energy Plus	Bonneville Power Administration	PacifiCorp West	NF
34	PPL Energy Plus	Avista	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	0	0				1
5	BORA	ENPR		8,014	8,014	2
5	BORA	GSHN		3,740	3,740	3
5	BORA	KPRT		390,968	390,968	4
5	BORA	KPRT		403,551	403,551	5
5	BORA	LAGRANDE		1,621	1,621	6
5	BORA	M345		2,285	2,285	7
5	BORA	M345		4,032	4,032	8
5	BRDY	BRDY		1,616	1,616	9
5	ENPR	BORA		29,752	29,752	10
5	ENPR	LAGRANDE		682	682	11
5	JBSN	BORA		2,675	2,675	12
5	JBWT	BORA		61,027	61,027	13
5	JBWT	BRDY		54,685	54,685	14
5	JBWT	BRDY		381,175	381,175	15
5	JBWT	ENPR		1,153	1,153	16
5	JBWT	LAGRANDE		4,211	4,211	17
5	JBWT	M500		906,776	906,776	18
5	LAGRANDE	BORA		37,083	37,083	19
5	LOLO	BORA		95,641	95,641	20
5	LOLO	ENPR		921	921	21
5	JEFF	LAGRANDE		580	580	22
5	BRDY	BORA		724	724	23
5	BRDY	JBSN		150	150	24
5	BRDY	LAGRANDE		5,514	5,514	25
5	BRDY	LOLO		964	964	26
5	JEFF	BORA		79	79	27
5	JEFF	BRDY		2,086	2,086	28
5	JEFF	JBSN		420	420	29
5	JEFF	LAGRANDE		1,259	1,259	30
5	LAGRANDE	BORA		526	526	31
5	LAGRANDE	BRDY		216	216	32
5	LAGRANDE	JBSN		60	60	33
5	LOLO	BORA		495	495	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Avista	PacifiCorp East	NF
2	PPL Energy Plus	Avista	Bonneville Power Administration	NF
3	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF
4	Puget Sound Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
5	Puget Sound Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Puget Sound Energy	Bonneville Power Administration	Sierra Pacific Power	NF
7	Puget Sound Energy	Avista	Idaho Power Company	NF
8	Rainbow Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
9	Rainbow Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
11	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
12	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
13	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	SFP
14	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	NF
15	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	SFP
16	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	SFP
17	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
19	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
21	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
23	Rainbow Energy Marketing	Avista	PacifiCorp East	NF
24	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
25	Rainbow Energy Marketing	Avista	PacifiCorp East	NF
26	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
27	Rainbow Energy Marketing	Avista	Sierra Pacific Power	NF
28	Rainbow Energy Marketing	Avista	Sierra Pacific Power	SFP
29	Rainbow Energy Marketing	Idaho Power Company	PacifiCorp East	NF
30	Seattle City Light			LFP
31	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
32	Shell Energy	PacifiCorp East	PacifiCorp East	NF
33	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
34	Shell Energy	PacifiCorp East	Sierra Pacific Power	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	04/13/2012	End of 2011/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LOLO	BRDY		150	150	1
5	LOLO	LAGRANDE		937	937	2
5	BRDY	LAGRANDE		180	180	3
5	GSHN	LAGRANDE		155	155	4
5	JEFF	LAGRANDE		15	15	5
5	LAGRANDE	M345		134	134	6
5	LOLO	IPCOLOSS		1	1	7
5	BORA	AVAT.NWMT		200	200	8
5	BORA	JEFF		800	800	9
5	BPAT.NWMT	BORA		13,760	13,760	10
5	BPAT.NWMT	BRDY		16,074	16,074	11
5	BRDY	M345		172	172	12
5	BRDY	M345		2,081	2,081	13
5	ENPR	BRDY		1,623	1,623	14
5	ENPR	BRDY		348	348	15
5	JBSN	BRDY		1,568	1,568	16
5	JEFF	BORA		7,980	7,980	17
5	JEFF	BORA		8,109	8,109	18
5	JEFF	BRDY		40	40	19
5	JEFF	BRDY		4,093	4,093	20
5	JEFF	M345		505	505	21
5	JEFF	M345		23,673	23,673	22
5	LOLO	BORA		9,934	9,934	23
5	LOLO	BORA		2,501	2,501	24
5	LOLO	BRDY		3,017	3,017	25
5	LOLO	BRDY		1,050	1,050	26
5	LOLO	M345		400	400	27
5	LOLO	M345		2,250	2,250	28
5	OBBLPR	BRDY		400	400	29
5	0	0				30
5	BORA	LAGRANDE		25	25	31
5	BRDY	BORA		192	192	32
5	BRDY	LAGRANDE		5,375	5,375	33
5	BRDY	M345		468	468	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	Shell Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	Shell Energy	Bonneville Power Administration	PacifiCorp East	NF
4	Shell Energy	Bonneville Power Administration	Sierra Pacific Power	NF
5	Shell Energy	Avista	PacifiCorp East	NF
6	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
7	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
8	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
9	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
10	Shell Energy	Sierra Pacific Power	PacifiCorp East	NF
11	Shell Energy	Sierra Pacific Power	Bonneville Power Administration	NF
12	Shell Energy	Sierra Pacific Power	Avista	NF
13	Shell Energy	Idaho Power Company	PacifiCorp East	NF
14	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
15	Shell Energy	Idaho Power Company	Avista	NF
16	Shell Energy	Idaho Power Company	PacifiCorp East	NF
17	Shell Energy	Idaho Power Company	Bonneville Power Administration	NF
18	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
19	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
20	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
21	Sierra Pacific Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
22	Sierra Pacific Power Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	Sierra Pacific Power Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
24	Sierra Pacific Power Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
25	Sierra Pacific Power Marketing	Bonneville Power Administration	Sierra Pacific Power	SFP
26	Sierra Pacific Power Marketing	Avista	PacifiCorp East	NF
27	Sierra Pacific Power Marketing	Avista	Sierra Pacific Power	NF
28	Sierra Pacific Power Marketing	Avista	Sierra Pacific Power	SFP
29	Sierra Pacific Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
30	Sierra Pacific Power Marketing	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
31	Sierra Pacific Power Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
32	Sierra Pacific Power Marketing	Sierra Pacific Power	Avista	NF
33	Southern California Edison	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34	Tenaska	NorthWestern/PacifiCorp East	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	JEFF	BORA		200	200	1
5	JEFF	LAGRANDE		77	77	2
5	LAGRANDE	BORA		13	13	3
5	LAGRANDE	M345		2,231	2,231	4
5	LOLO	BORA		25	25	5
5	LYPK	BORA		12	12	6
5	LYPK	BRDY		50	50	7
5	LYPK	LAGRANDE		174	174	8
5	M345	BORA		180	180	9
5	M345	BRDY		100	100	10
5	M345	LAGRANDE		3,533	3,533	11
5	M345	LOLO		68	68	12
5	MDSK	BORA		400	400	13
5	MDSK	LAGRANDE		541	541	14
5	MDSK	LOLO		17	17	15
5	OBBLPR	BORA		300	300	16
5	OBBLPR	LAGRANDE		67	67	17
5	BORA	M345		6,360	6,360	18
5	BORA	M345		9,140	9,140	19
5	BRDY	M345		11,800	11,800	20
5	BRDY	M345		31,608	31,608	21
5	JEFF	M345		42,409	42,409	22
5	JEFF	M345		11,141	11,141	23
5	LAGRANDE	M345		34,496	34,496	24
5	LAGRANDE	M345		4,325	4,325	25
5	LOLO	BORA		48	48	26
5	LOLO	M345		35,267	35,267	27
5	LOLO	M345		7,424	7,424	28
5	M345	BORA		1,082	1,082	29
5	M345	JEFF		185	185	30
5	M345	LAGRANDE		3,458	3,458	31
5	M345	LOLO		225	225	32
5	GSHN	LAGRANDE		125	125	33
5	AVAT.NWMT	BRDY		95	95	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Tenaska	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	Tenaska	Bonneville Power Administration	PacifiCorp East	NF
3	Tenaska	Bonneville Power Administration	PacifiCorp East	NF
4	Tenaska	Bonneville Power Administration	PacifiCorp West	NF
5	The Energy Authority	PacifiCorp East	Bonneville Power Administration	NF
6	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
7	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
10	Transalta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
12	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
13	Transalta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
14	Transalta Energy Marketing	Avista	PacifiCorp East	NF
15	Transalta Energy Marketing	Avista	PacifiCorp East	NF
16	Transalta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
17	Transalta Energy Marketing	Idaho Power Company	PacifiCorp East	NF
18	Transalta Energy Marketing	Idaho Power Company	Bonneville Power Administration	NF
19	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5	BPAT.NWMT	BRDY		398	398	1
5	LAGRANDE	BORA		1,274	1,274	2
5	LAGRANDE	BRDY		1,290	1,290	3
5	LAGRANDE	JBSN		265	265	4
5	BRDY	LAGRANDE		30	30	5
5	BORA	LAGRANDE		706	706	6
5	BPAT.NWMT	BORA		25	25	7
5	BPAT.NWMT	BRDY		75	75	8
5	BRDY	LAGRANDE		300	300	9
5	JEFF	BORA		25	25	10
5	LAGRANDE	BORA		6,588	6,588	11
5	LAGRANDE	BRDY		1,066	1,066	12
5	LAGRANDE	M345		488	488	13
5	LOLO	BORA		513	513	14
5	LOLO	BRDY		28	28	15
5	M345	LAGRANDE		398	398	16
5	OBBLPR	BORA		50	50	17
5	OBBLPR	LAGRANDE		48	48	18
5	BORA	M345		648	648	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	6,092,216	6,092,216	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
1,414,450	39,800		1,454,250	1
1,163,226	201,793		1,365,019	2
535,470	18,160		553,630	3
3,193,659	-205,841		2,987,818	4
	13,482		13,482	5
	208,649		208,649	6
7,475	1,362		8,837	7
54,639			54,639	8
	2,395		2,395	9
	387		387	10
	126		126	11
	3,601		3,601	12
	754		754	13
	2,064		2,064	14
	41,551		41,551	15
	417		417	16
	14,934		14,934	17
	9,745		9,745	18
	13,940		13,940	19
	15,532		15,532	20
	10,023		10,023	21
	37,188		37,188	22
	400		400	23
	1,672		1,672	24
	2,796		2,796	25
	79,143		79,143	26
	430		430	27
	1,095		1,095	28
	649		649	29
	337		337	30
	379		379	31
	60,423		60,423	32
	42		42	33
	10,049		10,049	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	7,783		7,783	1
	5,395		5,395	2
	924,914		924,914	3
	6,035		6,035	4
	80,053		80,053	5
	15,338		15,338	6
	889		889	7
	4,746		4,746	8
	135		135	9
	42		42	10
	2,203		2,203	11
	2,809		2,809	12
	350		350	13
	2,291		2,291	14
	147		147	15
	42,819		42,819	16
	2,438		2,438	17
	3,352		3,352	18
	628		628	19
	12,870		12,870	20
	84		84	21
	152		152	22
	12,411		12,411	23
	581		581	24
	147		147	25
	6,098		6,098	26
	535		535	27
	26,604		26,604	28
	3,142		3,142	29
	223		223	30
	371		371	31
	1,685		1,685	32
	434		434	33
	229,014		229,014	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
	3,365		3,365	1
	52,480		52,480	2
	10,453		10,453	3
	7,779		7,779	4
	46,563		46,563	5
	1,571		1,571	6
	48,112		48,112	7
	4,906		4,906	8
	708		708	9
	15,031		15,031	10
	556		556	11
	337		337	12
	8,427		8,427	13
	737		737	14
	5,357		5,357	15
	859		859	16
	7,320		7,320	17
	5,535		5,535	18
	25		25	19
	61		61	20
	148		148	21
	12,137		12,137	22
	6,228		6,228	23
	28,738		28,738	24
	3,102		3,102	25
	1,309		1,309	26
	312		312	27
	844		844	28
	487		487	29
	592		592	30
	5,998		5,998	31
	148		148	32
	5,003		5,003	33
	2,469		2,469	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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.
	1,576		1,576	1
	20,153		20,153	2
	15		15	3
	262		262	4
	713		713	5
	3		3	6
	1,659		1,659	7
	25,991		25,991	8
	191		191	9
	300		300	10
	37		37	11
	67		67	12
	357		357	13
	554		554	14
	38		38	15
	41,436		41,436	16
	36,151		36,151	17
	5,211		5,211	18
	828		828	19
	238		238	20
	476		476	21
	951		951	22
	1,902		1,902	23
	88		88	24
	352		352	25
	243		243	26
	190		190	27
	552		552	28
	1,395		1,395	29
	864		864	30
	182		182	31
	141		141	32
	6,826		6,826	33
	10,467		10,467	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
	679		679	1
	3,560		3,560	2
	6,375		6,375	3
	22,428		22,428	4
	929		929	5
	397		397	6
	103		103	7
	8,467		8,467	8
	989		989	9
	59		59	10
	119		119	11
	38,507		38,507	12
	144,613		144,613	13
	163		163	14
	119		119	15
	594		594	16
	594		594	17
	244		244	18
	1,075		1,075	19
	190		190	20
	285		285	21
	4		4	22
	1,246		1,246	23
	197		197	24
	83		83	25
	17,356		17,356	26
	14,169		14,169	27
	1,312		1,312	28
	1,315		1,315	29
	1,937		1,937	30
	498		498	31
	470		470	32
	13,042		13,042	33
	235		235	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
	30,342		30,342	1
	1,321		1,321	2
	4,404		4,404	3
	748		748	4
	2,692		2,692	5
	164		164	6
	221		221	7
	424		424	8
	352		352	9
	68,628		68,628	10
	356		356	11
	29,011		29,011	12
	7,053		7,053	13
	4,016		4,016	14
	641		641	15
	71		71	16
	103		103	17
	21,348		21,348	18
	23,784		23,784	19
	890		890	20
	20,287		20,287	21
	214		214	22
	77,280		77,280	23
	10,984		10,984	24
	29,135		29,135	25
	18		18	26
	231		231	27
	7,388		7,388	28
	8,314		8,314	29
	8,161		8,161	30
	1,463		1,463	31
	7,060		7,060	32
	406		406	33
	5,686		5,686	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
	4		4	1
	27,861		27,861	2
	13,002		13,002	3
	1,359,206		1,359,206	4
				5
	5,635		5,635	6
	7,944		7,944	7
	14,017		14,017	8
	5,618		5,618	9
	103,433		103,433	10
	2,371		2,371	11
	9,300		9,300	12
	212,161		212,161	13
	190,113		190,113	14
	1,325,161		1,325,161	15
	4,008		4,008	16
	14,640		14,640	17
	3,152,421		3,152,421	18
	128,920		128,920	19
	332,497		332,497	20
	3,202		3,202	21
	1,311		1,311	22
	2,275		2,275	23
	471		471	24
	17,329		17,329	25
	3,030		3,030	26
	248		248	27
	6,556		6,556	28
	1,320		1,320	29
	3,957		3,957	30
	1,653		1,653	31
	679		679	32
	189		189	33
	1,556		1,556	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
	471		471	1
	2,945		2,945	2
	2,137		2,137	3
	1,841		1,841	4
	178		178	5
	1,591		1,591	6
	12		12	7
	513		513	8
	2,052		2,052	9
	35,296		35,296	10
	41,232		41,232	11
	441		441	12
	5,338		5,338	13
	4,163		4,163	14
	893		893	15
	4,022		4,022	16
	20,470		20,470	17
	20,801		20,801	18
	103		103	19
	10,499		10,499	20
	1,295		1,295	21
	60,724		60,724	22
	25,482		25,482	23
	6,415		6,415	24
	7,739		7,739	25
	2,693		2,693	26
	1,026		1,026	27
	5,772		5,772	28
	1,026		1,026	29
	1,984,377		1,984,377	30
	90		90	31
	691		691	32
	19,347		19,347	33
	1,685		1,685	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
	720		720	1
	277		277	2
	47		47	3
	8,031		8,031	4
	90		90	5
	43		43	6
	180		180	7
	626		626	8
	648		648	9
	360		360	10
	12,717		12,717	11
	245		245	12
	1,440		1,440	13
	1,947		1,947	14
	61		61	15
	1,080		1,080	16
	241		241	17
	19,046		19,046	18
	27,371		27,371	19
	35,336		35,336	20
	94,653		94,653	21
	126,998		126,998	22
	33,363		33,363	23
	103,302		103,302	24
	12,952		12,952	25
	144		144	26
	105,610		105,610	27
	22,232		22,232	28
	3,240		3,240	29
	554		554	30
	10,355		10,355	31
	674		674	32
	500		500	33
	345		345	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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.
	1,444		1,444	1
	4,621		4,621	2
	4,679		4,679	3
	961		961	4
	68		68	5
	3,444		3,444	6
	122		122	7
	366		366	8
	1,464		1,464	9
	122		122	10
	32,139		32,139	11
	5,200		5,200	12
	2,381		2,381	13
	2,503		2,503	14
	137		137	15
	1,942		1,942	16
	244		244	17
	234		234	18
	3,188		3,188	19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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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 Raft River expired September 30, 2011. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

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.: 5 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

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

The contract between Idaho Power and the Milner Irrigation District expires December 31, 2012.

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

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

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2016. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Legacy, contract prior to the Open Access Transmission Tariff

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

The agreement between Idaho Power and the United States Department of the Interior, Bureau of Indian Affairs is subject to termination upon 90 days written notice by the Bureau.

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

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328.6 Line No.: 5 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	04/13/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	21,503	21,503		138,336		138,336
2	Avista Corp-WWP Div	SFP	274,437	274,437		1,473,302		1,473,302
3	Avista Corp-WWP Div	OS					-36,582	-36,582
4	Bonneville Power Admin	OS					447	447
5	Bonneville Power Admin	NF	1,700	1,700		8,011		8,011
6	Bonneville Power Admin	LFP	286,453	286,453	1,195,392			1,195,392
7	Bonneville Power Admin	LFP			30,404			30,404
8	Bonneville Power Admin	SFP				330		330
9	Cargill Power Markets	SFP	4	4		144		144
10	Northwestern Energy	LFP	20,710	20,710	199,600			199,600
11	NorthWesern Energy	SFP	45,995	45,995		818,047		818,047
12	NorthWestern Energy	OS					-205,566	-205,566
13	PacifiCorp Inc.	LFP	8,720	8,720		759,375		759,375
14	PacifiCorp Inc.	NF	34,690	34,690		194,002		194,002
15	PacifiCorp Inc.	OS					-21,949	-21,949
16	PacifiCorp Inc.	SFP	46,666	46,666		649,815		649,815
	TOTAL		1,287,651	1,287,651	1,425,396	5,499,661	-462,953	6,462,104

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	OS					-75,143	-75,143
2	Portland General Ele Co	SFP	361,028	361,028		911,685		911,685
3	Powerex Corp.	OS					-124,160	-124,160
4	Puget Sound Energy, Inc	SFP	600	600		750		750
5	Seattle City Light	SFP	182,876	182,876		527,869		527,869
6	Sierra Pacific Power Co	NF	2,269	2,269		17,995		17,995
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,287,651	1,287,651	1,425,396	5,499,661	-462,953	6,462,104

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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	04/13/2012	2011/Q4

FOOTNOTE DATA

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

Resale Transmission

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

Reserves Provided

Schedule Page: 332 Line No.: 6 Column: b

Contract Expiration Date 09/30/2016

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

Contract Expiration Date 07/16/2011

Schedule Page: 332 Line No.: 10 Column: b

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

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

Resale Transmission

Schedule Page: 332 Line No.: 13 Column: b

Contract Expiration Date 05/31/2014

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

Unreserved Usage Distribution

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

Resale Transmission

Schedule Page: 332.1 Line No.: 2 Column: a

Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	405,549
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	268,796
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,071,130
6	Richard Dahl	81,340
7	Christine King	69,097
8	Gary Michael	129,360
9	Richard Reiten	58,974
10	Joan Smith	75,162
11	Jan Packwood	54,390
12	Judith Johansen	70,719
13	Thomas Wilford	66,240
14	Robert Tintsman	71,520
15	Stephen Allred	67,757
16		
17	Chamber of Commerce & Other Civic Organizations	104,397
18		
19	Associated Taxpayers of Idaho	22,000
20	Corporate Executive Board	46,750
21	Idaho Association of Commerce & Industry	14,000
22	Idaho Association of Counties	1,000
23	Idaho Mining Association	6,000
24	Idaho Technology Council	10,000
25	National Association of Directors	4,950
26	Northwest Power Pool	91,722
27	Pacific Northwest Utilities	2,000
28	Western Electricity Coordinating Council	828,246
29	Western Energy Institute	26,095
30	Wyoming Taxpayers Association	1,590
31	Misc Memberships under $1,000 (3)	900
32		
33	Misc General Management	
34	Moody's Analytics Inc	28,832
35	New York Stock Exchange	52,067
36	Port Of Morrow	5,475
37	Pr Newswire	14,063
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,750,121

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/13/2012	2011/Q4

FOOTNOTE DATA

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Transfer & Fees	$ 57,412
Bank Of New York	Port of Morrow	6,593
Broadbridge Financial Solutions	Proxy & Bulletin	49,858
Deutsche Bank	Broker Fees	34,952
E Source	Mgmt Services	23,340
Stock Based Compensation	Stock Expense	432,000
Thomson Financial	Analyst Service	104,855
Wells Fargo	Transfer & fees	125,464
Rate Related Amortization	Misc Expense	230,655
Business Plus	Misc Expense	6,000
Total		$1,071,130

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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			6,764,513		6,764,513
2	Steam Production Plant	18,914,566				18,914,566
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,504,618				15,504,618
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,926,750				4,926,750
7	Transmission Plant	17,667,549				17,667,549
8	Distribution Plant	43,735,020				43,735,020
9	Regional Transmission and Market Operation					
10	General Plant	12,549,538				12,549,538
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	113,001,742		6,764,513		119,766,255

B. Basis for Amortization Charges

Account 404 - Basis used to compute charges:

	Balance to be Amortized 1/1/2011	2011 Amortization	Balance to be Amortized 12/31/2011	Remaining months of Amort 12/31/11
(1)	24,000	12,000	12,000	12
(2)	12,521,781	545,446	11,976,335	-
(3)	17,132,308	5,911,223	18,068,415	-
(4)	4,899,594	287,899	4,611,695	204
(5)	227,990	7,945	225,899	336
Total	34,805,673	6,764,513	34,894,344	

(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) Computer Software packages (Amortized over a 60 month period from date of purchase).
(4) Shoshone-Bannock Right of Way (Termination date December 31, 2028).
(5) Boardman Retrofit Tech Analysis (Termination date December 31,2040)

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	633	75.00		4.16	R4.0	21.80
13	311.00	143,759	100.00	-10.00	1.54	S1.0	23.30
14	312.10	81,207	60.00	-7.00	1.68	R3.0	22.60
15	312.20	484,069	70.00	-5.00	2.17	R1.5	22.30
16	312.30	4,208	25.00	20.00	2.57	R3.0	12.20
17	314.00	150,651	50.00	-5.00	2.50	S0.5	20.30
18	315.00	60,126	65.00	-7.00	6.24	S1.5	22.20
19	316.00	13,265	50.00	-5.00	5.93	R0.5	20.80
20	316.10	92	10.00	25.00	8.13	L2.5	7.60
21	316.40	241	10.00	25.00	9.52	L2.5	
22	316.50	83	10.00	25.00	5.94	L2.5	8.20
23	316.60	106	19.00	25.00	3.69	S2.0	12.00
24	316.70	80	19.00	25.00	3.88	S2.0	16.70
25	316.80	1,300	16.00	30.00	14.29	S0.0	9.30
26	316.90	14	30.00	25.00	1.99	S1.5	21.10
27	317.00	8,005					
28	Subtotal Steam	947,839					
29	331.00	156,227	100.00	-25.00	2.71	R2.5	32.10
30	332.10	19,461	90.00	-20.00	2.27	S4.0	27.20
31	332.20	227,957	90.00	-20.00	2.22	S4.0	29.80
32	332.30	5,472			2.87	SQUARE	28.60
33	333.00	197,921	80.00	-5.00	1.91	R3.0	33.00
34	334.00	45,854	50.00	-5.00	3.00	R1.5	25.30
35	335.00	18,534	90.00		2.11	R2.0	30.50
36	335.10	60	15.00		1.70	SQUARE	12.30
37	335.20	364	20.00		3.53	SQUARE	10.70
38	335.30	124	5.00		13.89	SQUARE	2.00
39	336.00	8,112	75.00		1.94	R3.0	30.40
40	Subtotal Hydro	680,086					
41	341.00	7,169	35.00		3.02	SQUARE	30.40
42	342.00	4,446	35.00		2.75	SQUARE	32.40
43	343.00	98,952	35.00		2.98	SQUARE	29.70
44	344.00	31,682	35.00		2.54	SQUARE	33.80
45	345.00	25,078	35.00		2.89	SQUARE	28.30
46	346.00	3,138	35.00		2.71	SQUARE	29.50
47	Subtotal Other	170,465					
48	350.20	30,980	65.00		1.51	R3.0	54.20
49	352.00	57,995	60.00	-30.00	1.68	R3.0	47.30
50	353.00	351,925	45.00	-5.00	2.06	R1.0	35.40

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	04/13/2012	End of 2011/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	354.00	147,491	65.00	-25.00	1.96	S3.0	48.60
13	355.00	107,027	55.00	-60.00	2.81	R2.0	36.70
14	356.00	171,802	65.00	-30.00	1.92	R1.5	48.30
15	359.00	413	65.00		0.98	R3.0	23.80
16	Subtotal Transmission	867,633					
17	360.22	683	30.00		3.33	SQUARE	30.00
18	361.00	32,336	65.00	-30.00	1.85	R2.5	52.60
19	362.00	194,190	50.00	-5.00	1.89	R0.5	42.10
20	364.00	228,880	44.00	-50.00	3.29	R1.5	31.50
21	365.00	122,537	47.00	-40.00	2.95	R0.5	35.10
22	366.00	47,989	60.00	-20.00	1.95	R2.0	51.20
23	367.00	196,701	50.00	-15.00	1.97	S0.5	41.10
24	368.00	429,420	37.00	5.00	1.67	R1.0	30.80
25	369.00	57,225	35.00	-40.00	3.09	R2.5	25.60
26	370.00	13,834	20.00		6.95	O1.0	11.90
27	370.10	57,488	15.00		6.76	S3.0	14.40
28	370.30	41,109	3.00		25.67	SQUARE	1.50
29	371.10	27	10.00	-5.00	3.68	S4.0	1.40
30	371.20	2,728	15.00	-5.00	0.63	R2.0	13.90
31	373.20	4,395	25.00	-25.00	4.09	R1.5	13.90
32	374.00	643					
33	Subtotal Distribution	1,430,185					
34	390.11	26,794	100.00	-5.00	2.38	S1.5	33.60
35	390.12	57,632	50.00	-5.00	2.24	L2.0	36.30
36	390.20	559	30.00		2.58	S3.0	20.80
37	391.11	14,611	20.00		4.97	SQUARE	10.30
38	391.20	20,992	5.00		24.37	SQUARE	2.10
39	391.21	4,956	7.00		13.96	L4.0	3.90
40	392.10	611	10.00	25.00	6.23	L2.5	5.90
41	392.30	2,590	8.00	50.00	8.62	S2.5	4.30
42	392.40	18,957	10.00	25.00	3.58	L2.5	7.30
43	392.50	766	10.00	25.00	1.49	L2.5	8.60
44	392.60	28,766	19.00	25.00	3.69	S2.0	12.00
45	392.70	4,923	19.00	25.00	2.39	S2.0	11.90
46	392.90	4,365	30.00	25.00	1.99	S1.5	21.10
47	393.00	1,600	25.00		5.40	SQUARE	9.70
48	394.00	6,055	20.00		4.84	SQUARE	11.70
49	395.00	11,866	20.00		5.39	SQUARE	10.20
50	396.00	10,696	16.00	30.00	6.95	S0.0	7.00

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	6,052	15.00		6.16	SQUARE	7.70
13	397.20	20,618	15.00		6.99	SQUARE	9.60
14	397.30	3,514	15.00		8.36	SQUARE	6.60
15	397.40	2,530	10.00		8.20	SQUARE	5.60
16	398.00	5,255	15.00		9.57	SQUARE	6.90
17	Subtotal General	254,708					
18	Total Plant	4,350,916					
19							
20							
21							
22							
23							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	3,420,728		3,420,728	
3					
4	Regulatory FERC fees credit		-465,593	-465,593	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		44,334	44,334	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Rate Case - Misc expenses		29,224	29,224	
13					
14	Regulatory Commission Expenses - Oregon				
15	Rate Case - Misc expenses		10,534	10,534	
16					
17	Other - OPUC				
18	AR - 233		51,581	51,581	
19	UM - 1182		16,345	16,345	
20	UM - 1396		20,721	20,721	
21	UM - 1461		16,225	16,225	
22	PURPA		18,671	18,671	
23	General Regulatory		36,618	36,618	
24	Other matters less than $15,000		91,448	91,448	
25					
26					
27					
28					
29					
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32					
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36					
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40					
41					
42					
43					
44					
45					
46	TOTAL	3,579,229	-129,892	3,449,337	

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	3,420,728					2
							3
Electric	928	-465,593					4
							5
							6
Electric	928	44,334					7
							8
Electric	928	158,501					9
							10
							11
Electric	928	29,224					12
							13
							14
Electric	928	10,534					15
							16
							17
Electric	928	51,581					18
Electric	928	16,345					19
Electric	928	20,721					20
Electric	928	16,225					21
Electric	928	18,671					22
Electric	928	36,618					23
Electric	928	91,448					24
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		3,449,337					46

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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	04/13/2012	End of 2011/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	Approximately $4 million of Idaho Power's 2011	
2	energy efficiency spending was related to	
3	research and analysis, education, technology	
4	evaluation and market transformation. Most of	
5	this activity was done in conjuction with the	
6	Northwest Energy Efficiency Alliance (NEEA).	
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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	04/13/2012	End of 2011/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	16,828,328		
4	Transmission	6,540,757		
5	Regional Market			
6	Distribution	16,919,375		
7	Customer Accounts	8,747,995		
8	Customer Service and Informational	4,518,214		
9	Sales			
10	Administrative and General	42,450,346		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	96,005,015		
12	Maintenance			
13	Production	6,667,843		
14	Transmission	3,223,742		
15	Regional Market			
16	Distribution	8,693,630		
17	Administrative and General	1,150,256		
18	TOTAL Maintenance (Total of lines 13 thru 17)	19,735,471		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	23,496,171		
21	Transmission (Enter Total of lines 4 and 14)	9,764,499		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,613,005		
24	Customer Accounts (Transcribe from line 7)	8,747,995		
25	Customer Service and Informational (Transcribe from line 8)	4,518,214		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	43,600,602		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	115,740,486		115,740,486
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	04/13/2012	End of 2011/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)	115,740,486		115,740,486
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	49,828,835		49,828,835
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	49,828,835		49,828,835
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	4,953,227		4,953,227
79	Other Clearing Accounts	3,094,618		3,094,618
80	Other work in progress	2,261,561		2,261,561
81	Paid absences	19,830,321		19,830,321
82	Preliminary survey and investigation	37,691		37,691
83	Other Accounts	4,739,655		4,739,655
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	34,917,073		34,917,073
96	TOTAL SALARIES AND WAGES	200,486,394		200,486,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	4,771	10	800	3,643	250	703		175	
2	February	4,780	1	800	3,609	218	703		250	
3	March	4,516	8	800	3,368	195	703		250	
4	Total for Quarter 1	14,067			10,620	663	2,109		675	
5	April	4,209	26	800	2,649	174	642		744	
6	May	4,155	5	800	2,630	189	567		769	
7	June	5,222	22	1800	3,802	279	567		574	
8	Total for Quarter 2	13,586			9,081	642	1,776		2,087	
9	July	5,492	22	1800	4,364	302	567		259	
10	August	5,462	25	1800	4,305	302	567		288	
11	September	5,037	8	1700	3,707	269	567		494	
12	Total for Quarter 3	15,991			12,376	873	1,701		1,041	
13	October	4,456	1	1800	3,098	206	567		585	
14	November	4,410	16	800	3,368	199	567		276	
15	December	4,544	15	800	3,371	208	567		398	
16	Total for Quarter 4	13,410			9,837	613	1,701		1,259	
17	Total Year to Date/Year	57,054			41,914	2,791	7,287		5,062	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	4,820,344
4	Nuclear	
5	Hydro-Conventional	10,936,822
6	Hydro-Pumped Storage	
7	Other	137,829
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	15,894,995
10	Purchases	2,777,898
11	Power Exchanges:	
12	Received	602,391
13	Delivered	680,849
14	Net Exchanges (Line 12 minus line 13)	-78,458
15	Transmission For Other (Wheeling)	
16	Received	6,094,045
17	Delivered	6,092,216
18	Net Transmission for Other (Line 16 minus line 17)	1,829
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,596,264
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,734,430
23	Requirements Sales for Resale (See instruction 4, page 311.)	38,222
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,596,702
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,226,910
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,596,264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,597,182	299,156	2,231	4	8 AM
30	February	1,335,990	227,298	2,261	2	8 AM
31	March	1,428,726	307,278	1,907	8	8 AM
32	April	1,345,151	329,304	1,761	6	8 AM
33	May	1,492,714	389,411	1,746	16	11 AM
34	June	1,776,088	467,350	2,842	28	7 PM
35	July	1,859,037	162,831	2,973	6	8 PM
36	August	1,812,353	219,992	2,887	25	5 PM
37	September	1,649,332	352,808	2,564	7	6 PM
38	October	1,415,974	371,794	1,974	1	6 PM
39	November	1,365,640	237,956	1,933	16	8 AM
40	December	1,518,077	231,524	2,135	8	8 AM
41	TOTAL	18,596,264	3,596,702			

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

Page 329 column I differs from Page 401 by 1,829 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	04/13/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.20		
6	Net Peak Demand on Plant - MW (60 minutes)	710			60		
7	Plant Hours Connected to Load	8760			6927		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	3865922000			287766000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	66616189			13839832		
15	Equipment Costs	456703918			60888268		
16	Asset Retirement Costs	0			0		
17	Total Cost	523814465			74834710		
18	Cost per KW of Installed Capacity (line 17/5) Including	679.8371			1165.6497		
19	Production Expenses: Oper, Supv, & Engr	180745			903348		
20	Fuel	92177415			5683939		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4331677			83277		
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	7067950			594345		
27	Rents	498085			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	46835			2028723		
30	Maintenance of Structures	2251			43886		
31	Maintenance of Boiler (or reactor) Plant	6570615			1064		
32	Maintenance of Electric Plant	3076437			235224		
33	Maintenance of Misc Steam (or Nuclear) Plant	5702564			421392		
34	Total Production Expenses	119654574			9995198		
35	Expenses per Net KWh	0.0310			0.0347		
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	2161284	10732	0	171802	1170	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9216	140000	0	8341	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.722	150.926	0.000	28.907	132.823	0.000
41	Average Cost of Fuel per Unit Burned	42.137	82.085	0.000	32.042	121.791	0.000
42	Average Cost of Fuel Burned per Million BTU	2.282	13.954	0.000	1.937	20.889	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	10337.000	0.000	0.000	9897.000	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	04/13/2012	End of 2011/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2001			2005			4
283.50			270.90			172.80			5
262			249			194			6
8718			720			329			7
0			261426			164159			8
0			0			0			9
0			0			0			10
0			6			7			11
666656000			89344000			48459000			12
1106140			402745			0			13
63302625			5699334			1458303			14
277849448			104008915			58385597			15
0			0			0			16
342258213			110110994			59843900			17
1207.2600			406.4636			346.3189			18
606068			228712			159970			19
21983600			7535390			4154978			20
0			0			0			21
2535456			0			0			22
0			0			0			23
0			0			0			24
2231309			262895			250526			25
2071969			158311			87970			26
0			0			0			27
0			0			0			28
0			0			0			29
874472			89921			82402			30
8779359			22042			37902			31
3515974			575143			986528			32
362107			0			0			33
42960314			8872414			5760276			34
0.0644			0.0993			0.1189			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
336503	10231	0	958759	0	0	504442	0	0	38
9959	138778	0	1027	0	0	1027	0	0	39
55.215	142.477	0.000	7.860	0.000	0.000	8.237	0.000	0.000	40
61.006	136.892	0.000	7.860	0.000	0.000	8.237	0.000	0.000	41
3.063	23.486	0.000	7.653	0.000	0.000	8.020	0.000	0.000	42
0.033	0.000	0.000	0.084	0.000	0.000	0.086	0.000	0.000	43
10144.000	0.000	0.000	11021.000	0.000	0.000	10691.000	0.000	0.000	44

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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) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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

This footnote applies to lines 3 and 4. The Jim Bridger Power Plant consists of four equal units constructed jointly by Idaho Power Company and Pacific Power and Light Company, with Idaho owning 1/3 and PacifiCorp owning 2/3. Unit #1 was placed in commercial operation November 30, 1974, Unit #2 December 1, 1975, Unit #3 September 1, 1976, and Unit #4 November 29, 1979.

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

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

Schedule Page: 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	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949
4	Year Last Unit was Installed	1978	1950
5	Total installed cap (Gen name plate Rating in MW)	92.30	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	108	77
7	Plant Hours Connect to Load	8,694	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	586,802,000	513,605,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,358
15	Structures and Improvements	11,807,207	1,039,561
16	Reservoirs, Dams, and Waterways	4,293,075	8,413,888
17	Equipment Costs	31,659,620	8,393,112
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,474,496	19,101,396
21	Cost per KW of Installed Capacity (line 20 / 5)	536.0184	254.6853
22	Production Expenses		
23	Operation Supervision and Engineering	222,397	782,452
24	Water for Power	1,674,772	699,745
25	Hydraulic Expenses	116,486	780,235
26	Electric Expenses	50,572	45,043
27	Misc Hydraulic Power Generation Expenses	210,138	244,914
28	Rents	-568	-45,035
29	Maintenance Supervision and Engineering	89,270	151,939
30	Maintenance of Structures	211,483	274,177
31	Maintenance of Reservoirs, Dams, and Waterways	7,497	518,836
32	Maintenance of Electric Plant	292,363	86,802
33	Maintenance of Misc Hydraulic Plant	103,363	154,730
34	Total Production Expenses (total 23 thru 33)	2,977,773	3,693,838
35	Expenses per net KWh	0.0051	0.0072

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
680	14	220	6
8,760	8,711	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	6	11
2,924,285,000	50,909,000	1,397,275,000	12
			13
17,382,696	82,142	1,210,187	14
31,438,553	7,364,154	9,963,201	15
67,073,285	3,145,630	30,466,784	16
55,992,367	12,696,273	15,820,683	17
518,444	122,668	565,844	18
0	0	0	19
172,405,345	23,410,867	58,026,699	20
294.5086	1,884.9329	305.4037	21
			22
632,600	204,900	350,884	23
576,341	202,919	298,949	24
901,670	320,137	471,375	25
303,160	131,909	186,903	26
408,009	179,822	273,829	27
304,316	-17	49,901	28
455,958	73,556	236,376	29
197,794	63,144	261,452	30
65,107	483	5,321	31
358,259	63,839	162,548	32
682,115	104,754	247,620	33
4,885,329	1,345,446	2,545,158	34
0.0017	0.0264	0.0018	35

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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)	440	24
7	Plant Hours Connect to Load	8,757	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,816,349,000	173,042,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,811,400	2,777,503
16	Reservoirs, Dams, and Waterways	52,700,383	6,265,302
17	Equipment Costs	17,216,890	4,292,367
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	75,425,166	13,845,231
21	Cost per KW of Installed Capacity (line 20 / 5)	192.6569	635.9775
22	Production Expenses		
23	Operation Supervision and Engineering	377,827	214,911
24	Water for Power	327,519	702,291
25	Hydraulic Expenses	525,528	259,355
26	Electric Expenses	212,729	47,858
27	Misc Hydraulic Power Generation Expenses	249,786	115,885
28	Rents	82,999	0
29	Maintenance Supervision and Engineering	269,283	34,863
30	Maintenance of Structures	72,377	12,790
31	Maintenance of Reservoirs, Dams, and Waterways	211,408	8,405
32	Maintenance of Electric Plant	174,027	30,574
33	Maintenance of Misc Hydraulic Plant	374,531	52,676
34	Total Production Expenses (total 23 thru 33)	2,878,014	1,479,608
35	Expenses per net KWh	0.0010	0.0086

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
92	25	51	6
8,760	8,760	8,627	7
			8
91	24	53	9
84	14	50	10
6	4	4	11
657,632,000	157,917,000	394,475,000	12
			13
5,473,876	51,675	255,499	14
9,203,458	25,453,938	10,808,047	15
10,438,597	13,856,887	7,908,870	16
11,937,740	30,331,287	20,759,503	17
248,183	835,946	1,917,603	18
0	0	0	19
37,301,854	70,529,733	41,649,522	20
450.5055	2,821.1893	789.7141	21
			22
870,472	212,122	232,982	23
843,278	174,581	216,977	24
1,171,858	148,772	178,393	25
42,777	34,517	53,462	26
355,585	113,831	148,674	27
-113,298	-31,048	-11,887	28
96,665	61,292	30,047	29
128,592	79,419	38,832	30
115,796	183,048	37,877	31
134,533	22,414	38,864	32
144,740	125,136	79,005	33
3,790,998	1,124,084	1,043,226	34
0.0058	0.0071	0.0026	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	04/13/2012	End of 2011/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)	37	14
7	Plant Hours Connect to Load	8,760	8,640
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	2
12	Net Generation, Exclusive of Plant Use - Kwh	293,884,000	110,438,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,013,430	1,231,506
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	7,763,706	4,523,995
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,578,065	6,632,614
21	Cost per KW of Installed Capacity (line 20 / 5)	451.5381	530.6091
22	Production Expenses		
23	Operation Supervision and Engineering	388,900	193,209
24	Water for Power	373,144	169,172
25	Hydraulic Expenses	551,980	127,220
26	Electric Expenses	86,416	38,400
27	Misc Hydraulic Power Generation Expenses	205,221	107,273
28	Rents	0	-315
29	Maintenance Supervision and Engineering	97,699	21,664
30	Maintenance of Structures	115,610	31,721
31	Maintenance of Reservoirs, Dams, and Waterways	254,149	6,789
32	Maintenance of Electric Plant	67,839	46,273
33	Maintenance of Misc Hydraulic Plant	239,825	67,634
34	Total Production Expenses (total 23 thru 33)	2,380,783	809,040
35	Expenses per net KWh	0.0081	0.0073

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	65	59	6
0	8,760	8,653	7
			8
0	64	61	9
0	60	1	10
0	7	2	11
0	391,028,000	435,475,000	12
			13
114,367	424,428	138,100	14
26,615,283	2,805,900	10,340,105	15
13,556,785	6,916,532	17,114,934	16
1,288,563	8,069,424	27,665,197	17
99,051	88,693	501,877	18
0	0	0	19
41,674,049	18,304,977	55,760,213	20
0.0000	305.0830	937.9346	21
			22
0	379,189	233,958	23
0	352,498	2,115,819	24
6,376,408	379,465	119,064	25
0	232,553	49,500	26
0	203,217	236,962	27
0	-13,894	-11,941	28
0	73,977	44,160	29
0	156,154	43,701	30
0	8,085	80,612	31
0	119,879	79,594	32
54,282	160,281	74,106	33
6,430,690	2,051,404	3,065,535	34
0.0000	0.0052	0.0070	35

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FOOTNOTE DATA

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

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

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

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

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

Upstream storage in Brownlee Reservoir

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	16,495	1,759,923
3	Thousand Springs	1912	8.80	7.4	17,211	9,322,833
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	4.2	26	909,259
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9						
10						
11	(1) Salmon units are classified as standby.					
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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	04/13/2012	End of 2011/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	123,037		36,555			2
1,059,413	213,644		252,473			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
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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) 04/13/2012	Year/Period of Report End of 2011/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	226.40		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	79.29		1
10	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
11	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
12								
13	Quartz	LaGrande	230.00	230.00	H Wood	46.30		1
14	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
15	Brady	Antelope	230.00	230.00	H Wood	56.29		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	7.56		1
25	Boise Bench	Caldwell	230.00	230.00	H Wood	33.68		1
26	Boise Bench	Cloverdale	230.00	230.00	S Tower	16.10		2
27	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
28	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.06		2
29	Caldwell	Ontario	230.00	230.00	H Wood	29.84		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	68.17		1
33	Danskin	Hubbard	230.00	230.00	H Steel	36.28		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	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	256,381	21,789,412	22,045,793					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		835,662	835,662					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,763,326	17,246,635					6
795 ACSR	571,979	11,048,835	11,620,814					7
1272 ACSR	344,220	6,008,061	6,352,281					8
715.5 ACSR	283,143	5,876,940	6,160,083					9
715.5 ACSR	64,851	12,257,047	12,321,898					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	2,841,222	2,903,440					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	2,930,700	3,039,001					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	2,167,266	2,581,059					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	6,980,587	8,728,801					24
715.5 ACSR								25
1272 ACSR	3,062,812	6,869,820	9,932,632					26
795 AAC		80,895	80,895					27
954 ACSR	34,174	16,039,303	16,073,477					28
2X954 ACSR	224,688	6,285,960	6,510,648					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
	31,147,986	426,733,642	457,881,628					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	04/13/2012	End of 2011/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	5.47		1
2	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
3	Langley Gulch Tap			230.00				
4	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
5	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.23		1
6	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
7	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.32		1
8	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
9	Oxbow	Brownlee	230.00	230.00	S Tower	10.80		2
10	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.32		1
11	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
12	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.03		2
13	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
14	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.16		2
15	Brownlee	Boise Bench	230.00	230.00	S Tower	102.08		2
16	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.31		1
17	Palette Jct	Enterprise	230.00	230.00	H Wood	29.12		1
18	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
19	Borah	Brady #2	230.00	230.00	H Wood	3.56		1
20	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
21								
22	Goshen	State Line	161.00	161.00	H Wood	90.48		1
23	Don	Goshen	161.00	161.00	S Tower	2.39		2
24	Don	Goshen	161.00	161.00	H Wood	48.43		2
25								
26	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	10.99		2
27	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
28	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.12		2
29	Nampa	Caldwell	138.00	138.00	S P Wood	10.75		2
30	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.29		1
31	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
32	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
33	Brady	Fremont	138.00	138.00	S Tower	0.98		2
34	Brady	Fremont	138.00	138.00	H Wood	24.32		2
35	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 ACSR		3,528,033	3,528,033					1
1590 ACSR	1,854,996	9,212,985	11,067,981					2
	896,110		896,110					3
715.5 ACSR	336,186	5,172,731	5,508,917					4
715.5 ACSR								5
795 ACSR	53,068	2,229,410	2,282,478					6
795 ACSR								7
VARIOUS	289,934	8,046,450	8,336,384					8
1272 ACSR	14,810	1,182,550	1,197,360					9
715.5 ACSR	227,825	6,380,708	6,608,533					10
VARIOUS								11
1272 ACSR	92,037	2,097,566	2,189,603					12
1272 ACSR	171,081	1,386,300	1,557,381					13
1272 ACSR	44,687	1,252,130	1,296,817					14
954 ACSR	184,817	5,624,726	5,809,543					15
715.5 ACSR	247,857	5,599,323	5,847,180					16
1272 ACSR	84,014	1,739,212	1,823,226					17
1272 ACSR	3,068	416,606	419,674					18
715.5 ACSR								19
1272 ACSR	10,064	311,349	321,413					20
								21
250 COPPER	16,155	648,382	664,537					22
715.5 ACSR	76,041	1,698,355	1,774,396					23
397.5 ACSR								24
								25
250 COPPER	26,507	262,590	289,097					26
250 COPPER								27
715.5 ACSR	21,326	254,909	276,235					28
795 AAC	608,325	1,779,264	2,387,589					29
795 ACSR	47,687	3,565,872	3,613,559					30
795 ACSR	43,568	913,613	957,181					31
795 AAC	270,823	557,504	828,327					32
VARIOUS	564,932	3,770,086	4,335,018					33
VARIOUS								34
VARIOUS								35
	31,147,986	426,733,642	457,881,628					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	04/13/2012	End of 2011/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	King	Lower Malad	138.00	138.00	H Wood	84.51		2
2	Emmett Jct	Payette	138.00	138.00	H Wood	66.46		2
3	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
4	Ontario	Quartz	138.00	138.00	H Wood	73.33		1
5	King	American Falls PP	138.00	138.00	S Tower	1.03		2
6	King	American Falls PP	138.00	138.00	H Wood	141.74		1
7	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
8	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
9	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
10	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
11	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
12	King	Wood River	138.00	138.00	H Wood	73.71		1
13	Boise Bench	Grove	138.00	138.00	S P Wood	10.38		2
14	Quartz	John Day	138.00	138.00	H Wood	67.32		1
15	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
16	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
17	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
18	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
19	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
20	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
21	Wood River	Midpoint	138.00	138.00	H Wood	53.04		2
22	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
23	Oxbow	McCall	138.00	138.00	H Wood	37.16		1
24	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
25	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
26	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
27	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
28	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		2
29	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
30	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.13		2
31	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
32	Blackfoot	Aiken	46.00	138.00	S P Wood	6.18		2
33	Peterson	Tendoy	69.00	138.00	H Wood	57.21		1
34	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
35	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.83		2
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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.
VARIOUS	76,823	2,316,106	2,392,929					1
VARIOUS	30,918	2,512,162	2,543,080					2
397.5 ACSR	1,955	12,983	14,938					3
VARIOUS	34,428	2,150,955	2,185,383					4
715.5 ACSR	216,919	7,976,117	8,193,036					5
715.5 ACSR								6
715.5 ACSR								7
4\0	4,191	309,857	314,048					8
954 ACSR		96,921	96,921					9
250 COPPER	2,741	93,073	95,814					10
VARIOUS	28,490	2,150,317	2,178,807					11
VARIOUS	173,683	2,834,498	3,008,181					12
VARIOUS	225,602	1,652,772	1,878,374					13
397.5 ACSR	92,173	2,362,416	2,454,589					14
VARIOUS	20	77,199	77,219					15
715.5 ACSR	3,168,369	9,724,534	12,892,903					16
VARIOUS								17
795AAC								18
1272 ACSR								19
250 COPPER	450	199,195	199,645					20
397.5 ACSR	349,712	6,997,913	7,347,625					21
397.5 ACSR								22
397.5 ACSR	109,899	2,306,969	2,416,868					23
397.5 ACSR								24
715.5 ACSR	211,131	1,448,294	1,659,425					25
715.5 ACSR	3,324	1,190,604	1,193,928					26
397.5 ACSR	14,927	587,404	602,331					27
715.5 ACSR	13,734	1,051,324	1,065,058					28
397.5 ACSR	18,223	1,276,855	1,295,078					29
VARIOUS	54,848	2,969,759	3,024,607					30
715.5 ACSR	16,790	206,158	222,948					31
715.5 ACSR	13,616	491,359	504,975					32
397.5 ACSR	395,696	3,449,949	3,845,645					33
715.5 ACSR	343,955	2,136,683	2,480,638					34
795 ACSR								35
	31,147,986	426,733,642	457,881,628					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Boise Bench	Mora	138.00	138.00	H Wood	13.18		2
2	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
3	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
4	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	10.06	2.98	1
5	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
6	Eagle	Star	138.00	138.00	S P Wood	6.39		1
7	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.08		1
8	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.40	4.02	1
9	Victory Jct	Victory	138.00	138.00	S P Steel	1.90		1
10	Butler	Wye	138.00	138.00	S P Steel	2.94		1
11	Horseflat	Starkey	138.00	138.00	H Wood	33.86		1
12	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
13	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
14	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
15	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
16	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.80		1
17	Garnet	Ward		138.00				
18	McCall	Lake Fork	138.00	138.00	S P Wood	8.80		1
19	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
20	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
21	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
22	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
23	Valivue Tap		138.00	138.00	S P Steel	0.80		2
24	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
25	Donn	HOKU	138.00	138.00	S P Steel	2.74		1
26	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.31		1
27	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
28	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
29	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
30	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
31	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
32	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
33	C J Strike	Strike Jct	138.00	138.00	S Tower	4.32		2
34	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.39		1
35	Strike Jct	Bowmont		138.00	H Wood	0.05		1
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	14,697	637,273	651,970					1
795 AAC		49,642	49,642					2
795 AAC	489,037	1,944,888	2,433,925					3
1272 ACSR	935,725	3,601,861	4,537,586					4
1272 ACSR	34,687	838,605	873,292					5
715.5 ACSR	179,817	2,909,434	3,089,251					6
795 AAC	43,035	435,188	478,223					7
1272 ACSR	140,412	709,148	849,560					8
1272 ACSR								9
795 ACSR	134,471	1,405,436	1,539,907					10
715.5 ACSR	2,473,833	18,432,096	20,905,929					11
715.5 ACSR								12
715.5 ACSR								13
715.5 ACSR								14
715.5 ACSR								15
1272 ACSR	78,579	1,821,921	1,900,500					16
	40,580		40,580					17
715.5 ACSR	331,539	4,682,879	5,014,418					18
								19
1272 ACSR	272,231	2,141,218	2,413,449					20
795 ACSR								21
795 ACSR								22
795 ACSR		351,497	351,497					23
715.5 ACSR	1,174	212,777	213,951					24
1272 ACSR	190	398	588					25
795 ACSR		356,945	356,945					26
1272 ACSR								27
795 ACSR								28
795 ACSR								29
250 COPPER	58	63,805	63,863					30
715.5 ACSR		76,560	76,560					31
397.5 ACSR		4,406	4,406					32
715.5 ACSR	5,566	384,068	389,634					33
397.5 ACSR	4,355	2,220,763	2,225,118					34
715.5 ACSR	86,651	1,866,338	1,952,989					35
	31,147,986	426,733,642	457,881,628					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
2	Strike Jct	Bowmont	138.00	138.00	H Wood	68.24		1
3	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
4	Bliss	King	138.00	138.00	H Wood	10.47		1
5	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
6	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
7								
8								
9								
10	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
11								
12								
13	69 Kv Lines		69.00	69.00	H Wood	166.31		1
14	69 Kv Lines		69.00	69.00	S P Wood	938.98		1
15								
16								
17	46 Kv Lines		46.00	46.00	S P Wood	409.08		1
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
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31								
32								
33								
34								
35								
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
								2
715.5 ACSR	7	279,481	279,488					3
715.5 ACSR	5,620	1,052,343	1,057,963					4
715.5 ACSR	2,814	183,606	186,420					5
397.5 ACSR	12,885	261,511	274,396					6
								7
								8
								9
397.5 ACSR	1,978	63,404	65,382					10
								11
								12
VARIOUS	1,499,275	49,640,986	51,140,261					13
VARIOUS								14
								15
								16
VARIOUS	307,949	13,432,476	13,740,425					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	31,147,986	426,733,642	457,881,628					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	04/13/2012	End of 2011/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	Rockland Jct	Tockland Wind Farm	5.31	S Pole	19.50	1	1
2	Kimberly Tap		1.83	S Pole	9.40	2	2
3	Victory Jct	Victory	1.90	S Pole	19.50	1	1
4							
5	Neils Hot Springs	Neils Hot Springs	10.44	W Pole	9.90	1	1
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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21							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		19.48		58.30	5	5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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)	
795	ACSR	TAS	138		240,720	116,225		356,945	1
795	ACSR	TVS-DC-HL	138		642,849	434,937		1,077,786	2
1272	ACSR	TAS	138	52,884	1,072,208	715,589		1,840,681	3
									4
397.5	ACSR	T	69		1,223	1,841		3,064	5
									6
									7
									8
									9
									10
									11
									12
									13
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									40
									41
									42
									43
				52,884	1,957,000	1,268,592		3,278,476	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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) 04/13/2012	Year/Period of Report End of 2011/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	distribution	138.00	13.09	
2	Caldwell	transmission	138.00	69.00	12.47
3	Caldwell	transmission	230.00	138.00	12.47
4	Caldwell	distribution	13.00	4.16	
5	Canyon Creek	distribution	138.00	35.00	
6	Canyon Creek	transmission	138.00	69.00	12.98
7	Cascade Power Plant - attended	transmission	69.00	4.60	
8	Cascade	Distribution	69.00	13.10	
9	Chestnut	distribution	138.00	13.00	
10	Clear Lake - attended	transmission	46.00	2.40	
11	Cliff	transmission	138.00	46.00	12.50
12	Cliff	transmission	138.00	46.00	12.95
13	Cloverdale	Distribution	138.00	13.00	
14	Dale	distribution	46.00	13.00	
15	Dale	distribution	69.00	13.00	
16	Dale	distribution	138.00	36.20	
17	Dale	Transmission	138.00	46.00	12.47
18	Danskin- attended	Transmission	230.00	18.00	
19	Danskin- attended	transmission	230.00	138.00	13.80
20	Danskin- attended	distribution	18.00	4.16	
21	Danskin- attended	transmission	138.00	12.00	
22	Don	distribution	138.00	7.60	
23	Don	distribution	138.00	13.20	
24	Don	distribution	138.00	13.00	
25	Don	distribution	14.00		
26	DRAM	distribution	138.00	13.09	
27	DRAM	transmission	230.00	138.00	13.80
28	DRAM	distribution	138.00	12.47	
29	Duffin	distribution	138.00	35.00	
30	Eagle	distribution	138.00	13.09	
31	Eastgate	distribution	138.00		
32	Eastgate	distribution	138.00	13.00	
33	Eckert	distribution	138.00	36.20	
34	Eden	distribution	138.00	36.20	
35	Eden	transmission	138.00	46.00	12.98
36	Elkhorn	distribution	138.00	12.47	
37	Elkhorn	distribution	138.00	13.00	
38	Elmore	distribution	138.00	35.00	
39	Elmore	transmission	138.00	69.00	12.50
40	Emmett	distribution	138.00		

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	04/13/2012	End of 2011/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	1					1
75	3					2
240	2					3
		1				4
15	1					5
15	1					6
12	1					7
10	1					8
48	2					9
4	1					10
12	2	1				11
4	1					12
48	2					13
		7				14
		1				15
27	1					16
25	1					17
140	1					18
180	1					19
6	1					20
96	2					21
		1				22
108	6	3				23
26	1	1				24
80	6					25
118	7					26
160	2					27
17	1					28
36	2					29
38	2					30
24	1					31
18	1					32
18	1					33
24	1					34
15	1					35
8	1					36
8	1					37
17	1					38
30	2					39
24	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Emmett	Transmission	138.00	69.00	12.47
2	Falls	distribution	46.00	13.00	
3	Filer	distribution	46.00	13.00	
4	Flying H	distribution	69.00	2.40	
5	Fort Hall	distribution	46.00	13.00	
6	Fossil Gulch	distribution	138.00	35.00	
7	Fremont	transmission	138.00	46.00	12.50
8	Gary	distribution	138.00	13.00	
9	Gem	distribution	69.00	13.00	
10	Gem	distribution	69.00		
11	Goodng Rural	distribution	46.00	13.00	
12	Golden Valley	distribution	69.00	13.00	
13	Gowen Substation	distribution	138.00	35.00	
14	Grindstone	distribution	35.00		
15	Grove	distribution	138.00	13.09	
16	Hagerman	distribution	46.00	13.00	
17	Hagerman	distribution	46.00	13.00	32.00
18	Hailey	distribution	138.00	13.00	
19	Happy Valley	distribution	138.00	13.09	
20	Haven	distribution	138.00	35.00	
21	Haven	transmission	138.00	46.00	
22	Hemingway	transmission	500.00	230.00	34.50
23	Hewlett Packard	distribution	138.00	13.00	
24	Hidden Springs	distribution	138.00	13.00	
25	Highland	distribution	138.00	13.00	
26	Hill	distribution	138.00	13.00	
27	Hillsdale	distribution	138.00		
28	Hoku	distribution	138.00	13.80	
29	Homedale	distribution	69.00	13.00	
30	Horse Flat	transmission	230.00	138.00	13.80
31	Horseshoe Bend	distribution	35.00		
32	Horseshoe Bend	distribution	69.00	36.20	
33	Horseshoe Bend	distribution	69.00	25.00	
34	Huston	distribution	69.00	13.00	
35	Hulen	distribution	46.00	13.00	
36	Hunt	transmission	230.00	138.00	13.80
37	Hydra	distribution	138.00	36.20	
38	Island	distribution	69.00	13.00	
39	Jerome	distribution	138.00	13.00	
40	Julion Clawson	distribution	138.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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
18	2					2
10	1					3
15	2					4
10	1	1				5
15	1					6
50	3	1				7
37	2					8
8	1					9
10	1					10
15	2					11
10	1	1				12
24	1					13
5	2					14
72	3					15
10	1					16
5	1					17
20	1					18
18	1					19
12	1					20
25	1					21
600	3	1				22
20	1					23
8	1					24
18	1					25
39	2					26
24	1					27
72	2					28
22	2					29
100	1					30
5	1					31
12	1					32
5	1					33
10	1					34
10	1					35
300	3					36
48	2					37
12	1					38
40	2					39
30	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	04/13/2012	End of 2011/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	Joplin	distribution	138.00	13.00	
2	Joplin	distribution	138.00	35.00	
3	Karcher	distribution	138.00	13.00	
4	Kenyon	distribution	69.00	13.00	
5	Ketchum	distribution	138.00	13.00	
6	Kimberly	distribution	138.00	13.00	
7	Kinport	transmission	161.00	46.00	13.20
8	Kinport	transmission	230.00	138.00	12.47
9	Kinport	transmission	230.00	138.00	13.80
10	Kinport	transmission	345.00	230.00	13.80
11	Kramer	distribution	138.00	35.00	
12	Kramer	distribution	138.00	36.20	
13	Kuna	distribution	138.00	13.00	
14	Lake Fork	distribution	138.00	36.20	
15	Lake Fork	transmission	138.00	69.00	12.50
16	Lamb	distribution	138.00	13.00	
17	Lansing	distribution	69.00	13.00	
18	Lincoln	distribution	138.00	13.09	
19	Linden	distribution	138.00	13.00	
20	Locust	distribution	138.00	36.20	
21	Locust	transmission	230.00	138.00	13.80
22	Lower Malad - attended	transmission	138.00	7.20	
23	Lower Salmon - attended	transmission	138.00	13.80	
24	Map Rock	distribution	69.00	13.00	
25	McCall	distribution	13.00	13.09	
26	McCall	distribution	138.00	36.20	
27	Meridian	distribution	138.00	13.00	
28	Micron	distribution	138.00	13.09	
29	Micron	distribution	138.00	13.00	
30	Midpoint	transmission	230.00	138.00	13.80
31	Midpoint	transmission	345.00	230.00	13.80
32	Midpoint	transmission	500.00	345.00	
33	Midrose	distribution	138.00	13.09	
34	Milner	transmission	138.00	69.00	12.47
35	Milner	distribution	69.00	46.00	6.90
36	Milner	distribution	138.00	35.00	
37	Milner PP - attended	transmission	138.00	13.80	
38	Moonstone	distribution	138.00	35.00	
39	Mora	distribution	138.00	35.00	
40	Mora	distribution	138.00	36.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
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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
18	1					2
12	1					3
20	2					4
42	2					5
18	1					6
		7				7
180	1					8
180	1					9
600	3	1				10
12	1					11
18	1					12
15	1					13
18	1					14
15	1					15
18	1					16
12	1					17
10	1					18
33	2					19
48	2					20
360	2					21
16	1					22
70	4					23
10	1					24
12	1					25
18	1					26
36	2					27
24	2					28
24	2					29
120	1					30
720	2					31
750	3	1				32
24	1					33
100	4					34
8	3	1				35
29	2					36
36	1					37
12	1					38
15	1					39
24	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Moreland	distribution	35.00	13.00	
2	Moreland	distribution	46.00	13.00	
3	Moreland	distribution	46.00	35.00	12.47
4	Mountain Home	distribution	69.00	13.00	
5	Mountain Home Air Force Base	distribution	69.00	13.00	
6	Mountain Home Air Force Base	distribution	138.00	13.00	
7	Nampa	distribution	230.00	138.00	13.80
8	Nampa	distribution	138.00	13.00	
9	New Meadows	distribution	138.00	36.20	
10	New Plymouth	distribution	69.00	13.00	
11	Notch Butte	distribution	138.00	13.09	
12	Orchard	distribution	69.00	36.20	
13	Orchard	distribution	69.00	35.00	12.47
14	Parma	distribution	69.00	13.00	
15	Parma	distribution	69.00	35.00	
16	Paul	distribution	138.00	35.00	
17	Payette	distribution	138.00	13.00	
18	Pingree	transmission	138.00	46.00	12.50
19	Pingree	distribution	138.00	35.00	
20	Pleasant Valley	distribution	138.00	35.00	
21	Pocatello	distribution	46.00	13.00	
22	Poleline	distribution	138.00	13.09	
23	Populus	transmission	345.00		
24	Portneuf	distribution	138.00	35.00	
25	Portneuf	distribution	46.00	35.00	
26	Rockford	distribution	46.00	13.00	
27	Russett	distribution	138.00	13.00	
28	Sailor Creek	distribution	138.00	2.40	
29	Sailor Creek	distribution	138.00	35.00	
30	Salmon	distribution	69.00	13.00	
31	Salmon	distribution	69.00	34.50	12.47
32	Salmon	distribution	69.00		12.47
33	Salmon	transmission	13.00	2.40	
34	Shoshone	distribution	46.00	13.00	
35	Shoshone	distribution	46.00	7.20	
36	Shoshone Falls - attended	transmission	46.00	2.30	
37	Shoshone Falls - attended	transmission	46.00	6.60	
38	Silver	distribution	138.00	35.00	
39	Simplot	distribution	138.00	13.00	
40	Sinker Creek	distribution	138.00	35.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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.
6	1					1
8	1					2
8	4					3
15	1					4
		1				5
18	1					6
180	1					7
50	3					8
12	1					9
10	1					10
10	1					11
6	1					12
10	3					13
10	1					14
12	1					15
36	2					16
23	3					17
50	3					18
22	2					19
42	2					20
36	2					21
18	1					22
						23
18	1					24
		1				25
14	2					26
18	1					27
15	2					28
15	1					29
10	1	3				30
10	3					31
		2				32
5	2					33
10	1					34
2	3					35
3	1					36
10	1					37
12	1					38
15	1					39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/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	Siphon	distribution	138.00	35.00	
2	South Park	distribution	46.00	13.00	
3	Star	distribution	138.00	13.09	
4	Starkey	Transmission	138.00	69.00	12.47
5	State	distribution	69.00	13.00	
6	Stoddard	distribution	138.00	13.00	
7	Strike Power Plant - attended	transmission	138.00	13.80	
8	Sugar	distribution	138.00	35.00	
9	Swan Falls - attended	transmission	138.00	6.90	
10	Taber	distribution	46.00	13.00	
11	Ten Mile	distribution	138.00	13.09	
12	Terry	distribution	138.00	13.09	
13	Thousand Springs - attended	transmission	46.00	7.20	
14	Thousand Springs - attended	transmission	7.00	2.40	
15	Toponis	distribution	138.00	33.00	
16	Twin Falls	distribution	138.00	13.09	
17	Twin Falls	transmission	138.00	46.00	12.98
18	Twin Falls PP - attended	transmission	138.00	7.20	
19	Twin Falls PP - attended	transmission	138.00	13.20	
20	Upper Malad - attended	transmission	45.00	7.20	
21	Upper Salmon- attended	transmission	138.00	7.20	
22	Ustick	distribution	138.00	13.00	
23	Vallivue	distribution	138.00	13.09	
24	Victory	distribution	138.00	13.00	
25	Victory	distribution	138.00	13.09	
26	Ware	distribution	69.00	13.00	
27	Weiser	distribution	69.00	13.00	
28	Weiser	transmission	138.00	69.00	12.47
29	Wilder	distribution	69.00	13.00	
30	Willis	distribution	138.00	13.09	
31	Wye	distribution	138.00	13.00	
32	Zilog	distribution	138.00	13.09	
33					
34					
35	The above are all State of Idaho				
36					
37	Montana:				
38	Peterson	transmission	230.00	69.00	13.20
39					
40	Nevada:				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
33	2					1
10	1					2
18	1					3
18	1					4
33	2					5
15	1					6
83	3					7
20	2					8
18	1					9
5	1					10
24	1					11
42	3					12
8	1					13
3	1					14
18	1					15
44	2					16
33	2					17
9	1					18
72	1					19
8	1					20
36	4					21
44	2					22
18	1					23
24	1					24
18	1					25
12	1	1				26
20	2					27
25	1					28
10	1					29
18	1					30
56	3					31
24	1					32
						33
						34
						35
						36
						37
30	3	1				38
						39
						40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/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	Valmy - attended	transmission	345.00	17.40	
2	Valmy - attended	transmission	345.00	22.00	
3	Wells	transmission	138.00	69.00	13.00
4					
5	Oregon:				
6	Boardman - attended	transmission	500.00	24.00	
7	Boardman - attended	transmission	230.00	7.20	
8	Boardman - attended	transmission	24.00	7.20	
9	Cairo	distribution	69.00	13.00	
10	Hells Canyon - attended	transmission	230.00	13.80	
11	Hells Canyon - attended	distribution	69.00	0.50	
12	Hines	transmission	138.00	115.00	12.47
13	Malheur Butte	distribution	69.00	34.50	
14	Nyssa	distribution	69.00	13.00	
15	Ontario	distribution	138.00	13.00	
16	Ontario	transmission	138.00	69.00	12.47
17	Ontario	transmission	230.00	138.00	13.80
18	Ontario	transmission	138.00	69.00	12.98
19	Ontario	transmission	138.00	69.00	13.09
20	Ore-Ida	distribution	69.00	13.00	
21	Oxbow - attended	transmission	138.00	69.00	13.00
22	Oxbow - attended	transmission	230.00	13.80	
23	Oxbow - attended	transmission	230.00	138.00	13.80
24	Quartz	transmission	138.00	69.00	12.50
25	Quartz	transmission	230.00	138.00	12.98
26	Quartz	transmission	138.00	69.00	12.98
27	Vale	distribution	69.00	13.00	
28					
29	Wyoming:				
30	Jim Bridger - attended	transmission	345.00	22.00	
31	Jim Bridger - attended	transmission	345.00	230.00	34.50
32					
33					
34					
35					
36					
37	Transformers-distribution substations under 10,000				
38	KVA 84 unattended.				
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	04/13/2012	End of 2011/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.
315	1					1
300	1	1				2
20	3	1				3
						4
						5
685	3	1				6
55	1					7
55	1					8
12	1					9
500	3					10
1	1					11
40	1					12
8	3	1				13
20	2					14
38	2					15
25	1	1				16
240	2					17
50	2					18
		1				19
15	1					20
10	3	1				21
244	2					22
100	1					23
15	1					24
100	3	1				25
15	1					26
10	1					27
						28
						29
1122	2					30
1084	22					31
						32
						33
						34
						35
						36
						37
342						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	04/13/2012	2011/Q4

FOOTNOTE DATA

Schedule Page: 426.2 Line No.: 22 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.: 23 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.: 1 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.: 2 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.: 6 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.: 7 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.: 8 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.: 30 Column: a

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

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

Jointly owned with PacificCorp. 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	04/13/2012	End of 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Managerial Expense	IDACORP, Inc.	417420	457,141
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

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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	$ 969,760,290	$ 978,237,919
3	Operating Expenses			
4	Operation Expenses (401)	15	600,989,160	591,076,570
5	Maintenance Expenses (402)	15	72,381,449	66,618,522
6	Depreciation Expense (403)		108,248,039	101,868,184
7	Amort. & Depl. of Utility Plant (404-405)		6,087,113	5,959,981
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Regulatory Study Costs (407)			
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits/Credits (407.3 & 407.4)		-	-
13	Taxes Other Than Income Taxes (408.1)	2	26,932,746	21,747,745
14	Income Taxes - Federal (409.1)	2	(54,366,437)	7,279,837
15	- Other (409.1)	2	(731,383)	2,997,295
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	16,500,157	2,215,520
17	Investment Tax Credit Adj. - Net (411.4)	2	(1,083,203)	(1,423,437)
18	(Less) Gains from Disp. of Utility Plant (411.6)			
19	Losses from Disp. of Utility Plant (411.7)			
20	(Less) Gains from Disposition of Allowances (411.8)			
21	Losses from Disposition of Allowances (411.9)			
22				
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		774,957,642	798,340,218
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 194,802,648	$ 179,897,701

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 12,338,706
FUTA	115,222
State Unemployment	669,492
Payroll Deduction & Loading	(13,123,419)
Total Labor Related	0
Property Taxes	22,194,277
Kilowatt-hour Tax	2,324,425
Licenses	4,461
Regulatory Commission Fees	2,089,245
Irrigation PIC	320,338
Total Taxes Other Than Income Taxes	26,932,746
Federal Income Taxes	(54,366,437)
State Income Taxes	(731,383)
Deferred Income Taxes	16,500,157
Investment Tax Credit Adjustment - Net	(1,083,203)
Total Taxes Allocated to Idaho	$ (12,748,120)

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)	$ 303,143	$ 94,776
2	Customer Accounts Receivable (Account 142)	63,612,796	67,534,733
3	Other Accounts Receivable (Account 143)	6,166,234	8,206,727
4	(Disclose any capital stock subscription received)		
5	Total	$ 70,082,172	$ 75,836,237
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,641,302	1,435,434
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 68,440,870	$ 74,400,803
12			
13			
14	Notes Receivable - Account 141: (at 12-31-11)		
15	Directors, officers, and employees - $ -		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-11)		
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	$ 1,641,302	$	$	$ (205,868)	$ 1,435,434
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	$ 1,641,302	$ -	$ -	$ (205,868)	$ 1,435,434
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.

2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.

3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.

4. If any note was received in satisfaction of an open account, state the period covered by such open account.

5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.

6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO	$ 14,384,928	$ 46,929,729	$ 43,979,638	$ 17,335,019	
4						
5						
6						
7						
8						
9						
10	Total Account 145	14,384,928	46,929,729	43,979,638	17,335,019	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc.	$ -	$ 133,657,723	$ 133,657,723	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ -	$ 133,657,723	$ 133,657,723	$ -	
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 Property (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	Cloverdale Substation	$ 2,323	4/26/2011*	$ 12,234	
5					
6					
7	Locust Grove Substation	$ 5,681	4/26/2011*	$ (69,433)	
8	*OPUC Approval IPUC Notification				
9					
10					
11					
12					
13					
14	Total gain	$ 8,004		$ (57,199)	
15					
16					
17	CJ Strike	$ 3,834	**		$ (3,155)
18	**Approval pending				
19					
20					
21					
22	Transmission Line #103	*			(200)
23	* Land purchased in 1942. Could not identify				
24	original cost in asset records				
25					
26					
27					
28					
29					
30					
31	Total loss	$ 3,834			$ (3,355)

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADM ASSOCIATES INC	Energy Efficiency Services	$ 49,126
2	AFFORDABLE ENERGY IMPROVEMENTS	Energy Efficiency Services	10,793
3	AGREE TECHNOLOGIES AND SOLUTIO NS	Energy Efficiency Services	160,158
4	BANDUCCI WOODARD SCHWARTZMAN PA	Legal Services	16,555
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	480,287
6	BERGLES LAW LLC	Legal Services	72,756
7	BRASSEY, WETHRELL, & CRAWFORD	Legal Services	43,080
8	BRENNEMAN, JOHN	Lobby Serices	73,990
9	BRIGHAM YOUNG UNIVERSITY	Environmental Services	27,696
10	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	198,292
11	BURNS & MCDONNELL ENGINEERING	Engineering Services	20,000
12	BYRNE & CLAYTON CONSULTING LLC	Consulting Services	16,722
13	CADMUS GROUP INC, THE	Consulting Services	55,646
14	CAPITOL LAW GROUP PLLC	Legal Services	11,140
15	CORPORATE OFFICE INSTALLATIONS	Office Equipment Services	11,935
16	DAVID EVANS AND ASSOCIATES	Consulting Services	26,851
17	DAVIS WRIGHT TREMAINE LLP	Legal Services	517,250
18	DC ENGINEERING, PC	Engineering Services	16,990
19	DELOITTE & TOUCHE	Accounting Services	401,821
20	DESERT RESEARCH INSTITUTE	Environmental Services	81,063
21	DEWEY & LEBOEUF	Legal Services	89,199
22	DHI INC	Environmental Services	184,005
23	ECOS IQ	Consulting Services	40,174
24	EDISON ELECTRIC INSTITUTE	Energy Efficiency Services	10,000
25	EHM ENGINEERS INC	Engineering Services	11,000
26	ERISA LAW GROUP PA	Legal Services	54,949
27	EVANS KEANE	Legal Services	22,364
28	EVERGREEN CONSULTING GROUP, LLC	Consulting Services	158,087
29	EXPERIS IT SERVICES US, LLC	Computer Support Services	11,540
30	FEHRN, BRIAN	Meterologist Services	39,500
31	FREEMAN, SULLIVAN AND COMPANY	Energy Efficiency Services	14,649
32	FRONTIER HISTORICAL CONSULTANT	Consulting Services	21,705
33	GALE ENERGY CONSULTING LLC	Consulting Services	15,000
34	GANNETT FLEMING INC	Energy Efficiency Services	38,411
35	GARTNER GROUP	Computer Support Services	126,900
36	GIVENS PURSLEY LLP	Legal Services	36,634
37	GLAHE & ASSOCIATES INC	Environmental Services	36,500
38	GLOBAL ENERGY PARTNERS LLC	Environmental Services	48,899
39	GRC CODE FIX	Consulting Services	21,975
40	GREENBERG TRAURIG LLP	Legal Services	89,964
41	HARDESTY, REBECCA	Environmental Services	80,669
42	HERITAGE ENVIRONMENTAL CONSULT	Environmental Services	12,114
43	HYQUAL	Environmental Services	203,578
44	IDE LAW & STRATEGY, PPLC	Legal Services	67,500
45	INTER-FLUVE, INC.	Environmental Services	152,747

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	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	$ 158,933
47	JONES AND SWARTZ PLLC	Legal Services	38,999
48	L CONWAY CONSULTING, INC	Consulting Services	21,871
49	MCDOWELL RACKNER & GIBSON PC	Legal Services	981,780
50	MERRILL COMMUNICATIONS LLC	Consulting Services	26,910
51	MIRANDE, MICHAEL	Legal Services	69,918
52	MURPHY LAW OFFICE PLLC	Legal Services	11,852
53	NIELSEN GROUP INC, THE	Consulting Services	222,821
54	NORTHWEST NATURAL RESOURCE GRO	Environmental Services	16,913
55	PAINE HAMBLEN LLP	Manangement Sevices	244,627
56	PARR BROWN GEE & LOVELESS INC	Legal Services	59,012
57	PERKINS COIE LLP	Legal Services	464,806
58	PHONE PRO	Office Equipment Services	12,395
59	PORTLAND ENERGY CONSERVATION	Environmental Services	118,507
60	REYNOLDSON GROUP PLLC	Legal Services	13,363
61	RIDDELL WILLIAMS P.S.	Legal Services	13,488
62	RIVERSIDE TECHNOLOGY INC	Manangement Sevices	57,074
63	SHARP & SMITH INC.	Engineering Services	145,431
64	SOFTWARE AG INC	Computer Support Services	96,040
65	SPATIAL NETWORK SOLUTIONS	Admin Training Services	29,077
66	STAPLEY ENGINEERING, INC	Engineering Services	23,830
67	STILLWATER SCIENCES	Environmental Services	47,004
68	STOEL RIVES LLP	Legal Services	192,688
69	SULLIVAN & CROMWELL	Manangement Sevices	130,977
70	TEKSYSTEMS	Staffing Services	38,961
71	UNIVERSITY CORPORATION FOR	Environmental Services	91,908
72	UNIVERSITY OF IDAHO	Environmental Services	382,664
73	UNIVERSITY OF TENNESSEE	Environmental Services	17,250
74	URS CORPORATION	Environmental Services	31,672
75	UTAH STATE UNIVERSITY	Environmental Services	69,138
76	VAN NESS FELDMAN	Consulting Services	59,825
77	WEATHER MODIFICATION INC	Cloud Seeding Services	367,160
78	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	38,007
79			
80			
81			
82			
83			
84			
85			
86			
87			
88			
89			
	TOTAL		$ 8,175,117.81

PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	A TREEHOUSE	Computer/Printer Supplies	$ 8,862
2	CRAPO SMITH PLLC	Legal Services	8,830
3	DEAN & CARTER PLLC	Legal Services	5,427
4	DIAMOND PARKING INC	Parking Services	5,100
5	ELAM AND BURKE PA	Legal Services	6,758
6	EPICOR SOFTWARE CORPORATION	Computer Services	9,200
7	FOX LAND SURVEYS, INC.	Environmental Services	6,068
8	GE ENERGY SERVICE	Consulting Services	5,194
9	GJORDING & FOUSER, PLLC	Legal Services	7,140
10	HDR ENGINEERING, INC	Engineering Services	5,793
11	KLINE, BARTON L	Consulting Services	8,573
12	OFFICE ENVIRONMENT COMPAN	Office Equipment Services	5,580
13	PROFESSIONAL TRAINING SYSTEMS	Training Services	8,489
14	RIPLEY, LARRY D	Legal Services	6,750
15	SALLADAY & DAVIS	Legal Services	8,910
16	SALLADAY, G LANCE	Consulting Services	6,332
17	SCOTT A WELLS, PHD, PE	Engineering Services	6,644
18	STEPTOE & JOHNSON LLP	Legal Services	6,820
19	TAARP GROUP LLP, THE	Legal Services	6,014
20	TROUT, JONES GLEDHILL FUHRMAN	Legal Services	9,991
21	UNIVERSITY OF ARIZONA	Environmental Services	9,580
22	WASHINGTON 2 ADVOCATES LLC	Consulting Services	5,163
23			
24			
25			
26			
27			
28			
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45	**TOTAL**		$ 157,218.79

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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)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,295	
3	(302) Franchises and Consents	22,096,463	
4	(303) Miscellaneous Intangible Plant	30,622,473	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	52,724,230	
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	3,914,571	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	875,741,735	
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)	667,634,463	
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)	Balance at End of Year (g)		Line No.
					1
			$ 5,457	(301)	2
			22,172,205	(302)	3
			32,839,705	(303)	4
			55,017,367		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			8,275,911	(317)	15
			908,609,888		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
			679,593,365		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)	$ 166,775,956	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,710,152,154	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	29,203,182	
49	(352) Structures and Improvements	47,523,329	
50	(353) Station Equipment	300,054,738	
51	(354) Towers and Fixtures	123,384,005	
52	(355) Poles and Fixtures	86,608,519	
53	(356) Overhead Conductors and Devices	144,200,672	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	271,410	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	731,245,855	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,552,220	
61	(361) Structures and Improvements	28,289,519	
62	(362) Station Equipment	175,260,257	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	208,275,965	
65	(365) Overhead Conductors and Devices	112,894,031	
66	(366) Underground Conduit	47,510,380	
67	(367) Underground Conductors and Devices	188,247,935	
68	(368) Line Transformers	377,055,642	
69	(369) Services	54,375,115	
70	(370) Meters	92,208,012	
71	(371) Installations on Customer Premises	2,517,879	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,156,853	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,295,343,809	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	10,327,475	
78	(390) Structures and Improvements	71,746,675	
79	(391) Office Furniture and Equipment	36,556,870	
80	(392) Transportation Equipment	56,593,719	
81	(393) Stores Equipment	1,354,873	
82	(394) Tools, Shop, and Garage Equipment	5,168,975	
83	(395) Laboratory Equipment	11,091,499	
84	(396) Power Operated Equipment	9,211,910	
85	(397) Communication Equipment	27,122,872	
86	(398) Miscellaneous Equipment	4,421,669	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	233,596,537	
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)	233,596,537	
91	TOTAL (Accounts 101 and 106)	4,023,062,586	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 4,023,062,586	

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
			$ 165,688,363		45
			1,753,891,616		46
					47
			33,615,717	(350)	48
			55,493,339	(352)	49
			336,717,516	(353)	50
			141,131,353	(354)	51
			102,379,364	(355)	52
			164,369,428	(356)	53
				(357)	54
				(358)	55
			395,522	(359)	56
				(359.1)	57
			834,102,239		58
					59
			5,288,037	(360)	60
			31,149,311	(361)	61
			187,486,045	(362)	62
				(363)	63
			211,409,134	(364)	64
			114,428,352	(365)	65
			47,290,854	(366)	66
			193,507,656	(367)	67
			411,389,958	(368)	68
			54,323,982	(369)	69
			109,827,388	(370)	70
			2,529,769	(371)	71
				(372)	72
			4,181,704	(373)	73
				(374)	74
			1,372,812,191		75
					76
			15,434,298	(389)	77
			81,326,079	(390)	78
			38,812,265	(391)	79
			58,352,942	(392)	80
			1,531,151	(393)	81
			5,794,321	(394)	82
			11,355,461	(395)	83
			10,235,988	(396)	84
			31,305,950	(397)	85
			5,028,782	(398)	86
			259,177,237		87
				(399)	88
				(399.1)	89
			259,177,237		90
			4,275,000,649		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 4,275,000,649		96

ELECTRIC OPERATING REVENUES (Account 400)

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

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	**Sales of Electricity**		
2	(440) Residential Sales	$ 389,903,113	$ 385,897,031
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	308,079,555	325,261,915
5	Large (or Industrial)(See Instr. 4) (2)	128,669,701	126,530,113
6	(444) Public Street and Highway Lighting	3,160,616	3,152,822
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	829,812,986 *	840,841,882
11	(447) Sales for Resale - Opportunity	96,933,214	71,503,889
12	TOTAL Sales of Electricity	926,746,200	912,345,771
13	(449) Provision for Rate Refunds	(37,734,708)	(10,624,673)
14	TOTAL Revenue Net of Provision for Refunds	889,011,492	901,721,098
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,477,021	3,455,502
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,065,731	18,807,627
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	54,206,045	54,253,693
22			
23			
24			
25	TOTAL Other Operating Revenues	80,748,798	76,516,821
26	TOTAL Electric Operating Revenues	$ 969,760,290	$ 978,237,919

(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
4,950,935,597	4,777,821,745	396,435	394,132	2
				3
5,259,299,071	5,248,080,006	77,038	76,563	4
2,858,414,142	2,828,443,711	117	118	5
28,922,261	29,217,485	1,557	1,438	6
				7
				8
				9
13,097,571,071 **	12,883,562,947	475,147	472,251	10
3,467,888,272	1,883,300,132	N/A	N/A	11
16,565,459,343	14,766,863,079	475,147	472,251	12
				13

* Includes $833,075.29 unbilled revenues.

** Includes 41,564,025 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	$ 1,617,279	$ 1,801,415
5	(501) Fuel	114,337,717	139,614,702
6	(502) Steam Expenses	6,631,018	6,972,393
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,128,774	2,033,682
10	(506) Miscellaneous Steam Power Expenses	9,314,506	9,345,596
11	(507) Rents	476,607	218,733
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	134,505,900	159,986,521
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,986,057	2,186,957
16	(511) Maintenance of Structures	880,911	295,097
17	(512) Maintenance of Boiler Plant	14,645,611	15,268,185
18	(513) Maintenance of Electric Plant	6,513,885	3,720,438
19	(514) Miscellaneous Steam Plant	6,206,375	3,579,816
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	30,232,838	25,050,493
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	164,738,738	185,037,013
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,147,250	5,113,329
45	(536) Water for Power	8,393,843	6,984,811
46	(537) Hydraulic Expenses	11,973,603	10,179,310
47	(538) Electric Expenses	1,540,819	1,492,017
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,948,258	2,762,087
49	(540) Rents	200,191	387,675
50	TOTAL Operation (Enter Total of lines 44 thru 49)	30,203,965	26,919,229

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	$ 1,687,621	$ 1,877,060
54	(542) Maintenance of Structures	1,648,569	1,102,320
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,495,873	1,305,050
56	(544) Maintenance of Electric Plant	1,711,088	3,026,857
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,602,021	2,889,665
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,145,172	10,200,952
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	39,349,137	37,120,181
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	784,824	313,261
63	(547) Fuel	11,159,408	12,111,625
64	(548) Generation Expenses	717,006	427,597
65	(549) Miscellaneous Other Power Generation Expenses	745,729	429,404
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,406,968	13,281,887
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	41
70	(552) Maintenance of Structures	171,779	173,642
71	(553) Maintenance of Generating and Electric Plant	110,002	112,955
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,781,101	1,027,549
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,062,882	1,314,187
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	15,469,850	14,596,074
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	149,672,898	131,000,128
77	(556) System Control and Load Dispatching	1,166	153
78	(557) Other Expenses	37,451,652	51,884,430
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	187,125,716	182,884,710
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	406,683,441	419,637,978
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,183,091	2,559,146
84	(561) Load Dispatching	2,781,432	2,816,811
85	(562) Station Expenses	2,155,024	1,706,312
86	(563) Overhead Line Expenses	713,799	562,633
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	6,165,151	5,623,961
89	(566) Miscellaneous Transmission Expenses	294,591	288,013
90	(567) Rents	3,141,690	1,341,727
91	TOTAL Operation (Enter Total of lines 83 thru 90)	18,434,779	14,898,602
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	211,076	462,021
94	(569) Maintenance of Structures	409,517	357,888
95	(570) Maintenance of Station Equipment	2,846,961	2,960,318
96	(571) Maintenance of Overhead Lines	3,516,386	2,370,823
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	5,237	(34)
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	6,989,178	6,151,015
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	25,423,957	21,049,617
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,585,869	3,494,071

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	$ 3,335,858	$ 3,280,881
106	(582) Station Expenses	1,151,687	1,226,496
107	(583) Overhead Line Expenses	2,817,997	2,818,499
108	(584) Underground Line Expenses	1,796,817	1,762,795
109	(585) Street Lighting and Signal System Expenses	116,145	75,649
110	(586) Meter Expenses	4,035,316	4,065,420
111	(587) Customer Installations Expenses	1,002,934	1,392,551
112	(588) Miscellaneous Distribution Expenses	5,259,071	4,708,623
113	(589) Rents	795,328	414,753
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,897,022	23,239,738
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	385,136	350,009
117	(591) Maintenance of Structures	5,501	(10,923)
118	(592) Maintenance of Station Equipment	3,119,318	3,623,115
119	(593) Maintenance of Overhead Lines	13,440,348	13,302,525
120	(594) Maintenance of Underground Lines	1,037,269	986,863
121	(595) Maintenance of Line Transformers	415,626	407,395
122	(596) Maintenance of Street Lighting and Signal Systems	527,171	559,210
123	(597) Maintenance of Meters	461,660	674,552
124	(598) Maintenance of Miscellaneous Distribution Plant	231,921	125,929
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	19,623,950	20,018,674
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	43,520,972	43,258,412
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	411,109	392,236
130	(902) Meter Reading Expenses	2,348,997	3,753,549
131	(903) Customer Records and Collection Expenses	12,464,339	12,502,606
132	(904) Uncollectible Accounts	4,016,095	4,479,964
133	(905) Miscellaneous Customer Accounts Expenses	241	327
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	19,240,782	21,128,682
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	494,702	339,665
138	(908) Customer Assistance Expenses	41,237,964	50,028,521
139	(909) Informational and Instructional Expenses	79,709	30,338
140	(910) Miscellaneous Customer Service and Informational Expenses	498,074	831,888
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	42,310,450	51,230,413
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	64,079,786	60,008,898
152	(921) Office Supplies and Expenses	15,024,667	12,833,065
153	(Less) (922) Administrative Expenses Transferred-Credit	(24,823,165)	(26,204,991)

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	$ 4,701,113	$ 6,797,014
156	(924) Property Insurance	3,071,478	3,112,351
157	(925) Injuries and Damages	5,541,210	5,343,230
158	(926) Employee Pensions and Benefits	57,109,122	28,308,455
159	(927) Franchise Requirements	0	2,549
160	(928) Regulatory Commission Expenses	3,046,603	3,293,914
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	526,939	393,976
163	(930.2) Miscellaneous General Expenses	3,579,030	3,606,629
164	(931) Rents	6,796	11,698
165	TOTAL Operation (Enter Total of lines 151 thru 164)	131,863,580	97,506,787
166	Maintenance		
167	(935) Maintenance of General Plant	4,327,428	3,883,202
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	136,191,008	101,389,989
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 673,370,609	$ 657,695,092

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, 2011	December 31, 2010
2	Total Regular Full-Time Employees	1,929	1,928
3	Total Part-Time and Temporary Employees	65	50
4	Total Employees	1,994	1,978