e-FILING REPORT COVER SHEET

REPORT NAME: 2012 FERC Form 1 Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

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

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

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

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

If Yes, enter docket number:

Key words:

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

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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

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

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 16, 2013

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

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

Dear Sir or Madam:

Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report for the year ending December 31, 2012.

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

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosure

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

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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Idaho Power Company	**End of** 2012/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2012/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	
05 Name of Contact Person Ken Petersen	06 Title of Contact Person Corporate Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Ken Petersen	Ken Petersen	04/15/2013
02 Title Corporate Controller and CAO		

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

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

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

GENERAL INFORMATION

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

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

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

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

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

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

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chief Executive Officer	J. LaMont Keen	675,000
3			
4	President & Chief Financial Officer	Darrel T. Anderson	420,000
5			
6	Executive Vice President, & Chief Operating Officer	Dan Minor	385,000
7			
8	Senior Vice President and General Counsel	Rex Blackburn	300,000
9			
10	Senior Vice President, Power Supply	Lisa Grow	260,000
11			
12	Senior Vice President, Finance & Treasurer	Steven Keen	260,000
13			
14	Vice President, Human Resources & Corporate Services	Luci McDonald	240,000
15			
16	Vice President and Chief Information Officer	Dennis Gribble	222,000
17			
18	Vice President, Customer Operations	Warren Kline	222,000
19			
20	Vice President, Public Affairs	Jeffrey Malmen	215,000
21			
22	Vice President, Chief Risk Officer	Lori Smith	215,000
23			
24	Vice President Delivery Engineering & Construction	Vern Porter	202,000
25			
26	Corporate Controller & Chief Accounting Officer	Ken Petersen	190,000
27			
28	Vice President, Regulatory Affairs	Gregory Said	172,500
29			
30	Corporate Secretary	Patrick Harrington	170,000
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32	Vice President, Supply Chain	Naomi Crafton-Shankel	170,000
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A Johansen	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
3		
4	Christine King	Standard Microsystems Corporation
5		80 Arkay Dr, Hauppauge, NY 11788
6		
7	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
8		
9	Stephen Allred	4642 W Dawson Dr Meridian, Id 83646
10		
11	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
12		
13	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	Richard G. Reiten (1)	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
17		Portland, Oregon 97204
18		
19	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
20		
21	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
22		
23	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
24		
25	Richard Dahl ***	11659 Presilla Road, Santa Rosa Valley Ca, 93012
26		
27	Dennis L Johnson (2)	United Heritage Life Insurance
28		707 E United Heritage Ct Ste 130 Meridian Idaho 83642
29		
30	(1) Retired from Board of Directors 5/17/12.	
31		
32	(2) Approved 3/21/2013	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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

Does the respondent have formula rates?

[X] Yes

[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	FERC Docket No. ER06-787-002,003
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201208275060	08/27/2012	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2012-2013 Annual	
3				informational filing	
4				under ER09-1641-000	
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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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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 #728 Langley Gulch Power Plant to Willis Tap added 49.05 miles.
   Changes to existing lines were:
   Line #404 Rebuilt approx 30 wire miles added approx .85 miles new line.
   Line #205 Deenergized transmisson line transferred to distribution 3.0 miles.
   Line #529 New transmission line to distribution 3.0 miles.
   Line #902-Line #433 Rerouted transmission to connect to new Justice station.
   Line #328-Line #250 Connection to new Montour station .26 wire miles.

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

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

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

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

7. None

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

9. See pages 123.19 to 123.21

10. None

11. None

12. None

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

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

management program.

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

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,922,872,974	4,473,847,185
3	Construction Work in Progress (107)	200-201	298,470,440	591,474,855
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,221,343,414	5,065,322,040
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,871,810,171	1,840,782,085
6	Net Utility Plant (Enter Total of line 4 less 5)		3,349,533,243	3,224,539,955
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,349,533,243	3,224,539,955
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,462,166	2,081,420
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	84,680,243	78,529,519
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		1,518	1,852
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		34,391,222	25,644,107
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		284,782	359,418
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		120,819,931	106,616,316
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,112,143	19,178,288
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		39,100	37,352
38	Temporary Cash Investments (136)		100,000	100,000
39	Notes Receivable (141)		72,492	94,776
40	Customer Accounts Receivable (142)		67,661,588	67,534,731
41	Other Accounts Receivable (143)		20,876,001	8,206,727
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,872,855	1,435,434
43	Notes Receivable from Associated Companies (145)		1,008,249	17,335,019
44	Accounts Receivable from Assoc. Companies (146)		63,847	0
45	Fuel Stock (151)	227	42,388,239	47,865,097
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	47,455,954	42,015,731
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,581,218	4,474,719
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		12,688,220	12,273,571
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		51,448,038	46,440,688
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		3,874,959	3,754,383
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		284,782	359,418
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		266,212,411	267,516,230
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		17,143,425	16,992,504
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,141,110,726	989,194,015
73	Prelim. Survey and Investigation Charges (Electric) (183)		819,409	491,041
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		1,364,037	630,208
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	53,913,850	50,880,202
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		14,921,058	13,613,712
82	Accumulated Deferred Income Taxes (190)	234	316,262,777	227,977,046
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,545,535,282	1,299,778,728
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,282,100,867	4,898,451,229

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	end of 2012/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		712,257,435	704,757,436
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	752,514,607	659,237,261
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	82,217,150	76,066,425
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-17,115,669	-11,622,052
16	Total Proprietary Capital (lines 2 through 15)		1,625,653,628	1,524,219,175
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,515,460,000	1,465,460,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	25,203,182	26,266,818
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		2,967,860	3,113,413
24	Total Long-Term Debt (lines 18 through 23)		1,537,695,322	1,488,613,405
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,479,272	1,924,461
29	Accumulated Provision for Pensions and Benefits (228.3)		425,887,098	366,648,491
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,261,891	0
31	Accumulated Provision for Rate Refunds (229)		45,672,853	33,145,395
32	Long-Term Portion of Derivative Instrument Liabilities		0	107,763
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		22,982,049	21,366,767
35	Total Other Noncurrent Liabilities (lines 26 through 34)		502,283,163	423,192,877
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		108,223,362	97,996,387
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		252,507	1,511,606
41	Customer Deposits (235)		1,966,205	10,799,095
42	Taxes Accrued (236)	262-263	8,109,787	4,895,725
43	Interest Accrued (237)		22,441,369	22,038,081
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,905,279	1,719,933
48	Miscellaneous Current and Accrued Liabilities (242)		30,534,183	33,498,725
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		1,054,644	4,706,863
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	107,763
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		174,487,336	177,058,652
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		13,261,592	19,747,984
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,896,604	70,840,400
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	17,982,872	27,530,572
60	Other Regulatory Liabilities (254)	278	69,401,786	96,483,245
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,080,279,413	933,326,224
64	Accum. Deferred Income Taxes-Other (283)		181,159,151	137,438,695
65	Total Deferred Credits (lines 56 through 64)		1,441,981,418	1,285,367,120
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,282,100,867	4,898,451,229

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

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,075,085,871	1,021,585,142		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	596,383,061	632,997,464		
5	Maintenance Expenses (402)	320-323	74,129,496	76,104,523		
6	Depreciation Expense (403)	336-337	116,113,891	113,001,742		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	317,075			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,483,540	6,764,513		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-13,255	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		39,784	28,099		
13	(Less) Regulatory Credits (407.4)		788,738			
14	Taxes Other Than Income Taxes (408.1)	262-263	30,488,808	28,894,715		
15	Income Taxes - Federal (409.1)	262-263	-14,482,226	-57,754,420		
16	- Other (409.1)	262-263	1,007,613	-803,160		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	239,208,729	116,679,418		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	200,111,787	99,841,847		
19	Investment Tax Credit Adj. - Net (411.4)	266	9,056,202	-1,131,934		
20	(Less) Gains from Disp. of Utility Plant (411.6)			-17,392		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		201,565	398,050		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		183,144			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		858,813,772	814,535,732		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		216,272,099	207,049,410		

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

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,075,085,871	1,021,585,142					2
						3
596,383,061	632,997,464					4
74,129,496	76,104,523					5
116,113,891	113,001,742					6
317,075						7
7,483,540	6,764,513					8
-13,255	-22,723					9
						10
						11
39,784	28,099					12
788,738						13
30,488,808	28,894,715					14
-14,482,226	-57,754,420					15
1,007,613	-803,160					16
239,208,729	116,679,418					17
200,111,787	99,841,847					18
9,056,202	-1,131,934					19
	-17,392					20
						21
201,565	398,050					22
						23
183,144						24
858,813,772	814,535,732					25
216,272,099	207,049,410					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		216,272,099	207,049,410		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,639,354	1,142,767		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,634,620	974,498		
33	Revenues From Nonutility Operations (417)		46,890	51,602		
34	(Less) Expenses of Nonutility Operations (417.1)		276,349	-18,126		
35	Nonoperating Rental Income (418)		-16,185	-3,285		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,150,725	5,967,745		
37	Interest and Dividend Income (419)		2,018,711	2,178,296		
38	Allowance for Other Funds Used During Construction (419.1)		22,433,417	25,484,071		
39	Miscellaneous Nonoperating Income (421)		1,990,234	1,428,531		
40	Gain on Disposition of Property (421.1)			57,199		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		32,352,177	35,350,554		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		717,897	718,718		
46	Life Insurance (426.2)		-14,029	-757,078		
47	Penalties (426.3)		-560,608	430,042		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,256,347	1,167,810		
49	Other Deductions (426.5)		7,533,768	6,579,000		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,933,375	8,138,492		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	24,640	23,238		
53	Income Taxes-Federal (409.2)	262-263	-102,078	-638,707		
54	Income Taxes-Other (409.2)	262-263	-161,217	-112,459		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	652,958	511,882		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,320,966	1,327,221		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,906,663	-1,543,267		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		25,325,465	28,755,329		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		78,922,057	79,348,955		
63	Amort. of Debt Disc. and Expense (428)		1,570,010	1,653,291		
64	Amortization of Loss on Reaquired Debt (428.1)		1,008,756	911,000		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		3,858,107	2,474,590		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		11,929,405	13,332,724		
70	Net Interest Charges (Total of lines 62 thru 69)		73,429,525	71,055,112		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		168,168,039	164,749,627		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		168,168,039	164,749,627		

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

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		657,027,573	558,128,446
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		162,017,314	158,781,882
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings on Hydro Projects under FPA	215.1	-1,193,716	(178,017)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-1,193,716	(178,017)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-68,739,968	(59,704,738)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-68,739,968	(59,704,738)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		749,111,203	657,027,573
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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

STATEMENT OF RETAINED EARNINGS

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

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

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

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	168,168,039	164,749,627
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	116,113,891	113,001,742
5	Amortization of	12,211,778	11,025,871
6			
7			
8	Deferred Income Taxes (Net)	40,671,950	-58,819,227
9	Investment Tax Credit Adjustment (Net)	5,813,188	-726,590
10	Net (Increase) Decrease in Receivables	-1,457,986	-2,125,936
11	Net (Increase) Decrease in Inventory	930,136	-21,207,643
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	12,717,237	22,896,607
14	Net (Increase) Decrease in Other Regulatory Assets	-42,236,101	23,708,446
15	Net Increase (Decrease) in Other Regulatory Liabilities	-11,230,901	44,336,626
16	(Less) Allowance for Other Funds Used During Construction	22,433,417	25,484,072
17	(Less) Undistributed Earnings from Subsidiary Companies	6,150,724	5,967,745
18	Other (provide details in footnote):	-31,590,882	27,407,253
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	241,526,208	292,794,959
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-227,831,534	-324,431,776
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	11,929,405	13,332,724
31	Other (provide details in footnote):	2,738,701	6,314,273
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-237,022,238	-331,450,227
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-7,000,000	
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	22,284	208,367
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	16,672,022	-493,891
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-227,327,932	-331,735,751
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	150,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote): Capital Infusion from IDACORP	7,500,000	16,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	157,500,000	16,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-101,063,636	-121,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,959,067	-1,207,914
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-68,739,968	-59,704,738
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-16,262,671	-165,976,288
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,064,395	-204,917,080
87			
88	Cash and Cash Equivalents at Beginning of Period	19,315,638	224,232,718
89			
90	Cash and Cash Equivalents at End of period	17,251,243	19,315,638

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

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

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

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

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

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

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

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

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

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

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

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

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power Company (Idaho Power) is the principal operating subsidiary of IDACORP Inc. (IDACORP), a holding company formed in 1998. Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of Idaho Power and have been prepared in accordance with the accounting requirements of the FERC as set forth in the applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, Idaho Power accounts for its investments in its majority-owned subsidiary on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiary as required by U.S GAAP. The accompanying financial statements include Idaho Power's proportionate share of the utility plant and related operations resulting from its interest in jointly-owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) regulatory assets and liabilities (4) deferred income taxes, (5) income tax expense and (6) non-utility revenues (7) accrued taxes.

Management Estimates

Management makes estimates and assumptions when preparing these financial statements. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, litigation, asset impairment, income taxes, unbilled revenues, and bad debt. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual results could differ from those estimates.

System of Accounts

The accounting records of Idaho Power conform to the Uniform System of Accounts prescribed by the FERC and adopted by the public utility commissions of Idaho, Oregon, and Wyoming.

Regulation of Utility Operations

Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable. Other receivables are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2012 and 2011. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options, and swaps are used to manage exposure to commodity price risk in the electricity and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet unless they are designated as normal purchases and normal sales. Idaho Power’s physical forward contracts are designated as normal purchases and normal sales with the exception of forward contracts for the purchase of natural gas for use at Idaho Power’s natural gas generation facilities. The objective of Idaho Power's risk management program is to mitigate the price risk associated with the purchase and sale of electricity and natural gas. Because of Idaho Power’s regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues related to Idaho Power’s sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision, and similar overhead items. Repair and maintenance costs associated with planned major maintenance are expensed as the costs are incurred, as are maintenance and repairs of property and replacements and renewals of items determined to be less than units of property. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.75 percent in 2012 and 2.83 percent in 2011.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no material impairments of these assets in 2012 or 2011.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the Hells Canyon Complex relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power's weighted-average monthly AFUDC rates for 2012 and 2011 were 7.7 percent and 7.8 percent, respectively.

Income Taxes

Idaho Power accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method (commonly referred to as normalized accounting), deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities at the beginning and end of the period. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not provide deferred income taxes for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are provided for other temporary differences unless accounted for using flow-through.

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

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

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

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

Other Accounting Policies

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

2. INCOME TAXES

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

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

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

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

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

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

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP. See Note 1 for further discussion of accounting policies related to income taxes.

Uncertain Tax Positions

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

	2012	2011
Balance at January 1,	$ —	$ 74,436
Additions for tax positions of the current year	—	—
Additions for tax positions of prior years	—	—
Reductions for tax positions of prior years	—	(66,379)
Settlements with taxing authorities	—	(8,057)
Balance at December 31,	$ —	$ —

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Idaho Power recognized no interest expense in 2012 and a net reduction of $0.2 million in 2011. Accrued interest was zero as of December 31, 2012 and 2011. No penalties are accrued.

Idaho Power is subject to examination by its major tax jurisdictions - U.S. federal and the state of Idaho. The open tax years for examination are 2012 for federal and 2009-2012 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2012, the IRS completed its examination of IDACORP's 2011 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no material tax uncertainties for 2012 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

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

In the third quarter of 2012 Idaho Power completed an income tax accounting method change for its 2011 tax year related to a portion of the capitalized repairs method. The change was made pursuant to Revenue Procedure 2011-43 to bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric transmission and distribution property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP's 2011 consolidated federal income tax return. The IRS approved the method change prior to the filing of the return as part of IDACORP's 2011 CAP examination. A $7.8 million tax benefit was recognized in 2012 for the filed deduction related to the cumulative method change adjustment for years prior to 2011.

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

Tax Accounting Method Change for Uniform Capitalization

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

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

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized the remaining $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

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

3. REGULATORY MATTERS

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining Idaho Power's results of operations and financial condition.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power’s regulatory assets and liabilities (in thousands of dollars):

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

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power’s pension and postretirement benefit plans, which are discussed in Note 10.
(3) These items are discussed in more detail in this Note 3.
(4) Asset retirement obligations and removal costs are discussed in Note 12.
(5) Mark-to-market assets and liabilities are discussed in Note 15.

Idaho Power’s regulatory assets and liabilities are amortized over the period in which they are reflected in customer rates. In the event that recovery of Idaho Power’s costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power's operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a significant financial impact.

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes (including PURPA power purchases), and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments consist of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

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

Effective Date	$ Change (millions)	Notes
June 1, 2012	$ 43.0	The PCA rate increase was offset by $27.1 million to be shared with customers pursuant to the revenue sharing order described below, resulting in a net rate increase of $15.9 million for these orders.
June 1, 2011	$ (40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of the three years ended December 31, 2012 and 2011 are summarized in the table that follows.

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

Idaho Regulatory Matters

2011 Idaho General Rate Case Settlement: On June 1, 2011, Idaho Power filed a general rate case with the IPUC requesting approximately $82.6 million in additional Idaho jurisdiction annual revenues through base rates. On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case, and on December 30, 2011 the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 2011 order provided for a 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity and did not impose a moratorium on Idaho Power's filing a general rate case at a future date.

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

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

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

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

June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

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

December 2011 Idaho Settlement Agreement: The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power extending, with modifications, some of the provisions of the January 2010 settlement agreement. The settlement stipulation provided that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA adjustment; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

The December 2011 settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the December 2011 settlement stipulation further provided that Idaho Power would allocate to customers as a reduction to the pension regulatory asset 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE.

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

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

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

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

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

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

Cost Recovery for Langley Gulch Power Plant: On March 2, 2012, Idaho Power filed an application with the IPUC requesting an increase in annual Idaho-jurisdiction base rates of $59.9 million for recovery of Idaho Power's investment and associated costs for the Langley Gulch power plant, which became commercially available on June 29, 2012. Idaho Power's application stated that its estimated investment in the plant through June 2012 was approximately $398 million. After the impact of depreciation, deferred income taxes, amounts currently included in rates, and an Idaho-jurisdictional cost allocation, Idaho Power's application requested a $336.7 million increase in Idaho-jurisdiction rate base. Idaho Power's requested base rate increase was based on an overall rate of return of 7.86 percent, as authorized by a prior IPUC order. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Inclusion of the Langley Gulch power plant in Idaho Power's power supply portfolio also resulted in a change in Idaho Power's power supply cost assumptions. Accordingly, in the Langley Gulch order the IPUC also updated Idaho Power's LCAR to $17.64 per MWh, effective July 1, 2012.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2012, Idaho Power's deferral balance associated with the Idaho-jurisdiction was $62.9 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. Idaho Power has made substantial contributions to its defined benefit pension plan in recent years. The single largest contribution occurred in September 2010, when Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount. The amount contributed over the minimum required contribution was intended to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power's application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan and during 2012 contributed $44.3 million.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho

Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. In the 2012 PCA filing, $14.5 million of certain demand response program costs were shifted from the rider mechanism to the PCA mechanism, as these costs are closely related to and directly impact the other power supply costs collected through the PCA.

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

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

The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Cost Recovery for Cessation of Boardman Coal-Fired Operations: In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The plan results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. In response to an application filed by Idaho Power, on February 15, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early plant shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On May 17, 2012, the IPUC issued an order approving a $1.5 million annual increase in Idaho-jurisdiction base rates, with new rates effective June 1, 2012. As of December 31, 2012, Idaho Power's net book value in the Boardman plant was $23.1 million.

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

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated service life estimates and net salvage percentages for all plant assets, and adjust Idaho-jurisdiction base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdiction base rates. On May 31, 2012, the IPUC issued an order approving a settlement stipulation agreed to by Idaho Power, the IPUC Staff, and a large industrial customer of Idaho Power, which provided for a $1.3 million annual decrease in Idaho-jurisdiction base rates, effective June 1, 2012.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues and an authorized rate of return on equity of 10.5 percent, with an Oregon retail rate base of approximately $121.9 million. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolved all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The OPUC approved the settlement stipulation on February 23, 2012, which provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger plant.

Cost Recovery for Langley Gulch Power Plant: On March 9, 2012, Idaho Power filed an application with the OPUC requesting an annual increase in Oregon jurisdiction revenues of $3.0 million for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates effective October 1, 2012.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

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

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

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

4. LONG-TERM DEBT

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

	2012	2011
First mortgage bonds:		
4.75% Series due 2012	$ —	$ 100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
2.95% Series Due 2022	75,000	—
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	—
Total first mortgage bonds	1,345,000	1,295,000
Pollution control revenue bonds:		
5.15% Series due 2024(1)	49,800	49,800
5.25% Series due 2026(1)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	5,318	6,382
Unamortized premium/discount - net	(2,967)	(3,113)
Total Idaho Power outstanding debt(2)	1,537,696	1,488,614
Current maturities of long-term debt	(71,064)	(101,064)
Total long-term debt	$ 1,466,632	$ 1,387,550

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2012 to $1.511 billion.

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

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

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

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. In August 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, medium-term notes, Series I maturing in August 2020, and $100 million of 4.85% first mortgage bonds, medium-term notes, Series I maturing in August 2040. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022, and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042. The first mortgage bonds were issued under Idaho Power's shelf registration statement. As a result of these issuances, as of December 31, 2012, $150 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

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

***Mortgage*:** As of December 31, 2012, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

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

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

5. NOTES PAYABLE

Credit Facilities

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

The interest rate for any borrowings under the facility is based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, an applicable margin. The margin is based on Idaho Power's senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreement. Under the facility, Idaho Power pays a facility fee on the commitment based on Idaho Power's credit rating for senior unsecured long-term debt securities. While the credit facility provides for an original maturity date of October 26, 2016, the credit agreement grants Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On October 12, 2012, Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity date under the agreement to October 26, 2017.

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

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

6. COMMON STOCK

Idaho Power Common Stock

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

Restrictions on Dividends

A covenant under Idaho Power's credit facility requires Idaho Power to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. Idaho Power's ability to pay dividends on its common stock held by IDACORP is limited to the extent payment of such dividends would violate the covenants in the credit facility or Idaho Power's Revised Code of Conduct. At December 31, 2012, the leverage ratio for Idaho Power was 49 percent. Based on these restrictions, Idaho Power's dividends were limited to $794 million at December 31, 2012. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to Idaho Power from any material subsidiary. At December 31, 2012, Idaho Power was in compliance with all facility covenants.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2012, Idaho Power's common equity capital was 51 percent of its total adjusted capital. Further, Idaho Power must obtain the approval of the OPUC before it may directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. As of the date of this report, Idaho Power has no shares of preferred stock outstanding.

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

In accordance with Section 10(d) of the Federal Power Act, Idaho Power has $3.4 million of amortization reserves established for certain of its licensed hydroelectric facilities.

7. STOCK-BASED COMPENSATION

Through its parent company IDACORP, Idaho Power has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2012, the maximum number of shares available under the LTICP and RSP were 1,371,305 and 15,796, respectively.

Stock Awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the closing market price of common stock on the grant date and is charged to compensation expense over the vesting period, based on the number of shares expected to vest.

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. Based on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The performance awards are based on two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of these awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of these awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock and performance share activity is presented below.

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

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

In 2012, a total of 14,820 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $40.48 per share. Directors elected to defer receipt of 7,410 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2012, all compensation costs have been recognized. Idaho Power uses IDACORP's original issue and/or treasury shares to satisfy exercised options.

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

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

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

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

Compensation Expense: The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to Idaho Power for those costs associated with Idaho Power's employees (in thousands of dollars):

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

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

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

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

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

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

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

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

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on historical experience and the evaluation of the specific indemnities. As of December 31, 2012, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on the consolidated balance sheet with respect to these indemnification obligations.

9. CONTINGENCIES

Idaho Power has in the past and expects in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 9. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, Idaho Power establishes an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. Idaho Power monitors those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, thereof, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, Idaho Power does not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, Idaho Power's accrual for loss contingencies is not material to the financial statements as a whole; however, future accruals could be material in a given period. Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. As available information changes, the matters for which Idaho Power is able to estimate the loss may change, and the estimates themselves may change. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending petitions and predict that these matters will not have a material adverse effect on Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC characterized these ripple claims as "speculative." However, the FERC refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve a settlement that provided for waivers of all claims in those proceedings, despite only limited objections from two market participants. Idaho Power and IESCo have petitioned for review of the FERC's decision. Based on its evaluation of the merits of such claims and the inability to estimate any potential exposure should the claims ultimately have merit, Idaho Power and IESCo have no remaining amount accrued for financial statement purposes relating to the western energy proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Water Rights - Snake River Basin Adjudication

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

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

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

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

Other Proceedings

Idaho Power is party to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report Idaho Power believes that resolution of those matters will not have a material adverse effect on the consolidated financial statements. Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

10. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. Through its parent company IDACORP, Idaho Power also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

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

Idaho Power’s funding policy for its pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2012 and 2011 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

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

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. These investments totaled approximately $50.4 million and $41.2 million at December 31, 2012 and 2011, respectively, and are reflected in Investments and Company-owned life insurance on the consolidated balance sheets.

The table that follows shows the components of net periodic benefit cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan		SMSP	
	2012	2011	2012	2011
Service cost	$ 25,571	$ 20,478	$ 2,151	$ 1,950
Interest cost	31,489	30,322	3,218	3,094
Expected return on assets	(31,737)	(32,322)	—	—
Amortization of net loss	14,114	8,673	1,530	1,293
Amortization of prior service cost	347	519	212	242

Net periodic pension cost	39,784	27,670	7,111	6,579
Adjustments due to the effects of regulation(1)	(5,860)	6,662	—	—
Net periodic benefit cost recognized for financial reporting	$ 33,924	$ 34,332	$ 7,111	$ 6,579

(1) Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's revenue sharing mechanism approved by the IPUC, which resulted in additional Idaho pension expense of $14.6 million and $20.3 million in 2012 and 2011, respectively.

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

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

In 2013, Idaho Power expects to recognize as components of net periodic benefit cost $20.4 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2012, relating to the pension plan and SMSP. This amount consists of $17.0 million of amortization of net loss and $0.4 million of amortization of prior service cost for the pension plan, and $2.8 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

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

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

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

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

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

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

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

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

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

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

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

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

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

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

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

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

Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Pension Plan		SMSP		Postretirement Benefits	
	2012	2011	2012	2011	2012	2011
Discount rate	4.20%	4.90%	4.15%	5.10%	4.20%	5.05%
Rate of compensation increase[1]	4.35%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.5%	7.0%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2012	12/31/2011	12/31/2012	12/31/2011	12/31/2012	12/31/2011

[1] The 2012 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

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

	Pension Plan		SMSP		Postretirement Benefit	
	2012	2011	2012	2011	2012	2011
Discount rate	4.90%	5.40%	5.10 %	5.40%	5.05 %	5.40 %
Expected long-term rate of return on assets	7.75%	8.25%	—	—	7.25 %	8.25 %
Rate of compensation increase	4.35%	4.50%	4.50 %	4.50%	—	—
Medical trend rate	—	—	—	—	6.5 %	7.0 %
Dental trend rate	—	—	—	—	5.0 %	5.0 %

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.5 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2012 (in thousands of dollars):

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

Plan Assets

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

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

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

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

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

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

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

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

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

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

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2012				
Pension assets:				
Cash and cash equivalents	$ 7,628	$ —	$ —	$ 7,628
Short-term bonds	—	12,373	—	12,373
Long-term bonds	—	96,671	—	96,671
Equity Securities: Large-Cap	57,526	—	—	57,526
Equity Securities: Mid-Cap	19,944	16,780	—	36,724
Equity Securities: Small-Cap	36,409	—	—	36,409
Equity Securities: Micro-Cap	19,923	—	—	19,923
Equity Securities: International	19,461	59,142	—	78,603
Equity Securities: Emerging Markets	3,101	21,370	—	24,471
Equity Securities: Market Neutral	7,675	—	—	7,675
Real estate	—	—	27,874	27,874
Private market investments	—	—	30,507	30,507
Commodities funds	1,420	23,058	—	24,478
Total pension assets	$ 173,087	$ 229,394	$ 58,381	$ 460,862
Postretirement assets(1)	$ 325	$ 33,062	$ —	$ 33,387

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

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

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

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

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2011	$ 29,932	$ 22,069	$ 52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	27,786	25,119	52,905
Realized gains	95	742	837
Unrealized gains	1,387	1,271	2,658
Purchases	1,779	742	2,521
Sales	(540)	—	(540)
Ending balance - December 31, 2012	$ 30,507	$ 27,874	$ 58,381

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

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

Level 3 Real Estate: Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

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

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

Employee Savings Plan

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

Post-employment Benefits

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

11. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power’s utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2012 and 2011 (in thousands of dollars):

	2012		2011	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,217,334	2.36%	$ 1,832,287	2.22%
Transmission	931,403	2.02%	871,784	2.06%

Distribution	1,411,740	2.89%	1,434,925	3.12%
General and Other	355,295	6.47%	327,877	7.32%
Total in service	4,915,772	2.75%	4,466,873	2.83%
Accumulated provision for depreciation	(1,871,810)		(1,840,782)	
In service - net	$ 3,043,962		$ 2,626,091	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses are included in the Consolidated Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2012 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW (1)
Jim Bridger Units 1-4	Rock Springs, WY	$ 542,894	$ 16,528	$ 280,875	33	771
Boardman	Boardman, OR	79,031	1,355	55,940	10	64
Valmy Units 1 and 2	Winnemucca, NV	353,541	10,163	198,190	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $75 million and $65 million in 2012 and 2011, respectively.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9 million in both 2012 and 2011.

12. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, Idaho Power records regulatory assets or liabilities instead of accretion, depreciation, and gains or losses, as approved by the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

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

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

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the costs recorded as regulatory liabilities on Idaho Power's Consolidated Balance Sheet as of December 31, 2012 and 2011.

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

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

13. INVESTMENTS

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

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

Investments in Equity Securities

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

The table below summarizes investments in equity securities by Idaho Power as of December 31, 2012 and December 31, 2011 (in thousands of dollars).

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

At the end of each reporting period, Idaho Power analyzes securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2012, there were no securities in an unrealized loss position. At December 31, 2011, one security was in an immaterial unrealized loss position. No other-than-temporary impairment was recognized for this security due to the limited severity and duration of the unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2012 or 2011.

14. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. The objective of Idaho Power's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

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

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges under derivative accounting guidance. Idaho Power offsets fair value amounts recognized on its balance sheet related to derivative instruments executed with the same counterparty under the same master netting agreement.

Derivative Instruments Summary

The tables below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets at December 31, 2012 and 2011 (in thousands of dollars).

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

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

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

(1) Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 15 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

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

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

Credit Risk

At December 31, 2012, Idaho Power did not have material credit exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are under Western Systems Power Pool agreements, physical gas contracts are under North American Energy Standards Board contracts, and financial transactions are under International Swaps and Derivatives Association, Inc. contracts. These contracts all contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2012, was $2.4 million. Idaho Power posted no collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, Idaho Power would have been required to post $5.9 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS

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

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

- Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that Idaho Power has the ability to access.

- Level 2: Financial assets and liabilities whose values are based on:
  - a) quoted prices for similar assets or liabilities in active markets;
  - b) quoted prices for identical or similar assets or liabilities in non-active markets;
  - c) pricing models whose inputs are observable for substantially the full term of the asset or liability; and
  - d) pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

  Idaho Power Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data.

- Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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

The table below presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2012 and 2011 (in thousands of dollars). Idaho Power's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels for the years presented.

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

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2012 and 2011, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for long-term debt is based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

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

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

16. RELATED PARTY TRANSACTIONS

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

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million to Ida-West in both 2012 and 2011.

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

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

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

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

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

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(9,567,515)		
2			934,902		
3			(2,989,439)		
4			(2,054,537)	164,749,627	162,695,090
5			(11,622,052)		
6			(11,622,052)		
7			1,060,888		
8			(6,554,505)		
9			(5,493,617)	168,168,039	162,674,422
10			(17,115,669)		

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

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,915,771,669	4,915,771,669
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,915,771,669	4,915,771,669
9	Leased to Others		
10	Held for Future Use	7,101,305	7,101,305
11	Construction Work in Progress	298,470,440	298,470,440
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,221,343,414	5,221,343,414
14	Accum Prov for Depr, Amort, & Depl	1,871,810,171	1,871,810,171
15	Net Utility Plant (13 less 14)	3,349,533,243	3,349,533,243
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,848,861,113	1,848,861,113
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,949,058	22,949,058
22	Total In Service (18 thru 21)	1,871,810,171	1,871,810,171
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,871,810,171	1,871,810,171

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

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	23,171,392	5,821,094
4	(303) Miscellaneous Intangible Plant	34,317,102	3,996,149
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	57,494,197	9,817,243
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,707,109	
9	(311) Structures and Improvements	143,758,647	4,462,234
10	(312) Boiler Plant Equipment	569,484,225	6,942,778
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	150,650,806	1,837,467
13	(315) Accessory Electric Equipment	60,126,130	8,217,762
14	(316) Misc. Power Plant Equipment	15,180,475	1,700,368
15	(317) Asset Retirement Costs for Steam Production	8,005,226	2,208,288
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	948,912,618	25,368,897
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	30,132,870	709,417
28	(331) Structures and Improvements	156,227,013	1,306,025
29	(332) Reservoirs, Dams, and Waterways	252,890,100	288,688
30	(333) Water Wheels, Turbines, and Generators	197,920,861	3,082,590
31	(334) Accessory Electric Equipment	45,854,367	1,142,182
32	(335) Misc. Power PLant Equipment	19,081,434	1,372,330
33	(336) Roads, Railroads, and Bridges	8,112,491	5,122
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	710,219,136	7,906,354
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	7,169,595	125,884,758
39	(342) Fuel Holders, Products, and Accessories	4,445,866	3,542,032
40	(343) Prime Movers	98,951,696	127,879,002
41	(344) Generators	31,681,900	41,765,594
42	(345) Accessory Electric Equipment	25,077,582	70,480,766
43	(346) Misc. Power Plant Equipment	3,138,437	2,600,177
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	173,155,082	372,152,329
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,832,286,836	405,427,580

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	35,130,605	445,557
49	(352) Structures and Improvements	57,994,797	12,150,635
50	(353) Station Equipment	351,924,749	14,049,079
51	(354) Towers and Fixtures	147,491,416	7,679,305
52	(355) Poles and Fixtures	107,026,913	13,764,963
53	(356) Overhead Conductors and Devices	171,801,963	13,274,942
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	413,346	-23,080
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	871,783,789	61,341,401
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,423,471	-648,228
61	(361) Structures and Improvements	32,336,183	-956,431
62	(362) Station Equipment	194,190,240	-3,641,870
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	228,880,444	2,946,117
65	(365) Overhead Conductors and Devices	122,536,891	3,105,791
66	(366) Underground Conduit	47,989,345	-1,002,615
67	(367) Underground Conductors and Devices	196,700,971	1,730,268
68	(368) Line Transformers	429,419,556	26,406,882
69	(369) Services	57,225,209	-73,102
70	(370) Meters	112,429,849	570,493
71	(371) Installations on Customer Premises	2,754,620	166,375
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,394,855	130,714
74	(374) Asset Retirement Costs for Distribution Plant	643,639	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,434,925,273	28,734,394
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	16,128,658	-8,453
87	(390) Structures and Improvements	84,984,787	8,918,686
88	(391) Office Furniture and Equipment	40,558,356	10,610,178
89	(392) Transportation Equipment	60,978,129	5,524,778
90	(393) Stores Equipment	1,600,036	285,525
91	(394) Tools, Shop and Garage Equipment	6,054,996	515,974
92	(395) Laboratory Equipment	11,866,322	643,136
93	(396) Power Operated Equipment	10,696,486	833,783
94	(397) Communication Equipment	32,714,344	7,877,762
95	(398) Miscellaneous Equipment	5,255,018	401,277
96	SUBTOTAL (Enter Total of lines 86 thru 95)	270,837,132	35,602,646
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	270,837,132	35,602,646
100	TOTAL (Accounts 101 and 106)	4,467,327,227	540,923,264
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,467,327,227	540,923,264

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

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
60,000			28,932,486		3
7,062,241			31,251,010		4
7,122,241			60,189,199		5
					6
					7
			1,707,109		8
510,858			147,710,023		9
13,077,075			563,349,928		10
					11
4,716,265			147,772,008		12
144,087			68,199,805		13
1,163,072			15,717,771		14
			10,213,514		15
19,611,357			954,670,158		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			30,842,287		27
15,258			157,517,780		28
34,486			253,144,302		29
159,917			200,843,534		30
349,138			46,647,411		31
162,205			20,291,559		32
			8,117,613		33
					34
721,004			717,404,486		35
					36
			2,690,006		37
28,341			133,026,012		38
			7,987,898		39
20,000			226,810,698		40
			73,447,494		41
			95,558,348		42
			5,738,614		43
					44
48,341			545,259,070		45
20,380,702			2,217,333,714		46

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			35,576,162		48
8,541			70,136,891		49
529,861		-89,005	365,354,962		50
74,995			155,095,726		51
435,295			120,356,581		52
584,891			184,492,014		53
					54
					55
			390,266		56
					57
1,633,583		-89,005	931,402,602		58
					59
			4,775,243		60
25,585			31,354,167		61
945,164		61,696	189,664,902		62
					63
1,470,555			230,356,006		64
1,630,230			124,012,452		65
152,847			46,833,883		66
699,100			197,732,139		67
4,614,794			451,211,644		68
298,753			56,853,354		69
42,067,815			70,932,527		70
55,841			2,865,154		71
					72
20,358			4,505,211		73
			643,639		74
51,981,042		61,696	1,411,740,321		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			16,120,205		86
250,021			93,653,452		87
8,373,808			42,794,726		88
1,612,476			64,890,431		89
7,739			1,877,822		90
105,260			6,465,710		91
254,363			12,255,095		92
34,346			11,495,923		93
689,228		27,309	39,930,187		94
34,013			5,622,282		95
11,361,254		27,309	295,105,833		96
					97
					98
11,361,254		27,309	295,105,833		99
92,478,822			4,915,771,669		100
					101
					102
					103
92,478,822			4,915,771,669		104

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

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		655,550
3	Production			112,703
4	Transmission Stations			429,822
5	Transmission Lines			195,517
6	Distribution Stations			1,078,591
7	Beacon Light Substation	12/30/02		465,662
8	Homedale Substation	2/29/08		109,453
9	North River Operations Center	1/31/08		2,630,412
10	Line #854 500 Kv	3/31/09		308,066
11				
12				
13				
14	Column B if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Transmission Stations			199,069
24	Distribution Stations			72,016
25	Homedale Substation	2/29/08		215,719
26	Beacon Light Substation	12/30/02		555,940
27				
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42				
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44				
45				
46				
47	Total			7,101,305

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

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ROLLUP RELIC COST BROWNLEE	61,547,907
2	ROLLUP RELIC COST HELLS CANYON	42,037,561
3	BOARDMAN - HEMINGWAY 500 KV LI	26,705,806
4	GATEWAY WEST 500KV LINE	20,908,755
5	ROLLUP RELIC COST OXBOW	19,419,114
6	HELLS CANYON RELICENSING OUTSI	15,674,400
7	NIAGARA SPRINGS HATCHERY EXPAN	9,194,254
8	BRIDGER 2008C123LP U1 TURBINE	8,911,069
9	WQ - ONGOING HELLS CANYON RELI	6,829,646
10	CIAC LIABILITY RECLASS	6,046,206
11	BUILD NEW JUSTICE TRANSMISSION	5,082,098
12	RIVER ENG.-HELLS CANYON CONTIN	4,693,433
13	BOBN REPLACE C233 AND C234 SER	4,297,924
14	BRIDGER UNDISTRIBUTED WORK ORD	3,646,399
15	B2H PERMITTING 11/1/2011 & FOR	3,139,305
16	VALMY UNDISTRIBUTED WORK ORDER	2,357,929
17	B2H TLINE CONSTRUCTION COSTS	1,935,953
18	LEGAL DEPT. LABOR FOR RELICENS	1,852,244
19	VALMY 98250588 DUST COLLECTOR	1,851,747
20	REL-HCC OREGON REAUTHORIZATION	1,741,966
21	BCW - UG FIBER INSTALLATION	1,718,795
22	VALMY 98301759 V1 UTILITY MACT	1,695,010
23	SGIG - INTEGRATIONS	1,554,085
24	SGIG - OUTAGE MANAGEMENT SYSTE	1,411,182
25	2012 PC PURCHASES - CUSTOMER O	1,319,812
26	IPCO/ / 2011 DOWNTOWN CAPITAL	1,316,681
27	KPRT1002: EVAL SYNCHRONOUS CON	1,201,239
28	OBPR LOCAL SERVICE UPGRADE	1,147,272
29	SGIG CUSTOMER DATA MART	1,081,974
30	OTHER MINOR PROJECTS UNDER $1,000,000	38,150,674
31		
32		
33		
34		
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41		
42		
43	TOTAL	298,470,440

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,818,635,521	1,818,635,521		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	116,113,891	116,113,891		
4	(403.1) Depreciation Expense for Asset Retirement Costs	317,075	317,075		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,189,325	3,189,325		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	100,439	100,439		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	119,720,730	119,720,730		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	85,356,581	85,356,581		
13	Cost of Removal	7,686,282	7,686,282		
14	Salvage (Credit)	2,327,547	2,327,547		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	90,715,316	90,715,316		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	CIAC, Reserve adj and Asset Retireme	1,220,178	1,220,178		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,848,861,113	1,848,861,113		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	529,534,301	529,534,301		
21	Nuclear Production				
22	Hydraulic Production-Conventional	366,042,954	366,042,954		
23	Hydraulic Production-Pumped Storage				
24	Other Production	41,316,874	41,316,874		
25	Transmission	285,425,520	285,425,520		
26	Distribution	516,534,664	516,534,664		
27	Regional Transmission and Market Operation				
28	General	110,006,800	110,006,800		
29	TOTAL (Enter Total of lines 20 thru 28)	1,848,861,113	1,848,861,113		

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			76,066,425
5				
6	Subtotal Idaho Energy Resources Company			78,529,519
7				
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41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	78,529,519

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
6,150,725		82,217,149		4
				5
6,150,725		84,680,243		6
				7
				8
				9
				10
				11
				12
				13
				14
				15
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				31
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				37
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				39
				40
				41
6,150,725		84,680,243		42

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

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	47,865,097	42,388,239	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,808,824	15,899,274	
8	Transmission Plant (Estimated)	12,917,846	12,836,658	
9	Distribution Plant (Estimated)	13,087,873	17,335,350	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,201,188	1,384,672	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	42,015,731	47,455,954	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	4,474,719	3,581,218	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	94,355,547	93,425,411	

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

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	IPC TRANS SIS 74705988,74705990,				
3	74705993,7470995, 74706017		186623	8,661	186623
4	IPC TRANS SIS 76655746	2,514	186623	(2,514)	186623
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LAVA BEDS WIND PARK	1,324	186623	10,871	186623
23	HIDDEN HOLLOW EXPANSION GI#291		186623	(2,247)	186623
24	WHEATGRASS RIDGE WIND PROJECT 294	943	186623	78,847	186623
25	COTTEREL MTN WIND PROJECT 302	101	186623	73,413	186623
26	ADAMS COUNTY BIOMASS GI#304		186623	26,652	186623
27	SWAGER FARMS GI#307	3,823	186623	12,427	186623
28	DOUBLE B DAIRY GI#308	179	186623	6,517	186623
29	GRAND VIEW SOLAR GI#312	657	186623	13,711	186623
30	YELLOWSTONE PWR GI#315		186623	18,586	186623
31	JACK RANCH WIND GI 322	5,847	186623	28,322	186623
32	SALMON CREEK GI 325	1,990	186623	31,366	186623
33	TUMBLE WEED 34.5 GI 332		186623	(6,006)	186623
34	HIGH MESA WIND GI 334	4,020	186623	89,366	186623
35	DYNAMIS LANDFILL GI 344	17,086	186623	1,235	186623
36	MURPHY FLAT WIND GI 346	385	186623	99,615	186623
37	NOTCH BUTTE GI 349	13,602	186623	(5,839)	186623
38	RAINBOW WEST GI 352	14,645	186623	16,557	186623
39	SALMON FALLS WIND GI 357		186623	98,158	186623
40	NOTCHBUTTE GI 359		186623	17,414	186623

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

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	COLEMAN HYDRO GI 362	266	186623	13,662	186623
23	GRAND VIEW SOLAR TWO GI 369	8,881	186623	(10,000)	186623
24	MEADOW CREEK WIND GI 370		186623	139,096	186623
25	MTNAIR EXPANSION GI 373-378		186623	28,899	186623
26	BANNOCK COUNTY LANDFILL GI 380	7,517	186623	1,253	186623
27	FARGO DROP GI 382	(4,348)	186623	7,023	186623
28	BETASEED BIOGAS GI 383		186623	(1,913)	186623
29	JETTCREEK WINDFARM GI 384	3,252	186623	(2,252)	186623
30	PROSPECTOR WINDFARM GI 385		186623	1,000	186623
31	BENSON CREEK WINDFARM GI 386		186623	1,000	186623
32	DURBIN CREEK WINDFARM GI 387		186623	1,000	186623
33	MIDPOINT SOLAR GI 388	6,861	186623	(6,861)	186623
34	AMALSUGAR PAUL GI 389	3,067	186623	(1,000)	186623
35	EAGLE VIEW DAIRY GI 390	11,487	186623	(17,686)	186623
36	GRANDVIEW SOLAR 3 GI 394	2,616	186623	(16,000)	186623
37	GRANDVIEW SOLAR 4 GI 395	13,268	186623	(16,000)	186623
38	MURPHY FLAT WIND FARM	7,112	186623	(20,000)	186623
39	BLACK CANYON BLISS HYDRO		186623	(500)	186623
40	BENSON CREEK WINDFARM GI 401		186623	(51,000)	186623

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

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	DURBIN CREEK WINDFARM GI 402		186623	(1,000)	186623
23	JETT CREEK WINDFARM GI 403		186623	(1,000)	186623
24	PROSPECTOR WINDFARM GI 404		186623	(1,000)	186623
25	WILLOW CREEK WINDFARM GI 405		186623	(1,000)	186623
26	SHOSHONE FALLS GI 136	47,511	186623		186623
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
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) 04/15/2013	Year/Period of Report End of 2012/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Asset Retirement Obligations (182341)	15,557,422	475,084	1823/230	2,448,633	13,583,873
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	ASC 815 Mark to Market - ST (182330)	4,599,099	15,345,805	244	18,890,261	1,054,643
5						
6	ASC 815 Mark to Market - LT (182333)	107,763	754,454	244	862,217	
7						
8	Regulatory Unfunded (182322)	603,772,178	74,023,292			677,795,470
9	Accum Deferred Income Noncurrent					
10						
11	PCA Deferral Idaho - IPUC Order #27660		129,900,586	Various	77,551,097	52,349,489
12	(Amort period 06/12 thru 05/13) (182323)					
13						
14	PCA Prior Year Deferral Idaho - IPUC Order #27660		117,190,627	Various	137,659,759	-20,469,132
15	(Amort period 06/11 thru 05/12) (182324)					
16						
17	Fixed Cost Adjusment (FCA) (182302)	10,273,296	15,154,508	1823	16,597,586	8,830,218
18	IPUC Order #30267 (amort period 06/12 thru 05/13)					
19						
20	Prior Year FCA IPUC Order #30267 (182309)	4,183,172	34,887,291	1823/400	34,483,059	4,587,404
21						
22	FERC Grid West Expense (182304)	111,728		401	83,796	27,932
23	ER08-629-000 (amort period 05/08 thru 04/13)					
24						
25	AOCI Impact of Unfunded Post Retirement Liability	15,536,177	2,440,534	228	2,081,396	15,895,315
26	IPUC Order #30256 (182306)					
27						
28	Oregon Pension Expense Capitalized	1,345,487	609,906	401/4073	51,008	1,904,385
29	OPUC Order #10-064 (182339)					
30	(Avg amort 35yrs for each yr capitalized expense)					
31						
32	Deferred Pension Expense Net of Contributions	17,140,322	38,341,161	Various	42,641,622	12,839,861
33	IPUC Order #30333 (182321)					
34						
35	AOCI Impact of Unfunded Pension Liability	246,966,765	60,448,165	228	14,460,369	292,954,561
36	IPUC Order #30256 (182320)					
37						
38	ID DSM Rider Reclass IPUC Order #29026 (182301)	5,321,997	2,803,416	254	8,125,413	
39						
40	PCAM Oregon 2008 (182346)	6,454,985	522,415			6,977,400
41	OPUC Order #08-238					
42						
43	PCAM Interest Reserve 2008 (182329)	(429,062)		4210	171,220	-600,282

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

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	OPUC Order #08-238					
2						
3	Excess Power Cost Deferral 2007 (182358)	4,762,316	2,178,235	254	4,537,039	2,403,512
4	IPUC Order #09-189					
5						
6	2007 EPC Interest Reserve (182351)	(308,869)	149,208			-159,661
7	IPUC Order #09-189					
8						
9	Oregon DSM Rider Reclass (182359)	3,537,442	11,370,116	254	14,907,558	
10	OPUC Advice #05-03					
11						
12	2009 Reorg IPUC Order #330914 (182318)	691,967		401	230,656	461,311
13	(amort period 01/10 thru 12/14)					
14						
15	OATT Revenue Deferred Reserve (182336)	2,064,469		400	401,425	1,663,044
16	IPUC Order #30940 (amort period 01/11 thru 12/13)					
17						
18	Idaho Pension Cash (182327)	38,976,484	48,631,908	401/4210	37,572,305	50,036,087
19	IPUC Order #32248 (amort period 06/11 thru 05/14)					
20						
21	FERC Pension Cash (182328)	582,156	70,000	401	437,695	214,461
22	IPUC Order #32248 (amort period 06/11 thru 05/14)					
23						
24	Excess Power Cost Unbilled Amort (186356)	(142,646)	1,888,291	401	1,883,067	-137,422
25						
26	Cus Efficiency Incentive IPUC Order #32245 (182317)	7,230,724	6,889,623	254	34,146	14,086,201
27						
28	Cus Efficiency Incen Res IPUC Order #32245 (182314)	(134,282)	291,455	1823/4210	1,073,638	-916,465
29						
30	Lidar Surveys IPUC Order #32426 (182361)	436,047		402	43,605	392,442
31	(amort period 01/12 thru 12/21)					
32						
33	Bennett Mtn Maintenance IPUC Order #32426	299,546		402	74,886	224,660
34	(amort period 01/12 thru 12/15) (182379)					
35						
36	PCA Unbilled Amortization (182316)		27,899,136	254/401	25,207,858	2,691,278
37						
38	Idaho Boardlman ARO Order #32549 (182393)		1,476,390	4031/4110	100,337	1,376,053
39						
40	Langley Revenue Accrual Order #12-226 (182398)		814,665	4074	7,271	807,394
41						
42	Minor items (28)	257,332	1,926,126	Various	1,946,764	236,694
43						
44	**TOTAL :**	989,194,015	596,482,397		444,565,686	1,141,110,726

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

Accounts included in minor items:
182305
182331
182334
182335
182340
182344
182345
182349
182350
182352
182353
182355
182362
182369
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182397
182399

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

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Prepaid ROW (186160)	715,957	113,600	401	91,362	738,195
2	Rents/Easements Long Term					
3						
4	Advance Prepaid (186709)	1,367,261		143/151	33,315	1,333,946
5	Coal Royalties					
6						
7	Security plan (186720)	19,001,732	881,380	165/4262	1,386,445	18,496,667
8	Net Insurance Asset					
9						
10	American Falls Bond Ref(186722)	191,604		401	14,552	177,052
11	(Amort 04/00 - 02/25)					
12						
13	Prepaid Credit Facility(186025)	992,670	1,445,227	431	1,475,836	962,061
14	(amort period 10/12 thru 10/17)					
15						
16	Company Owned (186726)	5,058,356	1,982,401	Various	2,891,345	4,149,412
17	Life Insurance					
18						
19	American Falls Water Rights	13,632,948		401	1,042,009	12,590,939
20	(amort 01/06 - 02/25) (186727)					
21						
22	Milner Bond Guarantee (186734)	6,381,818		253	1,063,636	5,318,182
23	(Amort 02/07 - 2/17)					
24						
25	American Falls - Bond refinance	631,989		401	47,999	583,990
26	(Amort through 02/25)(186770)					
27						
28	Transmission Deposit(186784)	710,578	6,987	131	717,565	
29						
30	Prepaid Exp (186052)	650,472	1,163,703	401	665,987	1,148,188
31	Contract I.T. Long Term					
32						
33	Long Term (186121)	1,268,456		228	53,791	1,214,665
34	Workers Compensation					
35						
36	Power Plant- Valmy (186793)	136,406	683,486	107	803,397	16,495
37						
38	Power Plant- Boardman (186794)	104,813	61,020	107/401	164,234	1,599
39						
40	Transmission & Generation		6,651,247	Various	5,429,021	1,222,226
41	Studies (186623)					
42						
43	Prepaid Coal LT (186797)		5,958,328			5,958,328
44						
45	Minor Items & Job Orders (4)	35,142	8,175,376	Various	8,208,613	1,905
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	50,880,202				53,913,850

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

Accounts included in minor items:
186100
186304
186731
186946

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

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5	Other Electric (See footnote)	51,394,143	109,509,600
6			
7	Other (See footnote)	157,500,863	185,672,424
8	TOTAL Electric (Enter Total of lines 2 thru 7)	208,895,006	295,182,024
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric See footnote	19,082,040	21,080,753
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	227,977,046	316,262,777

Notes

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

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

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

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

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

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

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

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
13				
14				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2013	End of 2012/Q4

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		
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39		
40	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

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

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

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

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.25%Series due 2013	70,000,000	641,201
19			372,696 D
20			
21	4.75% Series due 2012	100,000,000	944,356
22			1,047,617 D
23			
24	6.00% Series due 2032	100,000,000	1,191,216
25			543,244 D
26			
27	5.875% Series due 2034	55,000,000	-585,759
28			746,961 D
29			
30	5.50% Series due 2034	50,000,000	524,419
31			383,322 D
32			
33	TOTAL	1,647,045,000	27,957,280

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

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	4.85% Series Due 2040	100,000,000	1,284,871
2			169,984 D
3			
4	6.30% Series due 2037	140,000,000	1,495,799
5			278,367 D
6			
7	6.25% Series due 2037	100,000,000	1,141,489
8			267,677 D
9			
10	Port of Morrow Variable due 2027	4,360,000	188,545
11			
12	Humboldt Variable due 2024	49,800,000	1,697,856
13			
14	Sweetwater Variable due 2026	116,300,000	3,026,122
15			
16			
17	6.025 % Series Due 2018	120,000,000	1,630,120
18			
19	4.30% Series Due 2042	75,000,000	802,240
20			49,417 D
21	2.95% Series Due 2022	75,000,000	708,490
22			127,607 D
23	Subtotal Account 221	1,615,460,000	27,957,280
24			
25	Account 222 - Reaquired Bonds		
26			
27	Account 223: Advances for Associated Companies		
28			
29	Account 224:		
30	Bond Guarantee - American Falls	19,885,000	
31	Note Guarantee - Milner Dam	11,700,000	
32	Subtotal Account 224	31,585,000	
33	TOTAL	1,647,045,000	27,957,280

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

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	6,150,000	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	3,400,000	12
						13
						14
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	15
						16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12		1,781,250	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
						26
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	27
						28
						29
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	30
						31
						32
				1,540,663,182	78,922,057	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	1
						2
						3
6/22/07	6/15/2037	6/22/07	6/15/37	140,000,000	8,820,000	4
						5
						6
10/18/07	10/15/2037	10/18/07	10/15/37	100,000,000	6,250,000	7
						8
						9
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	37,232	10
						11
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	12
						13
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	14
						15
						16
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	17
						18
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	2,311,250	19
						20
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	1,585,625	21
						22
				1,515,460,000	78,922,057	23
						24
						25
						26
						27
						28
						29
04/26/00	2/1/25			19,885,000		30
02/10/92				5,318,182		31
				25,203,182		32
				1,540,663,182	78,922,057	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	168,168,039
2		
3		
4	Taxable Income Not Reported on Books	
5		146,862,154
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-11,311,953
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		48,548,226
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		255,170,014
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	
30		
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44		

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

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

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

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

FOOTNOTE DATA

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

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

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

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

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

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

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

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

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

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
10,546		-14,482,226			-102,583	2
-8		13,701,846				3
		93,541				4
10,538		-686,839			-102,583	5
						6
						7
9,450,196		20,314,893			589,202	8
11,534	850				23,078	9
-2,489,982		1,150,954			-336,605	10
91,860		1,909,280				11
1		681,157				12
		2,042,319				13
		150				14
7,063,609	850	26,098,753			275,675	15
						16
						17
	1,341,027	2,407,945			117,447	18
					1,562	19
-125,615		-104,242			-10,241	20
		162,571				21
		45,074				22
193,128		748,331				23
67,513	1,341,027	3,259,679			108,768	24
						25
						26
135,376		270,367			575	27
135,376		270,367			575	28
						29
						30
	466,735	985,247				31
	466,735	985,247				32
						33
						34
		4,850				35
821,427		1,642,855				36
821,427		1,647,705				37
11,324		-39,099			-3,024	38
		-14,521,618				39
						40
8,109,787	1,808,612	17,014,195			279,411	41

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

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

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

```
Account 107        $ 587,202
```

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

```
Account 408.2      $ 23,078
```

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

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

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

The $2,000 was for irrigation customer refunds. The refunds had a contra balances and were inadverently reclassed from account 236208 to 143900.

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

```
Account 107        $ 117,447
```

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

```
Account 408.2      $   1,562
```

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

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

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

```
Account 131        $    575
```

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

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

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

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

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	665,312				63,866	
4	7%						
5	10%	23,955,140				1,491,712	
6	11%	1,240,255				26,372	
7	Other - State	44,979,694	411.4	12,322,953	411.4	1,684,801	
8	TOTAL	70,840,401		12,322,953		3,266,751	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	44,979,695	411.4	12,322,953	411.4	1,684,801	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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43							
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46							
47							
48							

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

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
601,446	10.42		3
			4
22,463,428	16.06		5
1,213,883	47.03		6
55,617,846	26.70		7
79,896,603			8
			9
			10
			11
55,617,847			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
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			44
			45
			46
			47
			48

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

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Smart Grid (253200)	12,764,219	107/401	294,038,860	285,919,580	4,644,939
2						
3	Point to Point Trans Study(253201)	876,153	232	500		875,653
4						
5	FTV (253202)	4,066,666	400	400,000		3,666,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Boardman To Hemingway (253220)		143/107	11,951,306	12,803,157	851,851
9						
10	Sho Ban Trans ROW (253480)	247,500	242	15,000		232,500
11	(Amort Period Jan 2005-Dec 2027)					
12						
13	Milner Falling Water (253953)	1,098,421	186/401	1,063,636	824,695	859,480
14	Amort Period (Feb 1992 - Feb 2017)					
15						
16	Postretirement Benefits (253960)	2,998,707	401	893,956		2,104,751
17						
18	Directors Deferred Compensation	4,638,308	131	505,560	524,626	4,657,374
19	(253980-253999)					
20						
21	IBM Mainframe Software Licenses	734,853	232	775,115	40,262	
22	(Amort period 2010-2015) (253950)					
23						
24	USAF Battery Replacement (253906)	105,706	107	137,263	31,575	18
25						
26	Minor Items (2)	39	various	22	89,623	89,640
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	27,530,572		309,781,218	300,233,518	17,982,872

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

Accounts included in minor items:
253000
253042

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

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (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	333,334,634	82,177,337	9,229,112
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	333,334,634	82,177,337	9,229,112
6	Non-Operating Property			
7	Other - Regulatory Asset for I	599,991,590		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	933,326,224	82,177,337	9,229,112
10	Classification of TOTAL			
11	Federal Income Tax	795,963,655	81,445,627	9,160,530
12	State Income Tax	137,362,569	731,710	68,582
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						406,282,859	2
							3
							4
						406,282,859	5
							6
		182	18,328	182	74,023,292	673,996,554	7
							8
			18,328		74,023,292	1,080,279,413	9
							10
			15,376		59,850,992	928,084,368	11
			2,952		14,172,300	152,195,045	12
							13

NOTES (Continued)

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

FOOTNOTE DATA

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

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

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

ACCUMULATED 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	32,722,054	111,408,529	87,144,355
4				
5				
6				
7				
8	Other -- See Note	104,275,112		
9	TOTAL Electric (Total of lines 3 thru 8)	136,997,166	111,408,529	87,144,355
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	441,529		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	137,438,695	111,408,529	87,144,355
20	Classification of TOTAL			
21	Federal Income Tax	115,291,045	93,455,498	73,101,397
22	State Income Tax	22,147,650	17,953,031	14,042,958
23	Local Income Tax			

NOTES

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

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

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

NOTES (Continued)

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	3,394,965	175	13,988,797	14,888,370	4,294,538
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	359,418	175	1,263,773	1,189,137	284,782
5	IPUC Order # 28661					
6						
7	OER 32368-323697 - (254007)				581,743	581,743
8	Order # 32368					
9						
10	Unfunded Accum Def Income Tax (254966)	45,472,547	various	530,982	6,344,170	51,285,735
11						
12	Idaho DSM Rider (254201)		various	34,245,702	38,286,324	4,040,622
13	Order #29026					
14						
15	Oregon DSM Rider - (254202)		various	16,626,489	12,711,554	-3,914,935
16	Advise #05-03					
17						
18	Oregon Solar Pilot - (254005)	766,096	various	233,363	659,888	1,192,621
19	Order #10-198					
20						
21	Oregon Reclass (254204)	4,110,320	1823	5,580,001	1,469,681	
22						
23	Green Tags Oregon (254415)	279,605	various	286,696	161,484	154,393
24	Order #11-086					
25						
26	Power Cost Adjustment-Current (254423)	10,578,946	1823	63,448,231	52,869,285	
27						
28	Regulatory Unfunded Accum Def Income Tax (254419)	3,780,588	1823	60,778	79,106	3,798,916
29						
30	Revenue Sharing (254101)	27,098,897	various	27,200,636	7,252,960	7,151,221
31	IPUC Order #32558					
32						
33	BPA Credit Residential Idaho (254401)	411,557	various	1,534,209	1,672,522	549,870
34	Advice # 11-03 (ID) #11-15 (OR)					
35						
36	WAQC Carryover (254901)	159,309	various	159,309	87,634	87,634
37	IPUC Order #29505					
38						
39						
40						
41	TOTAL	96,483,245		166,095,646	139,014,187	69,401,786

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

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Idaho Boardman Decommissing - (254393)		143/400	444,146	152,957	-291,189
2	IPUC Order #32549					
3						
4	Oregon Boardman Decommissing - (254394)		143/400	144,780	49,395	-95,385
5	OPUC Order #12235					
6						
7	Bridger Depreciation #12-296 -(254800)				168,224	168,224
8						
9						
10	Minor Items (8)	70,997	various	347,754	389,753	112,996
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	96,483,245		166,095,646	139,014,187	69,401,786

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

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

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

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	431,555,478	405,981,556
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	375,354,223	322,307,065
5	Large (or Ind.) (See Instr. 4)	145,054,266	140,701,371
6	(444) Public Street and Highway Lighting	3,588,495	3,289,385
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	955,552,462	872,279,377
11	(447) Sales for Resale	61,534,224	101,602,140
12	TOTAL Sales of Electricity	1,017,086,686	973,881,517
13	(Less) (449.1) Provision for Rate Refunds	17,809,784	37,734,709
14	TOTAL Revenues Net of Prov. for Refunds	999,276,902	936,146,808
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,645,018	3,564,200
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,226,450	24,256,300
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	27,882,803	38,244,930
22	(456.1) Revenues from Transmission of Electricity of Others	21,054,698	19,372,904
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	75,808,969	85,438,334
27	TOTAL Electric Operating Revenues	1,075,085,871	1,021,585,142

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

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,039,358	5,146,013	413,610	409,786	2
				3
5,881,587	5,458,954	82,485	82,045	4
3,132,573	3,099,743	118	123	5
31,798	29,720	2,069	1,578	6
				7
				8
				9
14,085,316	13,734,430	498,282	493,532	10
2,183,262	3,634,924			11
16,268,578	17,369,354	498,282	493,532	12
				13
16,268,578	17,369,354	498,282	493,532	14

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

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

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

This consists of :

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

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

This consists of :

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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,036,448	421,030,853	412,920	12,197	0.0836
3	03 - Residential Master Meter	4,493	354,253	23	195,348	0.0788
4	04 - Residential - EW		-15			
5	05 - Residential - TOD	8,553	710,075	667	12,823	0.0830
6	15 - Dusk to dawn lighting	2,807	618,102			0.2202
7	Unbilled Revenues	-12,992	1,986,871			-0.1529
8	Other Revenues		6,855,335			
9	Total 440	5,039,309	431,555,474	413,610	12,184	0.0856
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	158,687	16,695,877	30,745	5,161	0.1052
13	09P - General service	455,960	23,295,097	194	2,350,309	0.0511
14	09S - General service	3,202,887	192,136,834	31,743	100,901	0.0600
15	09T - General service	5,025	273,445	3	1,675,000	0.0544
16	15 - Dusk to Dawn Light	4,092	678,277			0.1658
17	19P - Uniform rate contracts	2,157,337	96,558,875	110	19,612,155	0.0448
18	19S - Uniform rate contracts	6,493	325,376	1	6,493,000	0.0501
19	19T - Uniform rate contracts	107,954	5,260,412	4	26,988,500	0.0487
20	24 - Irrigation Pumping	2,048,435	134,326,911	18,955	108,068	0.0656
21	40 - General service	11,188	804,135	845	13,240	0.0719
22	Special Contracts	862,444	39,505,500	4	215,611,000	0.0458
23	Commercial & Industrial Unbill	-6,293	2,111,315			-0.3355
24	Other Revenues		8,436,439			
25	Total 442	9,014,209	520,408,493	82,604	109,126	0.0577
26						
27	444 - Public Street Lighting:					
28	40 - General service	1,167	83,845	444	2,628	0.0718
29	41 - Street lighting	27,477	3,257,727	1,208	22,746	0.1186
30	42 - Traffic control lighting	2,831	141,880	417	6,789	0.0501
31	Unbilled	323	37,986			0.1176
32	Other Revenues		67,057			
33	Total 444	31,798	3,588,495	2,069	15,369	0.1129
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,104,278	951,416,290	498,283	28,306	0.0675
42	Total Unbilled Rev.(See Instr. 6)	-18,962	4,136,172	0	0	-0.2181
43	TOTAL	14,085,316	955,552,462	498,283	28,268	0.0678

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

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

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

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

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

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

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

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

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

SALES FOR RESALE (Account 447)

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

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
2	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
3	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
4	Citigroup Energy Inc.	OS	WSPP	n/a	n/a	n/a
5	Citigroup Energy Inc.	OS	-	n/a	n/a	n/a
6	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
7	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
8	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
9	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
10	Grant CO Public Utility District #2 --	SF	WSPP	n/a	n/a	n/a
11	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
12	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
13	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
14	J.P. Morgan Ventures Energy Corporation	OS	-	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
2	J.P. Morgan Chase Bank, N.A.	OS	WSPP	n/a	n/a	n/a
3	Jeffries Bache	OS	-	n/a	n/a	n/a
4	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
5	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
6	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
7	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
8	NextEra Energy Power Marketing, LLC	SF	WSPP	n/a	n/a	n/a
9	Noble Americas Gas & Power corp.	SF	WSPP	n/a	n/a	n/a
10	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
11	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
12	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
13	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
14	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (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	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
2	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
3	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
4	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
5	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
6	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
7	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
8	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
9	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
10	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
11	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
12	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
13	Royal Bank of Canada	OS	-	n/a	n/a	n/a
14	Seattle City Light	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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	Seattle City Light	SF	WSPP	n/a	n/a	n/a
2	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
3	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
4	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
5	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
6	Sierra Pacific Power Co., dba NV Energy	SF	T-7	n/a	n/a	n/a
7	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
8	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
9	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
10	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
11	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
12	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
13	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
14	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
2	United Materials of Great Falls	LF	61	n/a	n/a	n/a
3	Prior Year Adjustments	AD	-	n/a	n/a	n/a
4	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

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

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

SALES FOR RESALE (Account 447) (Continued)

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

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

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.
			187	187	1
500		8,450		8,450	2
10,200		227,585		227,585	3
68,282		716,707		716,707	4
27,580		309,325		309,325	5
			5,383	5,383	6
1,113		8,860		8,860	7
4,316		80,444		80,444	8
5,937		101,787		101,787	9
4,145		53,390		53,390	10
			65,710	65,710	11
166,796		3,512,095		3,512,095	12
		749,628		749,628	13
525		11,075		11,075	14
0	0	0	0	0	
2,183,262	0	60,673,995	860,229	61,534,224	
2,183,262	**0**	**60,673,995**	**860,229**	**61,534,224**	

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

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

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

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

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Schedule Page: 310.3 Line No.: 13 Column: b
ISDA Master Agreement with Royal Bank of Canada dated August 26, 2005

Schedule Page: 310.3 Line No.: 14 Column: b
Non-Firm Sales

Schedule Page: 310.4 Line No.: 2 Column: b
ISDA Master Agreement with Shell Energy North America dated November 1, 2009

Schedule Page: 310.4 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 4 Column: b
Non-Firm Sales

Schedule Page: 310.4 Line No.: 6 Column: b
Spinning or Operating Reserves

Schedule Page: 310.4 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 9 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 13 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 14 Column: b
Non-Firm Sales

Schedule Page: 310.5 Line No.: 2 Column: a
Contract expiration date 05/31/2013

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,402,743	1,690,161
5	(501) Fuel	134,501,103	119,844,954
6	(502) Steam Expenses	8,279,623	6,950,410
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,539,354	2,231,309
10	(506) Miscellaneous Steam Power Expenses	8,331,843	9,734,263
11	(507) Rents	285,311	498,085
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	154,339,977	140,949,182
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	331,355	2,075,559
16	(511) Maintenance of Structures	759,002	920,609
17	(512) Maintenance of Boiler Plant	12,605,603	15,351,039
18	(513) Maintenance of Electric Plant	5,139,307	6,827,635
19	(514) Maintenance of Miscellaneous Steam Plant	4,996,617	6,486,063
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,831,884	31,660,905
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	178,171,861	172,610,087
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,437,986	5,380,371
45	(536) Water for Power	7,810,554	8,772,110
46	(537) Hydraulic Expenses	12,715,046	12,513,192
47	(538) Electric Expenses	1,376,025	1,611,582
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,634,251	3,081,121
49	(540) Rents	329,209	209,213
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	32,303,071	31,567,589
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	305,070	1,763,673
54	(542) Maintenance of Structures	1,329,157	1,722,862
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,343,402	1,563,284
56	(544) Maintenance of Electric Plant	3,114,538	1,789,947
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,071,383	2,719,281
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,163,550	9,559,047
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,466,621	41,126,636

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,342,636	820,192
63	(547) Fuel	24,912,210	11,696,917
64	(548) Generation Expenses	2,167,816	749,804
65	(549) Miscellaneous Other Power Generation Expenses	403,386	779,335
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	28,826,048	14,046,248
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	208,028	179,520
71	(553) Maintenance of Generating and Electric Plant	99,722	115,128
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,537,689	1,861,365
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,845,439	2,156,013
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	31,671,487	16,202,261
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	190,640,708	156,873,749
77	(556) System Control and Load Dispatching	2,250	1,219
78	(557) Other Expenses	-57,611,492	41,459,600
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	133,031,466	198,334,568
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	384,341,435	428,273,552
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,580,561	3,326,891
84			192,086
85	(561.1) Load Dispatch-Reliability	130,631	192,086
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,170,321	1,188,357
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,345,152	1,423,636
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	97,740	102,697
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,359,494	2,252,352
94	(563) Overhead Lines Expenses	659,259	746,070
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,294,410	6,462,104
97	(566) Miscellaneous Transmission Expenses	175,701	307,899
98	(567) Rents	3,002,229	3,283,621
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,815,498	19,285,713
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	484,817	220,612
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	13,444	54,018
104	(569.2) Maintenance of Computer Software	749,101	347,776
105	(569.3) Maintenance of Communication Equipment	4,138	26,183
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,689,469	2,975,539
108	(571) Maintenance of Overhead Lines	5,293,220	3,675,361
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,530	5,474
111	TOTAL Maintenance (Total of lines 101 thru 110)	10,235,719	7,304,963
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	29,051,217	26,590,676

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,118,843	3,746,431
135	(581) Load Dispatching	3,549,914	3,482,055
136	(582) Station Expenses	1,157,508	1,192,869
137	(583) Overhead Line Expenses	3,786,758	3,039,224
138	(584) Underground Line Expenses	1,870,345	1,825,857
139	(585) Street Lighting and Signal System Expenses	109,636	122,065
140	(586) Meter Expenses	4,132,819	4,130,937
141	(587) Customer Installations Expenses	642,062	1,092,077
142	(588) Miscellaneous Expenses	5,622,888	5,494,553
143	(589) Rents	493,172	830,940
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,483,945	24,957,008
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	224,177	402,381
147	(591) Maintenance of Structures		5,711
148	(592) Maintenance of Station Equipment	3,819,880	3,230,860
149	(593) Maintenance of Overhead Lines	15,554,326	14,495,482
150	(594) Maintenance of Underground Lines	1,046,527	1,054,033
151	(595) Maintenance of Line Transformers	422,582	433,841
152	(596) Maintenance of Street Lighting and Signal Systems	568,715	554,042
153	(597) Maintenance of Meters	725,957	472,599
154	(598) Maintenance of Miscellaneous Distribution Plant	529,977	252,535
155	TOTAL Maintenance (Total of lines 146 thru 154)	22,892,141	20,901,484
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	48,376,086	45,858,492
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	441,306	427,283
160	(902) Meter Reading Expenses	1,379,745	2,453,647
161	(903) Customer Records and Collection Expenses	13,188,955	12,944,062
162	(904) Uncollectible Accounts	4,512,906	4,269,718
163	(905) Miscellaneous Customer Accounts Expenses	413	252
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	19,523,325	20,094,962

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	535,711	528,250
168	(908) Customer Assistance Expenses	33,737,489	44,034,548
169	(909) Informational and Instructional Expenses	295,583	82,775
170	(910) Miscellaneous Customer Service and Informational Expenses	554,027	531,823
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	35,122,810	45,177,396
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	70,376,748	67,143,039
182	(921) Office Supplies and Expenses	18,940,073	15,742,902
183	(Less) (922) Administrative Expenses Transferred-Credit	28,236,018	26,009,805
184	(923) Outside Services Employed	5,177,361	4,925,844
185	(924) Property Insurance	3,506,576	3,207,120
186	(925) Injuries and Damages	7,150,892	5,806,100
187	(926) Employee Pensions and Benefits	61,791,248	60,010,908
188	(927) Franchise Requirements	9	
189	(928) Regulatory Commission Expenses	5,692,486	3,449,337
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	493,057	552,129
192	(930.2) Miscellaneous General Expenses	4,026,891	3,750,121
193	(931) Rents	17,598	7,103
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,936,921	138,584,798
195	Maintenance		
196	(935) Maintenance of General Plant	5,160,763	4,522,111
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	154,097,684	143,106,909
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	670,512,557	709,101,987

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Cogeneration and Small Power Producers					
2	AgPower Jerome/Double A Digester	LU	-	.488		
3	Allan Ravenscroft/Malad River	LU	-	NA	NA	NA
4	Bennett Creek Wind Farm	LU	-	NA	NA	NA
5	Bettencourt DryCreek Biofactory	LU	-	NA	NA	NA
6	Big Sky West Dairy Digester	LU	-	NA	NA	NA
7	Big Wood Canal Company					
8	Black Canyon #3	LU	-	NA	NA	NA
9	Jim Knight	LU	-	NA	NA	NA
10	Sagebrush	LU	-	NA	NA	NA
11	Blind Canyon Hydro	LU	-	NA	NA	NA
12	Branchflower/Trout Company	LU	-	NA	NA	NA
13	Burley Butte Wind Park	LU	-	NA	NA	NA
14	Bypass Limited	LU	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(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)	Average Monthly CP Demand (f)
1	Camp Reed Wind Park	LU	-	NA	NA	NA
2	Cargill Inc./B6 Anaerobic Digester	LU	-	NA	NA	NA
3	Cassia Gulch Wind Park	LU	-	NA	NA	NA
4	Cassia Wind Farm	LU	-	NA	NA	NA
5	City of Cove, Oregon/Mill Creek	LU	-	NA	NA	NA
6	City of Hailey	LU	-	NA	NA	NA
7	City of Pocatello	LU	-	NA	NA	NA
8	Clear Springs Food Inc.	LU	-	NA	NA	NA
9	Clifton E. Jenson/Birchcreek	LU	-	.05		
10	Cold Springs Windfarm, LLC	LU	-	NA	NA	NA
11	Consolidated Hydro Inc./Enel					
12	Barber Dam	LU	-	NA	NA	NA
13	Dietrich Drop	LU		NA	NA	NA
14	GeoBon #2	LU	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(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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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		NA	NA	NA
2	Rock Creek #2	LU	-	NA	NA	NA
3	Contractors Power Group Inc./Mile 28	LU	-	NA	NA	NA
4	Crystal Springs Hydro	LU	-	NA	NA	NA
5	Curry Cattle Company	LU	-	NA		
6	David McCollum/Canyon Springs	LU	-	NA	NA	NA
7	David R Snedigar	LU	-	NA	NA	NA
8	Desert Meadow Wind Farm	LU	-	NA	NA	NA
9	Faulkner Brothers Hydro Inc.	LU	-	NA	NA	NA
10	Fisheries Development	OS	-	NA	NA	NA
11	Fossil Gulch Wind	LU	-	NA	NA	NA
12	G2 Energy Hidden Hollow	LU	-	NA	NA	NA
13	Glenns Ferry Cogen Partners/Magic	LU	-	NA	NA	NA
14	Golden Valley Wind Park	LU	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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	Hammett Hill Windfarm, LLC	LU		NA	NA	NA
2	Hazelton B Power Company	LU	-	NA	NA	NA
3	High Mesa Energy	LU		NA	NA	NA
4	H.K. Hydro Mud Creek S & S	LU	-	NA	NA	NA
5	Horeshoe Bend Hydro	LU	-	NA	NA	NA
6	Horseshoe Bend Wind/United Materials	LU	-	NA	NA	NA
7	Hot Springs Wind Farm	LU	-	NA	NA	NA
8	Idaho Winds/Sawtooth Wind Project	LU	-	NA	NA	NA
9	JR Simplot Co.	LU	-	NA	NA	NA
10	J.M. Miller/Sahko Hydro	LU	-	NA	NA	NA
11	James B. Howell/CHI Elk Creek	LU	-	NA	NA	NA
12	John R LeMoyne	LU	-	NA	NA	NA
13	Kasel & Witherspoon	LU	-	NA	NA	NA
14	Koyle Hydro Inc.	LU	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lateral 10 Ventures	LU	-	NA	NA	NA
2	Lemhi Hydro Power Co./Schaffner	LU	-	NA	NA	NA
3	Lime Wind	LU	-	NA	NA	NA
4	Little Mac Power Co./Cedar Draw	LU	-	NA	NA	NA
5	Little Wood River Irrigation District	LU	-	NA	NA	NA
6	Magic Reservoir Hydro	LU	-	NA	NA	NA
7	Mainline Windfarm	LU		NA	NA	NA
8	Marco Rancher's Irrigation Inc.	LU	-	NA	NA	NA
9	Marysville Hydro Partners/Falls River	LU	-	NA	NA	NA
10	Milner Dam Wind Park	LU	-	NA	NA	NA
11	Mud Creek White Hydro, Inc	LU	-	NA	NA	NA
12	New Energy One/Rock Creek Diary	LU		NA	NA	NA
13	Oregon Trail Wind Park	LU	-	NA	NA	NA
14	Owyhee Irrigation District					
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Mitchell Butte	LU	-	NA	NA	NA
2	Owyhee Dam	LU	-	NA	NA	NA
3	Tunnel #1	LU	-	NA	NA	NA
4	Paynes Ferry Wind Park	LU	-	NA	NA	NA
5	Pigeon Cove Power	LU		NA	NA	NA
6	Pilgrim Stage Station Wind Park	LU	-	NA	NA	NA
7	Pristine Springs Inc #1	LU	-	NA	NA	NA
8	Pristine Springs Inc #3	LU	-	NA	NA	NA
9	Reynolds Irrigation District	LU	-	NA	NA	NA
10	Richard Kaster					
11	Box Canyon	LU	-	NA	NA	NA
12	Briggs Creek	LU	-	NA	NA	NA
13	Rim View Trout Company	OS	-	NA	NA	NA
14	Riverside Hydro/Mora Drop	LU	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Riverside Investments/Arena Drop	LU	-	NA	NA	NA
2	Rock Creek #1 Joint Venture	LU		NA	NA	NA
3	Rockland Wind Project	LU	-	NA	NA	NA
4	Rupert Cogen Partners/Magic Valley	LU	-	NA	NA	NA
5	Ryegrass Windfarm	LU		NA	NA	NA
6	Salmon Falls Wind Park	LU	-	NA	NA	NA
7	SE Hazelton A LP	LU	-	NA	NA	NA
8	Shorock Hydro Inc.					NA
9	Shoshone Cspp	LU	-	NA	NA	NA
10	Shoshone #2	LU	-	NA	NA	NA
11	Snake Rivery Pottery	LU	-	NA	NA	NA
12	South Forks JointVenture/Lowline Canal	LU	-	NA	NA	NA
13	Tamarack Energy Partnership	LU		NA		
14	Tasco - Nampa	OS	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Other Purchased Power					
2	Arizona Public Service Co.	SF	WSPP	NA	NA	NA
3	Avista Corp.	SF	T-12	NA	NA	NA
4	Avista Corp.	SF	WSPP	NA	NA	NA
5	Avista Corp.	OS	WSPP	NA	NA	NA
6	Barclays Bank PLC	OS		NA	NA	NA
7	Black Hills Power Inc.	SF	WSPP	NA	NA	NA
8	Bonneville Power Administration	OS	WSPP	NA	NA	NA
9	Bonneville Power Administration	SF	WSPP	NA	NA	NA
10	BP Energy Company	SF	WSPP	NA	NA	NA
11	Brookfield Energy Marketing LP	SF	WSPP	NA	NA	NA
12	Calpine Energy Services, L.P.	SF	WSPP	NA	NA	NA
13	Cargill Power Markets LLC	OS	WSPP	NA	NA	NA
14	Cargill Power Markets LLC	SF	WSPP	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Chelan Co PUD	SF	WSPP	NA	NA	NA
2	Citigroup Energy Inc.	SF	WSPP	NA	NA	NA
3	Citigroup Energy Inc.	OS	-	NA	NA	NA
4	Clatskanie PUD	SF	WSPP	NA	NA	NA
5	Constellation Energy Commodities Group	SF	WSPP	NA	NA	NA
6	Constellation Energy Commodities Group	SF	WSPP	NA	NA	NA
7	DB Energy Trading LLC	SF	WSPP	NA	NA	NA
8	Douglas County PUD	SF	WSPP	NA	NA	NA
9	EDF Trading North America, LLC	SF	WSPP	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
11	Grant CO Public Utility District #2 --	SF	WSPP	NA	NA	NA
12	IBERDROLA RENEWABLES, Inc.	SF	WSPP	NA	NA	NA
13	J.P. Morgan Ventures Energy Corporatio	OS		NA	NA	NA
14	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	JPMorgan Chase Bank, N.A.	OS	-	NA	NA	NA
2	Jefferies Bache	OS	-	NA	NA	NA
3	Macquarie Cook Power Inc.	SF	WSPP	NA	NA	NA
4	Macquarie Cook Power Inc.	OS	-	NA	NA	NA
5	NaturEner USA, LLC	SF	WSPP	NA	NA	NA
6	Nevada Power Co, DBA NV Energy	SF	WSPP	NA	NA	NA
7	NextEra Energy Power Marketing, LLC	SF	WSPP	NA	NA	NA
8	Noble Americas Gas&Power Corp	SF	WSPP	NA	NA	NA
9	NorthWestern Energy	SF	T-7	NA	NA	NA
10	PacifiCorp Inc.	SF	T-13	NA	NA	NA
11	PacifiCorp Inc.	SF	WSPP	NA	NA	NA
12	PacifiCorp Inc.	OS	WSPP	NA	NA	NA
13	Portland General Electric Company	SF	T-14	NA	NA	NA
14	Portland General Electric Company	SF	WSPP	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(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	Portland General Electric Company	SF	WSPP	NA	NA	NA
2	Powerex Corp.	SF	WSPP	NA	NA	NA
3	PPL EnergyPlus, LLC	SF	WSPP	NA	NA	NA
4	Public Service Company of New Mexico	SF	WSPP	NA	NA	NA
5	Puget Sound Energy, Inc.	SF	T-9	NA	NA	NA
6	Puget Sound Energy, Inc.	SF	WSPP	NA	NA	NA
7	Rainbow Energy Marketing Corporation	SF	WSPP	NA	NA	NA
8	Royal Bank of Canada	OS		NA	NA	NA
9	Salt River Project	SF	WSPP	NA	NA	NA
10	Seattle City Light	SF	WSPP	NA	NA	NA
11	Shell Energy North America (US), L.P.	SF	WSPP	NA	NA	NA
12	Shell Energy North America (US), L.P.	OS	-	NA	NA	NA
13	Sierra Pacific Power Co., dba NV Energ	SF	T-55	NA	NA	NA
14	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	NA	NA	NA
2	Snohomish County PUD	SF	WSPP	NA	NA	NA
3	Tacoma Power	SF	WSPP	NA	NA	NA
4	Tenaska Power Services Co.	SF	WSPP	NA	NA	NA
5	The Energy Authority, Inc.	SF	WSPP	NA	NA	NA
6	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	NA	NA	NA
7	Western Area Power Administration	SF	WSPP	NA	NA	NA
8	Raft River Energy I LLC	LU	-	NA	NA	NA
9	Telocaset Wind Power Partners LLC	LU	APP-A	NA	NA	NA
10	Neal Hot Springs Unit #1	LU		NA	NA	NA
11	Net Metering Customers	OS	-	NA	NA	NA
12	Oregon Solar Customers	OS	-	NA	NA	NA
13	Power Exchanges					
14	Bonneville Power Administration	EX	-	NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EDF Trading North America, LLC	EX		NA	NA	NA
2	NorthWestern Energy	EX	-	NA	NA	NA
3	PacifiCorp Inc.	EX	-	NA	NA	NA
4	Puget Sound Energy, Inc.	EX	-	NA	NA	NA
5	Powerex Corp.	EX		NA	NA	NA
6	Sierra Pacific Power Co., dba NV Energ	EX	-	NA	NA	NA
7	Utah Associated Municipal Power System	EX	-	NA	NA	NA
8	Clatskanie PUD	EX	153	NA	NA	NA
9	Sierra Pacific Power Co., dba NV Energ	EX	WSPP	NA	NA	NA
10	Other Transactions					
11	Acct Valuation-Clatskanie PUD Exchange		-			
12	Langley Test Power Valuation	OS	-	NA	NA	NA
13	Liquidated Damages-Yellowstone Power	OS		NA	NA	NA
14	Demand Response Avoided Energy	OS		NA	NA	NA
	Total					

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Boardman Assured Delivery	OS		NA	NA	NA
2	Write-Off	AD		NA	NA	NA
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

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

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
64,726				5,424,211		5,424,211	1
9,143				672,982		672,982	2
							3
23,923				1,175,521		1,175,521	4
2,998				209,635		209,635	5
80				5,415		5,415	6
1,467				106,811		106,811	7
3,513				296,133		296,133	8
351			17,500	9,944		27,444	9
12,439				346,402		346,402	10
							11
14,698				698,483		698,483	12
15,385				825,499		825,499	13
4,179				300,983		300,983	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,576				440,062		440,062	1
6,673				330,044		330,044	2
4,936				333,110		333,110	3
11,044				725,126		725,126	4
689			26,796	19,481		46,277	5
864				8,441		8,441	6
1,514				102,934		102,934	7
16,461				433,134		433,134	8
3,789				287,733		287,733	9
1,099				11,102		11,102	10
23,731				1,284,648		1,284,648	11
21,720				1,286,024		1,286,024	12
-166				-7,850		-7,850	13
34,438				1,580,265		1,580,265	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
16,448				414,328		414,328	1
23,796				1,621,877		1,621,877	2
2,953				54,023		54,023	3
1,440				104,264		104,264	4
49,527				3,362,216		3,362,216	5
18,435				933,389		933,389	6
46,107				2,663,754		2,663,754	7
60,426				4,423,976		4,423,976	8
71,483				4,222,561		4,222,561	9
1,215				76,458		76,458	10
4,571				313,446		313,446	11
648				35,806		35,806	12
3,361				257,792		257,792	13
3,650				297,697		297,697	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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.
5,627				352,786		352,786	1
1,329				98,009		98,009	2
5,932				418,425		418,425	3
5,810				365,660		365,660	4
6,785				466,142		466,142	5
28,950				1,408,094		1,408,094	6
19,037				505,255		505,255	7
2,864				192,451		192,451	8
57,156				3,606,451		3,606,451	9
54,588				2,621,322		2,621,322	10
456				30,464		30,464	11
3,793				183,609		183,609	12
36,596				1,793,891		1,793,891	13
							14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
4,921				115,851		115,851	1
19,479				368,154		368,154	2
15,103				1,587,748		1,587,748	3
61,858				5,187,761		5,187,761	4
8,640			486,150	212,535		698,685	5
32,486				1,560,718		1,560,718	6
864				49,425		49,425	7
1,258				67,177		67,177	8
896				64,112		64,112	9
							10
1,928				126,660		126,660	11
3,741				250,429		250,429	12
966				6,811		6,811	13
5,043				285,464		285,464	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
1,635				121,273		121,273	1
9,948			552,508	281,419		833,927	2
249,799				14,364,815		14,364,815	3
77,014				4,921,093		4,921,093	4
13,176				344,581		344,581	5
62,085				3,154,626		3,154,626	6
24,716				1,572,582		1,572,582	7
							8
2,114				167,389		167,389	9
2,601				171,417		171,417	10
380				25,525		25,525	11
27,963				1,974,673		1,974,673	12
35,686			1,576,498	1,342,975		2,919,473	13
477				3,830		3,830	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

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

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
12,347				307,211		307,211	2
51				1,127		1,127	3
129,077				2,135,092		2,135,092	4
					221,285	221,285	5
					569,254	569,254	6
1,700				43,600		43,600	7
					284,953	284,953	8
93,776				1,852,172		1,852,172	9
54,800				578,296		578,296	10
775				12,361		12,361	11
8,800				130,092		130,092	12
					245,194	245,194	13
102,396				1,409,954		1,409,954	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,034				121,705		121,705	1
91,625				2,281,427		2,281,427	2
					1,551,477	1,551,477	3
804				11,500		11,500	4
3				94		94	5
8,079				242,456		242,456	6
28,575				99,479		99,479	7
2,004				23,206		23,206	8
123,225				2,955,700		2,955,700	9
23,904				351,504		351,504	10
422				9,136		9,136	11
115,728				1,741,871		1,741,871	12
					112,088	112,088	13
58,800				1,170,570		1,170,570	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					416,376	416,376	1
					2,250,030	2,250,030	2
18,825				156,461		156,461	3
					1,110,405	1,110,405	4
2				88		88	5
375				12,925		12,925	6
5,947				69,770		69,770	7
400				12,200		12,200	8
46				1,013		1,013	9
363				6,782		6,782	10
5,300				142,900		142,900	11
					104,495	104,495	12
45				1,298		1,298	13
25,464				320,478		320,478	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
75				900		900	1
27,556				871,453		871,453	2
174,037				6,390,738		6,390,738	3
2,925				106,475		106,475	4
57				1,364		1,364	5
25,775				552,221		552,221	6
15,063				417,754		417,754	7
					-203,658	-203,658	8
900				39,500		39,500	9
23,670				475,718		475,718	10
47,463				717,312		717,312	11
					282,420	282,420	12
63				1,314		1,314	13
28,418				739,123		739,123	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					790	790	1
1,730				22,420		22,420	2
482				7,608		7,608	3
429				6,738		6,738	4
6,495				69,458		69,458	5
15,836				272,363		272,363	6
1				71		71	7
74,625				4,549,186		4,549,186	8
314,145				17,153,270		17,153,270	9
23,692				2,262,881		2,262,881	10
811				61,649		61,649	11
314				7,954		7,954	12
							13
	61,650						14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	92						1
		6,119					2
	170,446	257,349					3
	8						4
	29,370						5
		3,936					6
	262						7
	75,807	73,175					8
	54,678	54,678					9
							10
					-20,215	-20,215	11
				726,126		726,126	12
				-251,435		-251,435	13
				14,479,447		14,479,447	14
3,667,462	392,313	395,257	2,815,124	180,900,690	6,924,894	190,640,708	

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

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

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

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

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

Schedule Page: 326 Line No.: 2 Column: f
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Schedule Page: 326.1 Line No.: 9 Column: e
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Schedule Page: 326.1 Line No.: 9 Column: f
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Schedule Page: 326.2 Line No.: 5 Column: e
Unavailable

Schedule Page: 326.2 Line No.: 5 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 10 Column: b
Non Firm Purchases

Schedule Page: 326.3 Line No.: 2 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 9 Column: a
Ida West, a subsidiary of IDACORP, has partial ownership of these projects.

Schedule Page: 326.5 Line No.: 5 Column: e
Unavailable

Schedule Page: 326.5 Line No.: 5 Column: f
Unavailable

Schedule Page: 326.5 Line No.: 13 Column: b
Non Firm Purchases

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

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

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

Schedule Page: 326.6 Line No.: 13 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Co. The actual demand is not used in determining the cost of energy.

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

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

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

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

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

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

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

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

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

Schedule Page: 326.8 Line No.: 8 Column: b

Financial Transmission Losses

Schedule Page: 326.8 Line No.: 13 Column: b

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

Schedule Page: 326.9 Line No.: 3 Column: b

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

Schedule Page: 326.9 Line No.: 5 Column: b

Non Firm Purchases

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

ISDA Master Agreement with JP Morgan Ventures Energy Corporation dated May 1, 2011

Schedule Page: 326.10 Line No.: 1 Column: b

ISDA Master Agreement with JP Morgan Chase Bank dated November 4, 2005

Schedule Page: 326.10 Line No.: 2 Column: b

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

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

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

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

Financial Transmission Losses

Schedule Page: 326.11 Line No.: 1 Column: b

Non Firm Purchases

Schedule Page: 326.11 Line No.: 8 Column: b

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

Schedule Page: 326.11 Line No.: 12 Column: b

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

Schedule Page: 326.12 Line No.: 1 Column: b

Financial Transmission Losses

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

Unavailable

Schedule Page: 326.12 Line No.: 11 Column: b

Schedule 84 Net Metering

Schedule Page: 326.12 Line No.: 12 Column: b

Schedule 88 Oregon Solar

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

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 1 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 2 Column: b

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 5 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 6 Column: b

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
4	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
5	Cargill	Seattle City Light	Bonneville Power Administration	OS
6	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
7	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
8	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
11	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
12	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
13	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
14	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
16	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
17	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
19	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
21	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
24	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
25	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	SFP
26	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
28	BC Hydro Powerex	PacifiCorp East	Idaho Power Company	NF
29	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
31	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
32	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
33	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	SFP
34	BC Hydro Powerex	PacifiCorp West	PacifiCorp East	NF
	TOTAL			

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

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

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

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

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

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

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

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

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

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

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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(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	Sierra Pacific Power	PacifiCorp East	SFP
2	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
4	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	SFP
5	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	NF
6	Cargill-Alliant	Sierra Pacific Power	PacifiCorp West	SFP
7	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
8	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP
9	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	NF
10	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	SFP
11	Cargill-Alliant	Sierra Pacific Power	Bonneville Power Administration	LFP
12	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	NF
13	Cargill-Alliant	Sierra Pacific Power	Sierra Pacific Power	SFP
14	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
15	Cargill-Alliant	Sierra Pacific Power	PacifiCorp East	NF
16	Cargill-Alliant	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
17	Cargill-Alliant	Idaho Power Company	PacifiCorp East	NF
18	Cargill-Alliant	Idaho Power Company	NorthWestern/PacifiCorp East	NF
19	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	NF
20	Cargill-Alliant	Idaho Power Company	Sierra Pacific Power	SFP
21	Citigroup Energy			NF
22	Eagle Energy Partners	PacifiCorp West	PacifiCorp East	NF
23	Eagle Energy Partners	Bonneville Power Administration	PacifiCorp East	NF
24	Iberdrola Energy	PacifiCorp East	Idaho Power Company	NF
25	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
26	Iberdrola Energy	PacifiCorp East	Bonneville Power Administration	NF
27	Iberdrola Energy	PacifiCorp East	Sierra Pacific Power	NF
28	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
29	Iberdrola Energy	Idaho Power Company	PacifiCorp East	NF
30	Iberdrola Energy	Idaho Power Company	Sierra Pacific Power	NF
31	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
32	Iberdrola Energy	Bonneville Power Administration	PacifiCorp East	NF
33	Iberdrola Energy	Bonneville Power Administration	Sierra Pacific Power	NF
34	Iberdrola Energy	Avista	PacifiCorp East	NF
	TOTAL			

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(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.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	ENPR	BRDY		1,816	1,816	1
5	ENPR	LAGRANDE		229	229	2
5	ENPR	LOLO		76	76	3
5	ENPR	M345		2,622	2,622	4
5	GSHN	BPAT.NWMT		5	5	5
5	GSHN	HMWY		177	177	6
5	GSHN	LAGRANDE		1,741	1,741	7
5	GSHN	M345		45	45	8
5	HMWY	BORA		73,164	73,164	9
5	HMWY	BORA		2,163	2,163	10
5	HMWY	BRDY		3,772	3,772	11
5	HMWY	JBSN		218	218	12
5	HMWY	JEFF		724	724	13
5	HMWY	M345		5,414	5,414	14
5	JBSN	BORA		82	82	15
5	JBSN	BRDY		24	24	16
5	JBSN	ENPR		67	67	17
5	JBSN	HMWY		173	173	18
5	JBSN	LAGRANDE		842	842	19
5	JBSN	M345		14	14	20
5	JBWT	LAGRANDE		35	35	21
5	JEFF	BORA		3,845	3,845	22
5	JEFF	BORA		24	24	23
5	JEFF	BPAT.NWMT		37	37	24
5	JEFF	BRDY		9,819	9,819	25
5	JEFF	BRDY		272	272	26
5	JEFF	HMWY		351	351	27
5	JEFF	JBSN		45	45	28
5	JEFF	LAGRANDE		48	48	29
5	JEFF	M345		79	79	30
5	LAGRANDE	BORA		92,482	92,482	31
5	LAGRANDE	BORA		1,201	1,201	32
5	LAGRANDE	BRDY		54,739	54,739	33
5	LAGRANDE	BRDY		17,297	17,297	34
			0	**6,075,120**	**6,075,120**	

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	LAGRANDE	M345		9,467	9,467	1
5	LAGRANDE	M345		1,296	1,296	2
5	LOLO	BORA		8,133	8,133	3
5	LOLO	BORA		11,134	11,134	4
5	LOLO	BRDY		1,886	1,886	5
5	LOLO	BRDY		2,059	2,059	6
5	LOLO	M345		1,999	1,999	7
5	LOLO	M345		586	586	8
5	M345	BORA		155	155	9
5	M345	BPAT.NWMT		701	701	10
5	M345	BRDY		61	61	11
5	M345	LAGRANDE		1,067	1,067	12
5	BORA	LAGRANDE		306	306	13
5	BPAT.NWMT	BRDY		717	717	14
5	BPAT.NWMT	LAGRANDE		546	546	15
5	BRDY	LAGRANDE		717	717	16
5	ENPR	LAGRANDE		300	300	17
5	LAGRANDE	LAGRANDE		2,334	2,334	18
5	LAGRANDE	M345		8,144	8,144	19
5	LOLO	LAGRANDE		3,509	3,509	20
5	LOLO	LAGRANDE		720	720	21
5	LOLO	M345		1,756	1,756	22
5	LOLO	OTEC		1	1	23
5	AVAT.NWMT	M345		70	70	24
5	AVAT.NWMT	M345		72	72	25
5	BORA	AVAT.NWMT		459	459	26
5	BORA	BPAT.NWMT		150	150	27
5	BORA	BRDY		800	800	28
5	BORA	ENPR		3,884	3,884	29
5	BORA	LAGRANDE		1,776	1,776	30
5	BORA	M345		4,232	4,232	31
5	BORA	M345		1,448	1,448	32
5	BPAT.NWMT	BORA		1,468	1,468	33
5	BPAT.NWMT	BORA		8,827	8,827	34
			0	**6,075,120**	**6,075,120**	

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	BPAT.NWMT	BRDY		60	60	1
5	BPAT.NWMT	LAGRANDE		109	109	2
5	BPAT.NWMT	M345		8,109	8,109	3
5	BPAT.NWMT	M345		16,361	16,361	4
5	BRDY	AVAT.NWMT		200	200	5
5	BRDY	BORA		544	544	6
5	BRDY	BPAT.NWMT		25	25	7
5	BRDY	LAGRANDE		383	383	8
5	BRDY	M345		16,036	16,036	9
5	BRDY	M345		3,756	3,756	10
5	ENPR	BORA		55,633	55,633	11
5	ENPR	BORA		26,345	26,345	12
5	ENPR	M345		100	100	13
5	ENPR	M345		400	400	14
5	HCPR	BORA		1,096	1,096	15
5	HCPR	BORA		216	216	16
5	HCPR	M345		960	960	17
5	JBSN	M345		1,220	1,220	18
5	JBSN	M345		4,104	4,104	19
5	JEFF	BORA		107	107	20
5	JEFF	BRDY		671	671	21
5	JEFF	M345		10,766	10,766	22
5	LAGRANDE	BORA		7,587	7,587	23
5	LAGRANDE	BORA		1,021	1,021	24
5	LAGRANDE	BRDY		1,114	1,114	25
5	LAGRANDE	JBSN		10	10	26
5	LAGRANDE	M345		8,084	8,084	27
5	LAGRANDE	M345		736	736	28
5	LOLO	BORA		13,689	13,689	29
5	LOLO	BORA		11,490	11,490	30
5	LOLO	BRDY		1,542	1,542	31
5	LOLO	M345		52,221	52,221	32
5	LOLO	M345		16,981	16,981	33
5	LYPK	BORA		9,558	9,558	34
			0	**6,075,120**	**6,075,120**	

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

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

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

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

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5	LOLO	M345		145	145	1
5	M345	BORA		50	50	2
5	M345	LAGRANDE		842	842	3
5	AVAT.NWMT	BRDY		146	146	4
5	AVAT.NWMT	LAGRANDE		6	6	5
5	AVAT.NWMT	M345		236	236	6
5	BORA	BRDY		292	292	7
5	BORA	LAGRANDE		5	5	8
5	BORA	M345		463	463	9
5	BPAT.NWMT	BORA		251	251	10
5	BPAT.NWMT	BRDY		45	45	11
5	BPAT.NWMT	LAGRANDE		206	206	12
5	BPAT.NWMT	M345		1,301	1,301	13
5	BRDY	AVAT.NWMT		35	35	14
5	BRDY	BORA		2,628	2,628	15
5	BRDY	BORA		4,560	4,560	16
5	BRDY	BPAT.NWMT		27	27	17
5	BRDY	LAGRANDE		12,846	12,846	18
5	BRDY	M345		7,507	7,507	19
5	ENPR	BORA		131	131	20
5	ENPR	JBSN		437	437	21
5	GSHN	BPAT.NWMT		50	50	22
5	HMWY	BORA		143	143	23
5	HMWY	BRDY		45	45	24
5	HMWY	M345		1,843	1,843	25
5	JBSN	BORA		4,204	4,204	26
5	JBSN	BRDY		656	656	27
5	JBSN	M345		200	200	28
5	JEFF	BORA		17,863	17,863	29
5	JEFF	BORA		795	795	30
5	JEFF	BRDY		633	633	31
5	JEFF	LAGRANDE		4,509	4,509	32
5	JEFF	M345		12,949	12,949	33
5	JEFF	M345		926	926	34
			0	**6,075,120**	**6,075,120**	

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

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LAGRANDE	BORA		342	342	1
5	LAGRANDE	BRDY		2,355	2,355	2
5	LAGRANDE	JBSN		1,257	1,257	3
5	LAGRANDE	M345		3,412	3,412	4
5	LOLO	BORA		66	66	5
5	LOLO	BRDY		15	15	6
5	LOLO	JBSN		2	2	7
5	LOLO	M345		375	375	8
5	M345	AVAT.NWMT		75	75	9
5	M345	BPAT.NWMT		204	204	10
5	M345	JEFF		33	33	11
5	M345	LAGRANDE		315	315	12
5	BORA	ENPR		2,290	2,290	13
5	BORA	KPRT		643,617	643,617	14
5	BORA	LAGRANDE		794	794	15
5	BORA	M345		1,921	1,921	16
5	BRDY	BORA		1,939	1,939	17
5	BRDY	BRDY		3,895	3,895	18
5	ENPR	BORA		98,299	98,299	19
5	ENPR	LAGRANDE		241	241	20
5	ENPR	M345		556	556	21
5	JBWT	BRDY		398,590	398,590	22
5	JBWT	ENPR		11,242	11,242	23
5	JBWT	HMWY		347,275	347,275	24
5	JBWT	LAGRANDE		12,820	12,820	25
5	JBWT	M500		272,299	272,299	26
5	LAGRANDE	BORA		29,588	29,588	27
5	LAGRANDE	BORA		6,262	6,262	28
5	LOLO	BORA		33,621	33,621	29
5	LOLO	ENPR		201	201	30
5	BORA	LAGRANDE		50	50	31
5	JEFF	LAGRANDE		105	105	32
5	M345	LAGRANDE		50	50	33
5	BRDY	LAGRANDE		968	968	34
			0	**6,075,120**	**6,075,120**	

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

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

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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	BRDY		211	211	1
5	JEFF	LAGRANDE		3,844	3,844	2
5	LOLO	BRDY		180	180	3
5	LOLO	JBSN		280	280	4
5	LAGRANDE	M345		210	210	5
5	AVAT.NWMT	BORA		301	301	6
5	BORA	M345		1,515	1,515	7
5	BPAT.NWMT	BORA		553	553	8
5	BPAT.NWMT	BORA		9,381	9,381	9
5	JBSN	BORA		28	28	10
5	JBSN	BORA		2,114	2,114	11
5	JBSN	BRDY		61	61	12
5	JBSN	JEFF		685	685	13
5	JEFF	BORA		969	969	14
5	JEFF	BRDY		21	21	15
5	LOLO	BORA		46,623	46,623	16
5	LOLO	BORA		19,117	19,117	17
5	LOLO	M345		940	940	18
5	LOLO	M345		2,527	2,527	19
5	BRDY	LAGRANDE		2,723	2,723	20
5	BRDY	M345		4,041	4,041	21
5	HMWY	BRDY		241	241	22
5	HMWY	M345		4,551	4,551	23
5	JEFF	LAGRANDE		544	544	24
5	JEFF	M345		1,224	1,224	25
5	LAGRANDE	BRDY		392	392	26
5	LAGRANDE	M345		5,417	5,417	27
5	LAGRANDE	M345		2,686	2,686	28
5	LOLO	M345		6	6	29
5	LYPK	BRDY		100	100	30
5	LYPK	LAGRANDE		73	73	31
5	M345	BRDY		279	279	32
5	M345	LAGRANDE		3,602	3,602	33
5	MDSK	LAGRANDE		442	442	34
			0	**6,075,120**	**6,075,120**	

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

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(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	MNHM	LAGRANDE		16	16	1
5	BORA	M345		2,085	2,085	2
5	BRDY	M345		36,131	36,131	3
5	BRDY	M345		4,920	4,920	4
5	HMWY	M345		3,346	3,346	5
5	JBSN	M345		905	905	6
5	JEFF	M345		28,490	28,490	7
5	LAGRANDE	M345		4,201	4,201	8
5	LOLO	M345		19,793	19,793	9
5	M345	BORA		50	50	10
5	M345	BRDY		215	215	11
5	M345	LAGRANDE		425	425	12
5	LAGRANDE	BORA		97	97	13
5	HMWY	BORA		290	290	14
5	LAGRANDE	BORA		801	801	15
5	LAGRANDE	BRDY		24	24	16
5	BORA	LAGRANDE		767	767	17
5	BORA	M345		97	97	18
5	BPAT.NWMT	BORA		15	15	19
5	BPAT.NWMT	BRDY		74	74	20
5	BPAT.NWMT	M345		8	8	21
5	BRDY	BORA		43	43	22
5	GSHN	LAGRANDE		180	180	23
5	LAGRANDE	BORA		6,335	6,335	24
5	LAGRANDE	LOLO		85	85	25
5	LAGRANDE	M345		964	964	26
5	LOLO	BORA		85	85	27
5	LOLO	M345		16	16	28
5	M345	BORA		12	12	29
5	M345	LAGRANDE		267	267	30
5	OBBLPR	BORA		84	84	31
5	BORA	M345		8,833	8,833	32
						33
						34
			0	**6,075,120**	**6,075,120**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

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

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	6,860		6,860	1
	865		865	2
	287		287	3
	9,904		9,904	4
	19		19	5
	669		669	6
	6,576		6,576	7
	170		170	8
	276,371		276,371	9
	8,171		8,171	10
	14,248		14,248	11
	823		823	12
	2,735		2,735	13
	20,451		20,451	14
	310		310	15
	91		91	16
	253		253	17
	653		653	18
	3,181		3,181	19
	53		53	20
	132		132	21
	14,524		14,524	22
	91		91	23
	140		140	24
	37,090		37,090	25
	1,027		1,027	26
	1,326		1,326	27
	170		170	28
	181		181	29
	298		298	30
	349,343		349,343	31
	4,537		4,537	32
	206,772		206,772	33
	65,338		65,338	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	35,761		35,761	1
	4,896		4,896	2
	30,722		30,722	3
	42,058		42,058	4
	7,124		7,124	5
	7,778		7,778	6
	7,551		7,551	7
	2,214		2,214	8
	585		585	9
	2,648		2,648	10
	230		230	11
	4,031		4,031	12
	1,292		1,292	13
	3,026		3,026	14
	2,305		2,305	15
	3,026		3,026	16
	1,266		1,266	17
	9,851		9,851	18
	34,375		34,375	19
	14,811		14,811	20
	3,039		3,039	21
	7,412		7,412	22
	4		4	23
	275		275	24
	283		283	25
	1,806		1,806	26
	590		590	27
	3,147		3,147	28
	15,279		15,279	29
	6,987		6,987	30
	16,649		16,649	31
	5,696		5,696	32
	5,775		5,775	33
	34,725		34,725	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	236		236	1
	429		429	2
	31,901		31,901	3
	64,364		64,364	4
	787		787	5
	2,140		2,140	6
	98		98	7
	1,507		1,507	8
	63,085		63,085	9
	14,776		14,776	10
	218,858		218,858	11
	103,640		103,640	12
	393		393	13
	1,574		1,574	14
	4,312		4,312	15
	850		850	16
	3,777		3,777	17
	4,799		4,799	18
	16,145		16,145	19
	421		421	20
	2,640		2,640	21
	42,353		42,353	22
	29,847		29,847	23
	4,017		4,017	24
	4,382		4,382	25
	39		39	26
	31,802		31,802	27
	2,895		2,895	28
	53,852		53,852	29
	45,201		45,201	30
	6,066		6,066	31
	205,436		205,436	32
	66,803		66,803	33
	37,601		37,601	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	250,043		250,043	1
	2,065		2,065	2
	1,058		1,058	3
	1,192		1,192	4
	590		590	5
	665		665	6
	1,003		1,003	7
	17,927		17,927	8
	9,815		9,815	9
	201		201	10
	27,518		27,518	11
	80,414		80,414	12
	1,028,717		1,028,717	13
	59		59	14
	940		940	15
	173		173	16
	909		909	17
	323		323	18
	4,028		4,028	19
	2,392		2,392	20
	4		4	21
	6,294		6,294	22
	381		381	23
	162		162	24
	1,116		1,116	25
	558		558	26
	623		623	27
	15,323		15,323	28
	3,389		3,389	29
	22,140		22,140	30
	14,088		14,088	31
	227		227	32
	14,167		14,167	33
	104		104	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	522		522	1
	180		180	2
	3,032		3,032	3
	580		580	4
	24		24	5
	938		938	6
	1,161		1,161	7
	20		20	8
	1,840		1,840	9
	998		998	10
	179		179	11
	819		819	12
	5,171		5,171	13
	139		139	14
	10,445		10,445	15
	18,123		18,123	16
	107		107	17
	51,055		51,055	18
	29,836		29,836	19
	521		521	20
	1,737		1,737	21
	199		199	22
	568		568	23
	179		179	24
	7,325		7,325	25
	16,708		16,708	26
	2,607		2,607	27
	795		795	28
	70,994		70,994	29
	3,160		3,160	30
	2,516		2,516	31
	17,920		17,920	32
	51,464		51,464	33
	3,680		3,680	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

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

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

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

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

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

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	693		693	1
	12,632		12,632	2
	591		591	3
	920		920	4
	510		510	5
	916		916	6
	4,611		4,611	7
	1,683		1,683	8
	28,553		28,553	9
	85		85	10
	6,434		6,434	11
	186		186	12
	2,085		2,085	13
	2,949		2,949	14
	64		64	15
	141,905		141,905	16
	58,186		58,186	17
	2,861		2,861	18
	7,691		7,691	19
	14,753		14,753	20
	21,894		21,894	21
	1,306		1,306	22
	24,657		24,657	23
	2,947		2,947	24
	6,631		6,631	25
	2,124		2,124	26
	29,349		29,349	27
	14,553		14,553	28
	33		33	29
	542		542	30
	396		396	31
	1,512		1,512	32
	19,516		19,516	33
	2,395		2,395	34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	87		87	1
	6,894		6,894	2
	119,462		119,462	3
	16,267		16,267	4
	11,063		11,063	5
	2,992		2,992	6
	94,197		94,197	7
	13,890		13,890	8
	65,442		65,442	9
	165		165	10
	711		711	11
	1,405		1,405	12
	626		626	13
	792		792	14
	2,187		2,187	15
	66		66	16
	2,841		2,841	17
	359		359	18
	56		56	19
	274		274	20
	30		30	21
	159		159	22
	667		667	23
	23,462		23,462	24
	315		315	25
	3,570		3,570	26
	315		315	27
	59		59	28
	44		44	29
	989		989	30
	311		311	31
	33,201		33,201	32
				33
				34
6,753,825	**14,300,873**	**0**	**21,054,698**	

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

5, Open Access Transmission Tariff, Volume 5, first revision

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2014. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 20, 2028. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Legacy, contract prior to the Open Access Transmission Tariff

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

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

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

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

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

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

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

Legacy, contract prior to the Open Access Transmission Tariff

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	34,954	34,954		251,314		251,314
2	Avista Corp-WWP Div	SFP	319,770	319,770		1,556,759		1,556,759
3	Bonneville Power Admin	LFP	268,990	268,990	1,531,616			1,531,616
4	Bonneville Power Admin	OS					7,453	7,453
5	Bonneville Power Admin	NF	1,127	1,127		13,345		13,345
6	Bonneville Power Admin	SFP	1,997	1,997		12,539		12,539
7	Cargill Power Markets	OS					-1,944	-1,944
8	Northwestern Energy	LFP	20,259	20,259	199,600			199,600
9	NorthWesern Energy	NF	1,993	1,993		10,947		10,947
10	NorthWestern Energy	SFP	83,567	83,567		557,646		557,646
11	PacifiCorp Inc.	LFP	52,522	52,522		922,740		922,740
12	PacifiCorp Inc.	NF	23,600	23,600		249,998		249,998
13	PacifiCorp Inc.	SFP	14,331	14,331		121,385		121,385
14	Portland General Ele Co	SFP	93,739	93,739		333,877		333,877
15	Powerex Corp.	OS					-239,216	-239,216
16	PPL EnergyPlus, LLC	SFP	4,032	4,032		13,859		13,859
	TOTAL		1,024,122	1,024,122	1,731,216	4,796,901	-233,707	6,294,410

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Puget Sound Energy, Inc	SFP	3,736	3,736		4,870		4,870
2	Seattle City Light	SFP	94,344	94,344		732,422		732,422
3	Sierra Pacific Power Co	NF	769	769		6,068		6,068
4	Snohomish County PUD	SFP	4,392	4,392		9,132		9,132
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,024,122	1,024,122	1,731,216	4,796,901	-233,707	6,294,410

Schedule Page: 332 Line No.: 3 Column: b
Contract Expiration Date 09/30/2016

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

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

Schedule Page: 332 Line No.: 8 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 11 Column: b
Contract Expiration Date 05/31/2014

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

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

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	410,105
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	405,305
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,176,968
6	Richard Dahl	81,888
7	Christine King	77,294
8	Gary Michael	141,582
9	Richard Reiten	26,144
10	Joan Smith	77,365
11	Jan Packwood	54,750
12	Judith Johansen	72,526
13	Thomas Wilford	69,428
14	Robert Tintsman	78,828
15	Stephen Allred	70,559
16		
17	Chamber of Commerce & Other Civic Organizations	123,491
18		
19	Association of Idaho Cities	2,300
20	Associated Taxpayers of Idaho	22,000
21	Boston College Center for Corporation	5,000
22	Corporate Executive Board	42,750
23	Idaho Association of Commerce & Industry	3,000
24	Idaho Association of Counties	350
25	Idaho Technology Council	10,000
26	National Association of Directors	5,558
27	National HydroPower Association	28,000
28	North American Energy Standard	6,500
29	Northwest Power Pool	131,093
30	Pacific Northwest Utilities	36,824
31	Western Electricity Coordinating Council	837,673
32	Western Energy Institute	28,110
33	Wyoming Taxpayers Association	1,500
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	4,026,891

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

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

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

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

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

A. Summary of Depreciation and Amortization Charges

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

B. Basis for Amortization Charges

Account 404 - Basis used to compute charges:

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

(1) Shoshone-Bannock Tribe License & Use Agreement (Termination date December 31, 2023).
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period).
(3) Swan Falls Relicenisng (Amortized over a 30 year license period).
(4) Computer Software packages (Amortized over a 60 month period from date of purchase).
(5) Shoshone-Bannock Right of Way (Termination date December 31, 2028).
(6) Boardman Retrofit Tech Analysis (Termination date December 31, 2040).

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

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	633	75.00		3.71	R4.0	20.20
13	311.00	147,710	100.00	-10.00	1.70	S1.0	21.30
14	312.10	81,667	60.00	-5.00	1.52	R3.0	21.80
15	312.20	477,479	60.00	-5.00	2.53	R1.5	20.90
16	312.30	4,204	25.00	20.00	2.38	R3.0	7.90
17	314.00	147,772	45.00	-5.00	2.84	S1.0	19.40
18	315.00	68,200	60.00		6.82	S1.5	19.80
19	316.00	14,053	45.00	-5.00	6.60	R0.5	19.00
20	316.10	87	12.00	15.00	8.82	L2.0	6.30
21	316.40	240	12.00	15.00	4.37	L2.0	7.90
22	316.50	83	12.00	15.00	4.33	L2.0	5.10
23	316.60	106	20.00	15.00	4.09	L2.0	18.00
24	316.70	80	20.00	15.00	2.83	L2.0	14.40
25	316.80	1,054	20.00	30.00	8.13	O1.0	16.60
26	316.90	14	35.00	15.00	2.25	S1.0	34.70
27	317.00	10,214					
28	Subtotal Steam	953,596					
29	331.00	157,518	100.00	-25.00	2.52	R2.5	33.00
30	332.10	19,460	95.00	-20.00	1.71	S4.0	39.80
31	332.20	228,211	95.00	-20.00	1.88	S4.0	35.60
32	332.30	5,472			2.03	SQUARE	49.10
33	333.00	200,844	80.00	-5.00	1.81	R3.0	32.60
34	334.00	46,647	50.00	-5.00	2.85	R1.5	26.10
35	335.00	19,686	95.00		2.19	R2.0	28.10
36	335.10	76	15.00		5.41	SQUARE	6.50
37	335.20	364	20.00		4.72	SQUARE	5.30
38	335.30	166	5.00		14.43	SQUARE	3.30
39	336.00	8,118	75.00		2.23	R3.0	21.40
40	Subtotal Hydro	686,562					
41	341.00	133,026			2.89	SQUARE	27.20
42	342.00	7,988	50.00		2.90	S2.5	28.50
43	343.00	226,811	40.00		3.26	S1.5	25.90
44	344.00	73,447	45.00		2.48	S2.0	26.80
45	345.00	95,558	50.00		3.21	S1.5	22.60
46	346.00	5,739	35.00		3.14	S2.5	24.50
47	Subtotal Other	542,569					
48	350.20	31,171	70.00		1.39	R3.0	58.80
49	352.00	70,137	65.00	-35.00	1.84	R3.0	53.70
50	353.00	365,355	50.00	6.00	1.90	R1.5	40.70

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

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	354.00	155,096	65.00	-15.00	1.70	S3.0	50.80
13	355.00	120,356	60.00	-70.00	2.77	R2.0	43.60
14	356.00	182,332	65.00	-40.00	2.25	R2.0	48.50
15	359.00	390	65.00		0.79	R2.5	24.00
16	Subtotal Transmission	924,837					
17	360.22	32	30.00		3.33		30.00
18	361.00	31,354	65.00	-40.00	2.14	R2.5	53.30
19	362.00	189,665	50.00	-5.00	2.00	R1.0	40.20
20	364.00	230,356	44.00	-45.00	3.08	R1.5	31.30
21	365.00	124,012	45.00	-35.00	2.98	R0.5	33.60
22	366.00	46,834	60.00	-20.00	1.95	R2.0	48.40
23	367.00	197,732	46.00	-15.00	2.26	R2.0	35.30
24	368.00	451,212	35.00	-3.00	2.58	R1.0	27.00
25	369.00	56,853	40.00	-40.00	2.55	R2.0	29.50
26	370.00	14,182	22.00	1.00	3.46	O1.0	17.50
27	370.10	56,751	15.00		6.96	S2.5	13.10
28	370.30						
29	371.10	27	12.00	-2.00	2.35	S4.0	9.00
30	371.20	2,838	17.00	-2.00	1.51	R1.5	14.70
31	373.20	4,505	30.00	-25.00	2.41	R1.0	20.60
32	374.00	644					
33	Subtotal Distribution	1,406,997					
34	390.11	27,395	100.00	-5.00	2.58	S0.5	28.80
35	390.12	65,695	55.00	-5.00	1.90	S0.5	44.30
36	390.20	563	35.00		2.15	S3.0	25.70
37	391.11	12,769	20.00		2.88	SQUARE	12.90
38	391.20	21,438	5.00		11.12	SQUARE	3.20
39	391.21	8,588	8.00		11.22	L2.0	5.70
40	392.10	766	12.00	15.00	7.50	L2.0	8.90
41	392.30	2,590	10.00	50.00	1.73	S2.5	3.40
42	392.40	19,800	12.00	15.00	7.36	L2.0	6.80
43	392.50	882	12.00	15.00	3.53	L2.0	9.00
44	392.60	30,787	20.00	15.00	4.14	L2.0	13.40
45	392.70	5,635	20.00	15.00	3.21	L2.0	12.50
46	392.90	4,431	35.00	15.00	2.10	S1.0	24.30
47	393.00	1,878	25.00		3.30	SQUARE	19.40
48	394.00	6,466	20.00		4.13	SQUARE	13.30
49	395.00	12,255	20.00		4.29	SQUARE	12.10
50	396.00	11,496	20.00	30.00	1.66	O1.0	17.60

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

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	397.10	5,582	15.00		4.25	SQUARE	8.30
13	397.20	27,115	15.00		5.38	SQUARE	9.80
14	397.30	3,612	15.00		5.31	SQUARE	8.00
15	397.40	3,621	10.00		7.90	SQUARE	6.50
16	398.00	5,622	15.00		5.20	SQUARE	10.60
17	Subtotal General	278,986					
18	Total Plant	4,793,547					
19							
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

REGULATORY COMMISSION EXPENSES

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

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

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

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	3,862,917					2
							3
Electric	928	381,035					4
							5
							6
Electric	928	326,544					7
							8
		158,501					9
							10
							11
Electric	928	150,024					12
Electric	928	270,004					13
Electric	928	4,712					14
							15
							16
Electric	928	9,755					17
							18
							19
Electric	928	150,392					20
Electric	928	39,012					21
Electric	928	19,098					22
Electric	928	30,421					23
Electric	928	26,890					24
Electric	928	50,113					25
Electric	928	52,332					26
Electric	928	26,573					27
Electric	928	32,513					28
Electric	928	19,785					29
Electric	928	81,865					30
							31
							32
							33
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							45
		5,692,486					46

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

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	Idaho Power did not incur any Research and	
2	Development expenditures in 2012.	
3		
4		
5		
6		
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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	04/15/2013	End of 2012/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
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DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	20,049,754		
4	Transmission	6,731,505		
5	Regional Market			
6	Distribution	17,301,055		
7	Customer Accounts			
8	Customer Service and Informational	8,412,128		
9	Sales	4,648,046		
10	Administrative and General	42,810,041		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	99,952,529		
12	Maintenance			
13	Production	6,116,531		
14	Transmission	3,404,348		
15	Regional Market			
16	Distribution	9,416,231		
17	Administrative and General	1,164,994		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,102,104		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,166,285		
21	Transmission (Enter Total of lines 4 and 14)	10,135,853		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	26,717,286		
24	Customer Accounts (Transcribe from line 7)			
25	Customer Service and Informational (Transcribe from line 8)	8,412,128		
26	Sales (Transcribe from line 9)	4,648,046		
27	Administrative and General (Enter Total of lines 10 and 17)	43,975,035		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	120,054,633		120,054,633
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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

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

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,441	27	900	3,220	203	567		451	
2	February	4,439	7	900	3,055	201	567		616	
3	March	4,438	2	800	3,109	212	567		550	
4	Total for Quarter 1	13,318			9,384	616	1,701		1,617	
5	April	4,564	23	1600	3,100	216	567		681	
6	May	4,791	14	1900	3,436	269	567		519	
7	June	5,544	28	2000	4,472	337	567		168	
8	Total for Quarter 2	14,899			11,008	822	1,701		1,368	
9	July	5,864	12	1600	4,861	342	567		94	
10	August	5,489	8	1800	4,482	303	567		137	
11	September	4,720	4	2100	3,773	255	567		125	
12	Total for Quarter 3	16,073			13,116	900	1,701		356	
13	October	4,243	26	900	3,367	182	567		127	
14	November	4,362	12	1900	3,499	193	567		103	
15	December	4,499	18	900	3,660	200	567		72	
16	Total for Quarter 4	13,104			10,526	575	1,701		302	
17	Total Year to Date/Year	57,394			44,034	2,913	6,804		3,643	

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

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,085,316
3	Steam	5,227,055			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	7,956,343			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,183,262
7	Other	675,603			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,859,001	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	3,667,462	27	Total Energy Losses	1,253,953
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,522,531
12	Received	392,313			
13	Delivered	395,257			
14	Net Exchanges (Line 12 minus line 13)	-2,944			
15	Transmission For Other (Wheeling)				
16	Received	6,074,132			
17	Delivered	6,075,120			
18	Net Transmission for Other (Line 16 minus line 17)	-988			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,522,531			

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

Page 329 column I differs from Page 401 by 988 MWH, reported for Lucky Peak variation and BPA Energy Imbalance schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only. However the numbers on page 401 have to be adjusted for account 447 transmission.

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

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Idaho Power Company

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

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

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	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)	717			60		
7	Plant Hours Connected to Load	8784			5561		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	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	4374213000			230176000		
13	Cost of Plant: Land and Land Rights	106610			494358		
14	Structures and Improvements	13910931			66823285		
15	Equipment Costs	60588342			460074757		
16	Asset Retirement Costs	0			0		
17	Total Cost	74605883			527392400		
18	Cost per KW of Installed Capacity (line 17/5) Including	96.8279			8214.8349		
19	Production Expenses: Oper, Supv, & Engr	222901			590272		
20	Fuel	103402312			4991249		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5203040			424389		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	6278439			473728		
27	Rents	285311			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	133909			197376		
30	Maintenance of Structures	0			166		
31	Maintenance of Boiler (or reactor) Plant	8136821			128927		
32	Maintenance of Electric Plant	2261009			1817633		
33	Maintenance of Misc Steam (or Nuclear) Plant	4717009			36324		
34	Total Production Expenses	130640751			8660064		
35	Expenses per Net KWh	0.0299			0.0376		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2404401	6419	0	140346	1243	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9325	140000	0	8345	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	38.245	142.680	0.000	30.960	134.052	0.000
41	Average Cost of Fuel per Unit Burned	42.626	98.502	0.000	34.221	128.858	0.000
42	Average Cost of Fuel Burned per Million BTU	2.275	16.752	0.000	2.046	22.104	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.022	0.000	0.000
44	Average BTU per KWh Net Generation	10307.000	0.000	0.000	10228.000	0.000	0.000

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

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

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

Line No.	Item (a)	Plant Name: *Langley Gulch* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2012	
4	Year Last Unit was Installed	2012	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	318.45	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	305	0
7	Plant Hours Connected to Load	1907	0
8	Net Continuous Plant Capability (Megawatts)	300	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	16	0
12	Net Generation, Exclusive of Plant Use - KWh	549705000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	125862894	0
15	Equipment Costs	241906961	0
16	Asset Retirement Costs	0	0
17	Total Cost	370057116	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1162.0572	0
19	Production Expenses: Oper, Supv, & Engr	727729	0
20	Fuel	16873841	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1597922	0
26	Misc Steam (or Nuclear) Power Expenses	226959	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	45424	0
31	Maintenance of Boiler (or reactor) Plant	17345	0
32	Maintenance of Electric Plant	186031	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	19675251	0
35	Expenses per Net KWh	0.0358	0.0000

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	2261741	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1027	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.461	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	7.461	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.350	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	4226.000	0.000	0.000	0.000	0.000	0.000

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

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

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2008			2005			4
283.50			270.90			172.80			5
261			224			178			6
7881			541			397			7
0			261			164			8
0			0			0			9
0			0			0			10
0			9			4			11
622666000			72685000			53194000			12
1106140			402745			0			13
66975806			5679993			1471166			14
274376410			107792021			58946771			15
0			0			0			16
342458356			113874759			60417937			17
1207.9660			420.3572			349.6408			18
589570			344837			148572			19
26107543			5908249			3626466			20
0			0			0			21
2652194			0			0			22
0			0			0			23
0			0			0			24
1539354			294777			277326			25
1579676			103559			43651			26
0			0			0			27
0			0			0			28
71			0			0			29
758837			80801			73394			30
4339854			4922			38360			31
1060665			2087452			289155			32
243285			0			0			33
38871049			8824597			4496924			34
0.0624			0.1214			0.0845			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
346327	14997	0	764057	0	0	568185	0	0	38
9853	138778	0	1027	0	0	1027	0	0	39
36.543	132.895	0.000	7.733	0.000	0.000	6.383	0.000	0.000	40
69.462	132.880	0.000	7.733	0.000	0.000	6.383	0.000	0.000	41
3.525	22.798	0.000	5.440	0.000	0.000	4.480	0.000	0.000	42
0.042	0.000	0.000	0.081	0.000	0.000	0.068	0.000	0.000	43
11101.000	0.000	0.000	10796.000	0.000	0.000	10970.000	0.000	0.000	44

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

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

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

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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.

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	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)	100	77
7	Plant Hours Connect to Load	6,872	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	352,580,000	367,568,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,358
15	Structures and Improvements	11,855,142	1,085,815
16	Reservoirs, Dams, and Waterways	4,293,075	8,413,888
17	Equipment Costs	31,904,332	8,423,020
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,767,143	19,177,558
21	Cost per KW of Installed Capacity (line 20 / 5)	539.1890	255.7008
22	Production Expenses		
23	Operation Supervision and Engineering	476,609	927,261
24	Water for Power	1,577,186	628,163
25	Hydraulic Expenses	97,084	597,445
26	Electric Expenses	51,463	48,134
27	Misc Hydraulic Power Generation Expenses	63,884	79,638
28	Rents	155	3,034
29	Maintenance Supervision and Engineering	13,233	23,041
30	Maintenance of Structures	124,229	72,264
31	Maintenance of Reservoirs, Dams, and Waterways	243	276,980
32	Maintenance of Electric Plant	234,659	63,965
33	Maintenance of Misc Hydraulic Plant	82,341	130,468
34	Total Production Expenses (total 23 thru 33)	2,721,086	2,850,393
35	Expenses per net KWh	0.0077	0.0078

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	441	24
7	Plant Hours Connect to Load	8,772	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,084,203,000	167,365,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,870,863	2,794,963
16	Reservoirs, Dams, and Waterways	52,738,008	6,262,987
17	Equipment Costs	18,085,610	4,403,230
18	Roads, Railroads, and Bridges	819,192	309,805
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	76,390,974	13,976,361
21	Cost per KW of Installed Capacity (line 20 / 5)	195.1238	642.0010
22	Production Expenses		
23	Operation Supervision and Engineering	404,945	272,806
24	Water for Power	271,901	686,421
25	Hydraulic Expenses	632,125	163,775
26	Electric Expenses	156,482	37,579
27	Misc Hydraulic Power Generation Expenses	534,981	32,552
28	Rents	53,355	0
29	Maintenance Supervision and Engineering	47,425	13,111
30	Maintenance of Structures	58,661	19,136
31	Maintenance of Reservoirs, Dams, and Waterways	294,579	38,130
32	Maintenance of Electric Plant	375,770	156,049
33	Maintenance of Misc Hydraulic Plant	1,002,621	106,508
34	Total Production Expenses (total 23 thru 33)	3,832,845	1,526,067
35	Expenses per net KWh	0.0018	0.0091

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	14
7	Plant Hours Connect to Load	8,784	6,035
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	218,236,000	65,937,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,027,032	1,231,506
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	8,693,529	4,550,600
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	16,521,490	6,659,219
21	Cost per KW of Installed Capacity (line 20 / 5)	478.8838	532.7375
22	Production Expenses		
23	Operation Supervision and Engineering	547,441	286,537
24	Water for Power	337,882	139,168
25	Hydraulic Expenses	578,598	116,243
26	Electric Expenses	64,611	31,015
27	Misc Hydraulic Power Generation Expenses	86,664	35,336
28	Rents	0	30
29	Maintenance Supervision and Engineering	16,266	12,583
30	Maintenance of Structures	110,854	101,919
31	Maintenance of Reservoirs, Dams, and Waterways	171,031	901
32	Maintenance of Electric Plant	57,080	118,936
33	Maintenance of Misc Hydraulic Plant	96,409	69,371
34	Total Production Expenses (total 23 thru 33)	2,066,836	912,039
35	Expenses per net KWh	0.0095	0.0138

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

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

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
93	23	51	6
8,780	8,754	6,898	7
			8
91	24	53	9
84	14	50	10
5	4	4	11
464,505,000	127,279,000	166,426,000	12
			13
5,476,746	51,675	255,499	14
9,266,487	25,469,343	10,891,616	15
10,697,169	13,856,887	7,908,870	16
12,306,266	30,416,395	20,731,334	17
248,183	835,946	1,917,603	18
0	0	0	19
37,994,851	70,630,246	41,704,922	20
458.8750	2,825.2098	790.7645	21
			22
1,090,503	766,824	343,165	23
689,076	402,783	180,435	24
1,005,259	503,308	168,886	25
70,368	14,618	53,776	26
131,381	77,054	46,602	27
32,673	8,014	1,122	28
25,825	17,358	8,672	29
56,461	62,762	38,469	30
122,743	86,970	15,145	31
341,903	215,803	122,610	32
125,736	110,956	140,702	33
3,691,928	2,266,450	1,119,584	34
0.0079	0.0178	0.0067	35

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

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	60	59	6
0	8,773	5,464	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	248,940,000	175,182,000	12
			13
114,367	424,428	138,100	14
26,681,738	2,826,153	10,354,284	15
13,556,785	6,920,148	17,114,934	16
1,792,250	8,062,473	27,720,868	17
99,051	88,693	501,877	18
0	0	0	19
42,244,191	18,321,895	55,830,063	20
0.0000	305.3649	939.1096	21
			22
0	681,142	395,884	23
0	285,885	1,716,901	24
6,559,288	240,393	79,771	25
0	95,961	34,738	26
78	78,931	65,495	27
0	1,311	1,553	28
0	22,026	12,366	29
0	60,939	115,036	30
0	5,757	7,949	31
0	336,611	118,770	32
130,569	106,936	56,008	33
6,689,935	1,915,892	2,604,471	34
0.0000	0.0077	0.0149	35

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.

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

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	2.3	16,883	1,759,923
3	Thousand Springs	1912	8.80	7.5	56,539	9,359,404
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	3.0	19	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
703,969	167,698		150,624			2
1,063,569	223,097		152,979			3
						4
						5
						6
181,852				Diesel		7
						8
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2013	Year/Period of Report End of 2012/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Borah	Midpoint	345.00	500.00	S Tower	85.17		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.40		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		1
5								
6	Jim Bridger	Goshen	345.00	345.00	S Tower	226.16		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.04		2
8	Kinport	Borah	345.00	345.00	S Tower	27.10		1
9	Midpoint	Borah #1	345.00	345.00	H Wood	79.31		1
10	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
11	Adelaide Tap	Adelaide	345.00	345.00	H Wood	3.55		2
12								
13	Quartz	LaGrande	230.00	230.00	H Wood	46.27		1
14	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
15	Brady	Antelope	230.00	230.00	H Wood	56.41		1
16	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
17	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
18	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
19	Brownlee	Ontario	230.00	230.00	S Tower	72.74		1
20	Mora	Bowmont	138.00	230.00	S P Wood	9.91		1
21	Mora	Bowmont	138.00	230.00	H Wood	8.82		1
22	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
23	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
24	Boise Bench	Caldwell	230.00	230.00	S Tower	7.58		1
25	Boise Bench	Caldwell	230.00	230.00	H Wood	33.68		1
26	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.94		2
27	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
28	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.05		2
29	Caldwell	Ontario	230.00	230.00	H Wood	29.97		1
30	Caldwell	Ontario	230.00	230.00	S Tower	3.27		1
31	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
32	Borah	Hunt	230.00	230.00	H Steel	68.22		1
33	Danskin	Hubbard	230.00	230.00	H Steel	36.25		1
34	Danskin	Hubbard	230.00	230.00	SP Steel	1.90		1
35	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
36					TOTAL	4,778.91	11.02	190

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

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.37		1
2	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
3	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
4	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
5	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
6	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.49		1
7	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
8	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.32		1
9	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
10	Oxbow	Brownlee	230.00	230.00	S Tower	10.40		2
11	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
12	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
13	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.08		2
14	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
15	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.04		2
16	Brownlee	Boise Bench	230.00	230.00	S Tower	102.54		2
17	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.30		1
18	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
19	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
20	Borah	Brady #2	230.00	230.00	H Wood	3.56		1
21	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
22								
23	Goshen	State Line	161.00	161.00	H Wood	90.60		1
24	Don	Goshen	161.00	161.00	S Tower	2.37		2
25	Don	Goshen	161.00	161.00	H Wood	48.43		2
26								
27	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.22		2
28	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
29	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.13		2
30	Nampa	Caldwell	138.00	138.00	S P Wood	11.10		2
31	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.35		1
32	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
33	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
34	Brady	Fremont	138.00	138.00	S Tower	1.00		2
35	Brady	Fremont	138.00	138.00	H Wood	24.32		2
36					TOTAL	4,778.91	11.02	190

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
2	King	Lower Malad	138.00	138.00	H Wood	84.78		2
3	Emmett Jct	Payette	138.00	138.00	H Wood	66.41		2
4	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
5	Ontario	Quartz	138.00	138.00	H Wood	73.40		1
6	King	American Falls PP	138.00	138.00	S Tower	1.01		2
7	King	American Falls PP	138.00	138.00	H Wood	141.74		1
8	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
9	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
10	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
11	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
12	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
13	King	Wood River	138.00	138.00	H Wood	73.74		1
14	Boise Bench	Grove	138.00	138.00	S P Wood	10.58		2
15	Quartz	John Day	138.00	138.00	H Wood	67.32		1
16	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
17	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
18	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
19	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
20	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
21	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
22	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
23	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
24	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
25	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
26	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
27	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
28	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.50		1
29	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.47		2
30	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
31	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.20		2
32	Twin Falls	Russett	138.00	138.00	S P Wood	1.72		1
33	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
34	Peterson	Tendoy	69.00	138.00	H Wood	57.23		1
35	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
36					TOTAL	4,778.91	11.02	190

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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.83		2
2	Boise Bench	Mora	138.00	138.00	H Wood	13.15		2
3	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
4	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
5	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.24	2.98	1
6	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
7	Eagle	Star	138.00	138.00	S P Wood	6.37		1
8	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.08		1
9	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
10	Victory Jct	Victory	138.00	138.00	S P Steel	1.90		1
11	Butler	Wye	138.00	138.00	S P Steel	2.94		1
12	Horseflat	Starkey	138.00	138.00	H Wood	34.53		1
13	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
14	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
15	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
16	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
17	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.79		1
18	Garnet	Ward		138.00				
19	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
20	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
21	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
22	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
23	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
24	Valivue Tap		138.00	138.00	S P Steel	0.80		2
25	Bowmont	Happy Valley	138.00	138.00	S P Steel			1
26	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
27	Donn	HOKU	138.00	138.00	S P Steel	2.68		1
28	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
29	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
30	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
31	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.29		1
32	King	Justice	138.00	138.00	S P Wood	0.11		1
33	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
34	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
35	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
36					TOTAL	4,778.91	11.02	190

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

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	C J Strike	Strike Jct	138.00	138.00	S Tower	4.32		2
2	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.44		1
3	Strike Jct	Bowmont		138.00	H Wood	0.05		1
4	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
5	Strike Jct	Bowmont	138.00	138.00	H Wood	68.24		1
6	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
7	Bliss	King	138.00	138.00	H Wood	10.48		1
8	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
9	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
10								
11								
12								
13	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
14								
15								
16	69 Kv Lines		69.00	69.00	H Wood	167.03		1
17	69 Kv Lines		69.00	69.00	S P Wood	938.98		1
18								
19								
20	46 Kv Lines		46.00	46.00	S P Wood	407.98		1
21								
22	Total all lines					4,778.91	11.02	190
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,778.91	11.02	190

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.
1272 ACSR	256,381	21,787,333	22,043,714					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		836,006	836,006					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,889,116	17,372,425					6
795 ACSR	571,979	11,048,287	11,620,266					7
1272 ACSR	344,220	6,008,061	6,352,281					8
715.5 ACSR	283,143	6,380,747	6,663,890					9
715.5 ACSR	64,851	12,281,414	12,346,265					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	5,537,611	5,599,829					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	3,058,249	3,166,550					15
795 ACSR		6,186	6,186					16
715.5 ACSR	18,829	969,871	988,700					17
1272 ACSR	1,190	51,525	52,715					18
2X954 ACSR	1,676,838	20,541,790	22,218,628					19
715.5 ACSR	413,793	2,198,731	2,612,524					20
715.5 ACSR								21
1272 ACSR	1,899	212,523	214,422					22
1590 ACSR	2,138,236	8,775,086	10,913,322					23
1272 ACSR	1,748,214	7,009,570	8,757,784					24
715.5 ACSR								25
1272 ACSR	3,062,812	6,980,098	10,042,910					26
795 AAC		80,895	80,895					27
954 ACSR	34,174	16,026,470	16,060,644					28
2X954 ACSR	236,152	9,192,894	9,429,046					29
1272 ACSR								30
1272 ACSR	81,701	1,666,354	1,748,055					31
1590 ACSR	624,917	22,457,621	23,082,538					32
1590 ACSR		15,210,561	15,210,561					33
1590 ACSR								34
1590 ACSR								35
	31,516,529	460,340,116	491,856,645					36

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

TRANSMISSION LINE STATISTICS (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
1590 ACSR	948,166	9,078,827	10,026,993					3
1272 ACSR								4
715.5 ACSR	385,287	5,595,136	5,980,423					5
715.5 ACSR								6
795 ACSR	53,068	2,799,473	2,852,541					7
795 ACSR								8
VARIOUS	289,934	9,016,582	9,306,516					9
1272 ACSR	14,810	1,241,047	1,255,857					10
715.5 ACSR	227,825	6,920,209	7,148,034					11
VARIOUS								12
1272 ACSR	87,468	2,171,101	2,258,569					13
1272 ACSR	171,081	1,540,515	1,711,596					14
1272 ACSR	44,687	1,252,130	1,296,817					15
954 ACSR	185,106	6,269,304	6,454,410					16
715.5 ACSR	247,857	11,784,046	12,031,903					17
1272 ACSR	84,014	1,881,398	1,965,412					18
1272 ACSR	3,068	416,606	419,674					19
715.5 ACSR								20
1272 ACSR	10,064	311,349	321,413					21
								22
250 COPPER	16,155	648,382	664,537					23
715.5 ACSR	76,041	1,737,526	1,813,567					24
397.5 ACSR								25
								26
250 COPPER	26,507	338,681	365,188					27
250 COPPER								28
715.5 ACSR	21,327	249,232	270,559					29
795 AAC	646,112	3,152,590	3,798,702					30
795 ACSR	47,687	3,545,932	3,593,619					31
795 ACSR	43,568	913,613	957,181					32
795 AAC	270,823	557,504	828,327					33
VARIOUS	564,932	3,768,756	4,333,688					34
VARIOUS								35
	31,516,529	460,340,116	491,856,645					36

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

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
VARIOUS								1
VARIOUS	76,823	2,302,594	2,379,417					2
VARIOUS	30,918	2,511,404	2,542,322					3
397.5 ACSR	1,955	6,930	8,885					4
VARIOUS	34,428	4,811,314	4,845,742					5
715.5 ACSR	216,919	8,271,471	8,488,390					6
715.5 ACSR								7
715.5 ACSR								8
4\0	4,191	309,857	314,048					9
954 ACSR		96,921	96,921					10
250 COPPER	2,741	122,591	125,332					11
VARIOUS	28,490	2,150,317	2,178,807					12
VARIOUS	173,683	3,037,531	3,211,214					13
VARIOUS	225,602	1,652,772	1,878,374					14
397.5 ACSR	92,173	2,362,416	2,454,589					15
VARIOUS	20	77,199	77,219					16
715.5 ACSR	3,123,380	8,219,053	11,342,433					17
VARIOUS								18
795AAC								19
1272 ACSR								20
250 COPPER	450	187,848	188,298					21
397.5 ACSR	349,712	7,062,297	7,412,009					22
397.5 ACSR								23
397.5 ACSR	109,899	2,306,969	2,416,868					24
397.5 ACSR								25
715.5 ACSR	211,131	1,448,294	1,659,425					26
715.5 ACSR	3,324	1,430,523	1,433,847					27
397.5 ACSR	14,927	587,404	602,331					28
715.5 ACSR	13,734	1,051,324	1,065,058					29
397.5 ACSR	18,223	1,276,855	1,295,078					30
VARIOUS	54,848	3,084,397	3,139,245					31
715.5 ACSR	16,790	206,158	222,948					32
715.5 ACSR	13,616	491,359	504,975					33
397.5 ACSR	395,696	3,449,949	3,845,645					34
715.5 ACSR	343,955	2,137,516	2,481,471					35
	31,516,529	460,340,116	491,856,645					36

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

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 ACSR								1
715.5 ACSR	14,697	637,273	651,970					2
795 AAC		49,642	49,642					3
795 AAC	489,037	2,177,222	2,666,259					4
1272 ACSR	935,725	3,605,765	4,541,490					5
1272 ACSR	34,687	838,605	873,292					6
715.5 ACSR	179,817	2,909,434	3,089,251					7
795 AAC	43,035	434,341	477,376					8
1272 ACSR	140,412	2,577,075	2,717,487					9
1272 ACSR								10
795 ACSR	134,471	1,405,436	1,539,907					11
715.5 ACSR	2,473,833	18,402,119	20,875,952					12
715.5 ACSR								13
715.5 ACSR								14
715.5 ACSR								15
715.5 ACSR								16
1272 ACSR	78,579	1,821,921	1,900,500					17
	40,580		40,580					18
715.5 ACSR	331,539	4,682,879	5,014,418					19
								20
1272 ACSR	272,231	2,141,218	2,413,449					21
795 ACSR								22
795 ACSR								23
795 ACSR		351,497	351,497					24
1272 ACSR	377,296		377,296					25
715.5 ACSR	1,174	212,777	213,951					26
1272 ACSR	190	398	588					27
1272 ACSR								28
795 ACSR								29
795 ACSR								30
795 ACSR		-11,446	-11,446					31
1590 ACSR		70,224	70,224					32
250 COPPER	58	64,441	64,499					33
715.5 ACSR		76,560	76,560					34
397.5 ACSR		4,406	4,406					35
	31,516,529	460,340,116	491,856,645					36

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

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 ACSR	1,074	398,891	399,965					1
397.5 ACSR	4,355	2,259,099	2,263,454					2
715.5 ACSR	86,651	1,866,338	1,952,989					3
715.5 ACSR								4
								5
715.5 ACSR	7	279,481	279,488					6
715.5 ACSR	5,620	997,718	1,003,338					7
715.5 ACSR	2,814	183,606	186,420					8
397.5 ACSR	12,885	261,511	274,396					9
								10
								11
								12
397.5 ACSR	1,978	63,404	65,382					13
								14
								15
VARIOUS	1,507,287	51,235,189	52,742,476					16
VARIOUS								17
								18
								19
VARIOUS	194,536	14,758,767	14,953,303					20
								21
	31,516,529	460,340,116	491,856,645					22
								23
								24
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								30
								31
								32
								33
								34
								35
	31,516,529	460,340,116	491,856,645					36

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

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Langley Gulch	Galloway Rd (str. #117)	14.26	s pole	8.13	1	1
2	Galloway Rd	Willis Tap	2.09	s pole	15.70	1	1
3							
4	King	Justice	0.11	w pole	36.03	1	1
5							
6	Bowmont	Happy Valley	8.60	s pole		1	1
7							
8							
9							
10							
11							
12							
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43							
44	TOTAL		25.06		59.86	4	4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

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

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.09	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.47
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
10	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	13.00	
14	Blackfoot	transmission	161.00	46.00	12.47
15	Blackfoot	distribution	161.00	138.00	12.98
16	Bliss - attended	transmission	138.00	13.80	
17	Blue Gulch	distribution	138.00	35.00	
18	Boise Bench - attended	transmission	230.00	138.00	13.20
19	Boise Bench - attended	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	138.00	69.00	12.98
21	Boise Bench - attended	transmission	230.00	138.00	13.80
22	Boise	distribution	138.00	13.00	
23	Borah	transmission	345.00	230.00	13.80
24	Bowmont	distribution	69.00	46.00	6.90
25	Bowmont	distribution	138.00	35.00	
26	Bowmont	transmission	138.00	69.00	12.98
27	Bowmont	transmission	138.00	69.00	12.47
28	Bowmont	transmission	230.00	138.00	13.80
29	Brady	distribution	46.00	13.00	
30	Brady	transmission	230.00	138.00	13.80
31	Brady	transmission	138.00	46.00	12.47
32	Brady	distribution	69.00	13.00	
33	Brownlee - attended	transmission	230.00	13.80	
34	Bruneau Bridge	distribution	138.00	35.00	
35	Buckhorn	distribution	69.00	35.00	
36	Bucyrus	distribution	46.00	7.20	
37	Buhl	distribution	46.00	13.00	
38	Burley Rural	distribution	69.00	13.00	
39	Butler	distribution	138.00	13.09	
40	Caldwell	distribution	138.00	13.00	

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Caldwell	transmission	230.00	138.00	
2	Caldwell	distribution	138.00	13.09	
3	Caldwell	transmission	138.00	69.00	12.47
4	Caldwell	transmission	230.00	138.00	12.47
5	Caldwell	distribution	13.00	4.16	
6	Canyon Creek	distribution	138.00	35.00	
7	Canyon Creek	transmission	138.00	69.00	12.98
8	Cascade Power Plant - attended	transmission	69.00	4.60	
9	Cascade	distribution	69.00	13.10	
10	Chestnut	distribution	138.00	13.00	
11	Clear Lake - attended	transmission	46.00	2.40	
12	Cliff	transmission	138.00	46.00	12.50
13	Cliff	transmission	138.00	46.00	12.95
14	Cloverdale	distribution	138.00	13.00	
15	Dale	distribution	46.00	4.60	
16	Dale	distribution	46.00	13.00	
17	Dale	distribution	69.00	13.00	
18	Dale	distribution	138.00	36.20	
19	Dale	transmission	138.00	46.00	12.47
20	Danskin- attended	transmission	230.00	18.00	
21	Danskin- attended	transmission	230.00	138.00	13.80
22	Danskin- attended	distribution	18.00	4.16	
23	Danskin- attended	transmission	138.00	12.00	
24	Danskin- attended	distribution	35.00	13.80	
25	Don	distribution	138.00	7.60	
26	Don	distribution	138.00	13.20	
27	Don	distribution	138.00	13.00	
28	Don	distribution	14.00		
29	DRAM	distribution	138.00	13.09	
30	DRAM	transmission	230.00	138.00	13.80
31	DRAM	distribution	138.00	12.47	
32	Duffin	distribution	138.00	35.00	
33	Eagle	distribution	138.00	13.09	
34	Eastgate	distribution	138.00		
35	Eastgate	distribution	138.00	13.00	
36	Eckert	distribution	138.00	36.20	
37	Eden	distribution	138.00	36.20	
38	Eden	transmission	138.00	46.00	12.98
39	Elkhorn	distribution	138.00	12.47	
40	Elkhorn	distribution	138.00	13.00	

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

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Elmore	distribution	138.00	35.00	
2	Elmore	transmission	138.00	69.00	12.50
3	Elmore	transmission	138.00	69.00	12.98
4	Emmett	distribution	138.00		
5	Emmett	transmission	138.00	69.00	12.47
6	Falls	distribution	46.00	13.00	
7	Filer	distribution	46.00	13.00	
8	Flying H	distribution	69.00	2.40	
9	Fort Hall	distribution	46.00	13.00	
10	Fossil Gulch	distribution	138.00	35.00	
11	Fremont	transmission	138.00	46.00	12.50
12	Gary	distribution	138.00	13.09	
13	Gary	distribution	138.00	13.00	
14	Gem	distribution	69.00	13.00	
15	Gem	distribution	69.00		
16	Goodng Rural	distribution	46.00	13.00	
17	Golden Valley	distribution	69.00	13.00	
18	Gowen Substation	distribution	138.00	35.00	
19	Grindstone	distribution	35.00		
20	Grove	distribution	138.00	13.09	
21	Grove	distribution	138.00	13.00	
22	Hagerman	distribution	46.00	13.00	
23	Hagerman	distribution	46.00	13.00	32.00
24	Hailey	distribution	138.00	13.00	
25	Happy Valley	distribution	138.00	13.09	
26	Haven	distribution	138.00	35.00	
27	Haven	transmission	138.00	46.00	
28	Hemingway	transmission	500.00	230.00	34.50
29	Hewlett Packard	distribution	138.00	13.00	
30	Hidden Springs	distribution	138.00	13.00	
31	Highland	distribution	138.00	13.00	
32	Hill	distribution	138.00	13.00	
33	Hillsdale	distribution	138.00		
34	Hoku	distribution	138.00	13.80	
35	Homedale	distribution	69.00	13.00	
36	Horse Flat	transmission	230.00	138.00	13.80
37	Horseshoe Bend	distribution	35.00		
38	Horseshoe Bend	distribution	69.00	36.20	
39	Horseshoe Bend	distribution	69.00	25.00	
40	Huston	distribution	69.00	13.00	

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

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hulen	distribution	46.00	13.00	
2	Hunt	transmission	230.00	138.00	13.80
3	Hydra	distribution	138.00	36.20	
4	Island	distribution	69.00	13.00	
5	Jerome	distribution	138.00	13.00	
6	Jerome	distribution	138.00	13.09	
7	Julion Clawson	distribution	138.00	35.00	
8	Joplin	distribution	138.00	13.00	
9	Joplin	distribution	138.00	35.00	
10	Justice	transmission	230.00	138.00	13.80
11	Karcher	distribution	138.00	13.00	
12	Kenyon	distribution	69.00	13.00	
13	Ketchum	distribution	138.00	13.00	
14	Kimberly	distribution	138.00	13.00	
15	Kinport	transmission	161.00	46.00	13.20
16	Kinport	transmission	230.00	138.00	12.47
17	Kinport	transmission	230.00	138.00	13.80
18	Kinport	transmission	345.00	230.00	13.80
19	Kramer	distribution	138.00	35.00	
20	Kramer	distribution	138.00	36.20	
21	Kuna	distribution	138.00	13.00	
22	Lake Fork	distribution	138.00	36.20	
23	Lake Fork	transmission	138.00	69.00	12.50
24	Lamb	distribution	138.00	13.00	
25	Langley Gulch- attended	transmission	230.00	138.00	13.80
26	Langley Gulch- attended	transmission	230.00		
27	Langley Gulch- attended	distribution		4.16	
28	Langley Gulch- attended	distribution	13.00	4.16	
29	Lansing	distribution	69.00	13.00	
30	Lincoln	distribution	138.00	13.09	
31	Linden	distribution	138.00	13.00	
32	Locust	distribution	138.00	36.20	
33	Locust	transmission	230.00	138.00	13.80
34	Lower Malad - attended	transmission	138.00	7.20	
35	Lower Salmon - attended	transmission	138.00	13.80	
36	Map Rock	distribution	69.00	13.00	
37	McCall	distribution	13.00	13.09	
38	McCall	distribution	138.00	36.20	
39	Meridian	distribution	138.00	13.00	
40	Micron	distribution	138.00	13.09	

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

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Micron	distribution	138.00	13.00	
2	Midpoint	transmission	230.00	138.00	13.80
3	Midpoint	transmission	345.00	230.00	13.80
4	Midpoint	transmission	500.00	345.00	
5	Midrose	distribution	138.00	13.09	
6	Milner	transmission	138.00	69.00	12.47
7	Milner	distribution	69.00	46.00	6.90
8	Milner	distribution	138.00	35.00	
9	Milner PP - attended	transmission	138.00	13.80	
10	Moonstone	distribution	138.00	35.00	
11	Mora	distribution	138.00	35.00	
12	Mora	distribution	138.00	36.20	
13	Moreland	distribution	35.00	13.00	
14	Moreland	distribution	46.00	13.00	
15	Moreland	distribution	46.00	35.00	12.47
16	Mountain Home	distribution	69.00	13.00	
17	Mountain Home Air Force Base	distribution	69.00	13.00	
18	Mountain Home Air Force Base	distribution	138.00	13.00	
19	Nampa	transmission	230.00	138.00	13.80
20	Nampa	distribution	138.00	13.00	
21	New Meadows	distribution	138.00	36.20	
22	New Plymouth	distribution	69.00	13.00	
23	Notch Butte	distribution	138.00	13.09	
24	Orchard	distribution	69.00	36.20	
25	Orchard	distribution	69.00	35.00	12.47
26	Parma	distribution	69.00	13.00	
27	Parma	distribution	69.00	35.00	
28	Paul	distribution	138.00	35.00	
29	Payette	distribution	138.00	13.00	
30	Pingree	transmission	138.00	46.00	12.50
31	Pingree	distribution	138.00	35.00	
32	Pleasant Valley	distribution	138.00	35.00	
33	Pocatello	distribution	46.00	13.00	
34	Poleline	distribution	138.00	13.09	
35	Populus	transmission	345.00		
36	Portneuf	distribution	138.00	35.00	
37	Portneuf	distribution	46.00	35.00	
38	Rockford	distribution	46.00	13.00	
39	Russett	distribution	138.00	13.00	
40	Sailor Creek	distribution	138.00	2.40	

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

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Sailor Creek	distribution	138.00	35.00	
2	Salmon	distribution	69.00	13.00	
3	Salmon	distribution	69.00	34.50	12.47
4	Salmon	distribution	69.00		12.47
5	Salmon	transmission	13.00	2.40	
6	Shoshone	distribution	46.00	13.00	
7	Shoshone	distribution	46.00	7.20	
8	Shoshone Falls - attended	transmission	46.00	2.30	
9	Shoshone Falls - attended	transmission	46.00	6.60	
10	Silver	distribution	138.00	35.00	
11	Simplot	distribution	138.00	13.00	
12	Sinker Creek	distribution	138.00	35.00	
13	Siphon	distribution	138.00	35.00	
14	South Park	distribution	46.00	13.00	
15	Star	distribution	138.00	13.09	
16	Starkey	transmission	138.00	69.00	12.47
17	State	distribution	69.00	13.00	
18	Stoddard	distribution	138.00	13.00	
19	Strike Power Plant - attended	transmission	138.00	13.80	
20	Sugar	distribution	138.00	35.00	
21	Swan Falls - attended	transmission	138.00	6.90	
22	Taber	distribution	46.00	13.00	
23	Ten Mile	distribution	138.00	13.09	
24	Terry	distribution	138.00	13.09	
25	Terry	distribution	138.00	13.00	
26	Thousand Springs - attended	transmission	46.00	7.20	
27	Thousand Springs - attended	transmission	7.00	2.40	
28	Toponis	distribution	138.00	33.00	
29	Twin Falls	distribution	138.00	13.09	
30	Twin Falls	transmission	138.00	46.00	12.98
31	Twin Falls PP - attended	transmission	138.00	7.20	
32	Twin Falls PP - attended	transmission	138.00	13.20	
33	Upper Malad - attended	transmission	45.00	7.20	
34	Upper Salmon- attended	transmission	138.00	7.20	
35	Ustick	distribution	138.00	13.00	
36	Vallivue	distribution	138.00	13.09	
37	Victory	distribution	138.00	13.00	
38	Victory	distribution	138.00	13.09	
39	Ware	distribution	69.00	13.00	
40	Weiser	distribution	69.00	13.00	

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1	Weiser	transmission	138.00	69.00	12.47
2	Wilder	distribution	69.00	13.00	
3	Willis	distribution	138.00	13.09	
4	Wye	distribution	138.00	13.00	
5	Wye	distribution	138.00	13.09	
6	Zilog	distribution	138.00	13.09	
7					
8					
9	The above are all State of Idaho				
10					
11	Montana:				
12	Peterson	transmission	230.00	69.00	13.20
13					
14	Nevada:				
15	Valmy - attended	transmission	345.00	125.00	24.90
16	Valmy - attended	transmission	345.00	125.00	24.90
17	Valmy - attended	transmission	120.00	24.90	7.20
18	Valmy - attended	transmission	345.00		
19	Valmy - attended	transmission	345.00		
20	Valmy - attended	transmission	345.00		
21	Valmy - attended	transmission	345.00		
22	Valmy - attended	transmission	345.00		
23	Wells	transmission	138.00	69.00	13.00
24					
25	Oregon:				
26	Boardman - attended	transmission	500.00	24.00	
27	Boardman - attended	transmission	230.00	7.20	
28	Boardman - attended	transmission	24.00	7.20	
29	Cairo	distribution	69.00	13.00	
30	Hells Canyon - attended	transmission	230.00	13.80	
31	Hells Canyon - attended	distribution	69.00	0.50	
32	Hines	transmission	138.00	115.00	12.47
33	Malheur Butte	distribution	69.00	34.50	
34	Nyssa	distribution	69.00	13.00	
35	Ontario	distribution	138.00	13.00	
36	Ontario	transmission	138.00	69.00	12.47
37	Ontario	transmission	230.00	138.00	13.80
38	Ontario	transmission	138.00	69.00	12.98
39	Ontario	transmission	138.00	69.00	13.09
40	Ore-Ida	distribution	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Oxbow - attended	transmission	138.00	69.00	13.00
2	Oxbow - attended	transmission	230.00	13.80	
3	Oxbow - attended	transmission	230.00	138.00	13.80
4	Quartz	transmission	138.00	69.00	12.50
5	Quartz	transmission	230.00	138.00	12.98
6	Quartz	transmission	138.00	69.00	12.98
7	Vale	distribution	69.00	13.00	
8					
9	Wyoming:				
10	Jim Bridger - attended	transmission	345.00	22.00	
11	Jim Bridger - attended	transmission	345.00	230.00	34.50
12					
13					
14					
15					
16					
17	Transformers-distribution substations under 10,000				
18	KVA 85 unattended.				
19					
20					
21					
22					
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38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
50	3	1				14
80	1					15
69	3					16
15	1					17
254	2					18
42	2					19
75	3					20
240	2					21
67	3					22
450	3	1				23
8	3					24
18	1					25
25	1					26
25	1					27
180	1					28
		5				29
312	3					30
		1				31
		1				32
721	5	1				33
30	2					34
20	1					35
6	1	1				36
20	2					37
12	1					38
48	2					39
15	1					40

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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
120	1					1
24	1					2
75	3					3
120	1					4
		1				5
15	1					6
15	1					7
12	1					8
10	1					9
48	2					10
4	1					11
12	2	1				12
4	1					13
48	2					14
		1				15
		6				16
		1				17
27	1					18
25	1					19
140	1					20
180	1					21
6	1					22
96	2					23
5	1					24
		1				25
108	6	3				26
26	1	1				27
80	6					28
118	7					29
160	2					30
17	1					31
36	2					32
38	2					33
24	1					34
18	1					35
18	1					36
24	1					37
15	1					38
8	1					39
8	1					40

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

SUBSTATIONS (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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
17	1					1
15	1					2
15	1					3
24	1					4
25	1					5
18	2					6
10	1					7
15	2					8
10	1	1				9
15	1					10
50	3	1				11
20	1					12
17	1					13
8	1					14
10	1					15
15	2					16
10	1	1				17
24	1					18
5	2					19
48	2					20
24	1					21
10	1					22
5	1					23
20	1					24
18	1					25
12	1					26
25	1					27
600	3	1				28
20	1					29
8	1					30
18	1					31
39	2					32
24	1					33
		2				34
22	2					35
100	1					36
5	1					37
12	1					38
5	1					39
10	1					40

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

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

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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	2					1
120	1					2
840	2	1				3
750	3	1				4
24	1					5
100	4					6
8	3	1				7
29	2					8
36	1					9
12	1					10
15	1					11
24	1					12
6	1					13
8	1					14
8	4					15
15	1					16
		1				17
18	1					18
180	1					19
50	3					20
12	1					21
10	1					22
10	1					23
6	1					24
10	3					25
10	1					26
12	1					27
36	2					28
23	3					29
50	3					30
22	2					31
42	2					32
36	2					33
18	1					34
						35
18	1					36
		1				37
14	2					38
18	1					39
15	2					40

SUBSTATIONS (Continued)

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

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

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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
10	1					2
18	1					3
36	2					4
20	1					5
24	1					6
						7
						8
						9
						10
						11
30	3	1				12
						13
						14
	1					15
	1					16
	1					17
			Line Reactor	1	48	18
			Line Reactor	1	35	19
			Line Reactor	1	35	20
			Line Reactor	1	35	21
			Line Reactor	1	35	22
20	3	1				23
						24
						25
685	3	1				26
55	1					27
55	1					28
12	1					29
500	3					30
1	1					31
40	1					32
8	3	1				33
20	2					34
38	2					35
25	1	1				36
240	2					37
50	2					38
		1				39
15	1					40

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
10	3	1				1
244	2					2
100	1					3
15	1					4
100	3	1				5
15	1					6
10	1					7
						8
						9
1122	2					10
1084	22					11
						12
						13
						14
						15
						16
						17
350						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Schedule Page: 426.7 Line No.: 11 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	04/15/2013	End of 2012/Q4

TRANSCTIONS 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	IDA	417420	257,667
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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

PUC FORM 559 (11000) (04-07)

STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	$ 50,406,870	$ 51,824,852
3	Operating Expenses			
4	Operation Expenses (401)	8-11	30,623,249	32,008,304
5	Maintenance Expenses (402)	8-11	3,530,772	3,723,074
6	Depreciation Expense (403)	12	4,863,271	4,753,703
7	Amort. & Depl. of Utility Plant (404-405)	12	304,434	291,413
8	Amort. of Utility Plant Acq. Adj. (406)	12	(533)	(980)
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407-411)	12	(8,111)	(16,415)
10	Accretion Expense (411)	12	6,868	
11	Amort. of Conversion Expenses (407)	12		
12	Taxes Other Than Income Taxes (408.1)	13	2,042,432	1,961,968
13	Regulatory Debits/Credits	14	(748,954)	28,099
14	Income Taxes - Federal (409.1)	14	(766,932)	(3,387,983)
15	- Other (409.1)	15	36,314	(71,777)
16	Provision for Deferred Inc. Taxes (410.1)	16-23	10,253,044	2,338,178
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)	16-23	(8,577,258)	(2,000,764)
18	Investment Tax Credit Adj. - Net (411.4)	24	372,045	(48,730)
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20)		41,930,641	39,578,090
22	Net Utility Operating Income (Total of line 2 less 20)		$ 8,476,229	$ 12,246,762

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote).
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.		OPERATING REVENUES		MEGAWATT HOURS SOLD		AVG NO OF CUSTOMERS PER MONTH		Line No.
		Amount for Current Year	Amount for Previous Year	Amount for Current Year	Amount for Previous Year	Number for Current Year	Number for Previous Year	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Sales of Electricity							1
2	(440) Residential Sales..	$ 16,344,607	$ 16,078,442	185,122	195,077	13,319	13,350	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1).......................	14,948,718	14,227,510	196,965	199,655	5,047	5,007	4
5	Large (or Industrial) (See Instr. 4) (2)...........................	12,660,935	12,031,670	238,233	241,329	7	7	5
6	(444) Public Street and Highway Lighting......................	137,508	128,768	854	797	25	21	6
7	(445) Other Sales to Public Authorities………………….							7
8	(446) Sales to Railroads and Railways..........................							8
9	(448) Interdepartmental Sales..							9
10	TOTAL Sales to Ultimate Consumers.......................	44,091,768*	42,466,391*	621,174 **	636,858	18,398	18,385	10
11	(447) Sales for Resale - Opportunity Non-Firm..............	2,692,053	4,668,925	95,515	167,036			11
12	TOTAL Sales of Electricity...	46,783,821	47,135,316	716,689	803,894	18,398	18,385	12
13	(Less) (449.1) Provision for Rate Refunds.....................	(22,751)						13
14	TOTAL Revenue Net of Provision for Refunds..........	46,761,069	47,135,316					
15	Other Operating Revenues							
16	(450) Forfeited Discounts...							
17	(451) Miscellaneous Service Revenues.........................	88,930	87,179					
18	(453) Sales of Water and Water Power..........................							
19	(454) Rent from Electric Property...................................	1,112,988	1,190,569					
20	(455) Interdepartmental Rents………………………….							
21	(456) Other Electric Revenues.......................................	2,443,883	3,411,789					
22								
23								
24								
25	TOTAL Other Operating Revenues...........................	3,645,801	4,689,537					
26	TOTAL Electric Operating Revenues.........................	$ 50,406,870	$ 51,824,853					

* Includes $205,173 unbilled revenues.

** Includes -1,491 MWH relating to unbilled revenues.

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

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

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the KWH of electricity sold, revenue, average number of customers, average KWH per customer, and average revenue per KWH, excluding data for Sales for Resale which is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	1 - Residential	185,514	$ 16,224,159	13,319	13,929	8.75
3	3 - Residential-Mastered Meterec					
4	84 - Residential-Net Metering					
5	15 - Dusk to Dawn customer Lighting	197	52,324			26.56
6	Residential - Billed	185,711	16,276,483	13,319	13,943	8.76
7	Residential - Unbilled	(589)	85,037	**1		(14.44)
8	Bridger Depr & Boardman Decomm		(16,913)			
9	**Total 440**	185,122	16,344,607	13,319	13,899	8.83
10						
11	442 - Commercial and Industrial Sales:					
12	7 - General Service	17,459	1,684,804	2,427	7,194	9.65
13	9 - General Service	129,820	8,847,232	895	145,050	6.81
14	84 - General Service-Net Metering					
15	15 - Dusk to dawn customer lighting	271	59,498	0		21.95
16	19 - Uniform rate contracts	238,923	12,668,255	7	34,131,857	5.30
17	24 - Irrigation and soil drainage pumping	49,626	4,286,666	1,723	28,802	8.64
18	40 - General Service	11	919	2	5,500	8.35
19	Commercial & Industrial - Billed	436,110	27,547,374	5,054	86,290	6.32
20	Commercial & Industrial - Unbilled	(912)	117,853	**1		(12.92)
21	Bridger Depr & Boardman Decomm		(55,574)			
22	**Total 442**	435,198	27,609,653	5,054	86,110	6.34
23						
24						
25	444 - Public Street and Highway Lighting:					
26	40 - General Service	1	31	1	1,000	3.10
27	41 - Municipal street lighting	822	133,593	17	48,353	16.25
28	42 - Municipal traffic control signal lighting	21	1,797	7	3,000	8.56
29	Public Street & Highway lighting billec	844	135,421	25	33,760	16.05
30	Public St & Highway lighting-unbillec	10	2,283	**1		
31	Bridger Depr & Boardman Decomm		(196)			
32	**Total 444**	854	137,508	25	34,160	16.10
33						
34						
35						
36						
37						
38	Total Billed	622,665	43,886,595	18,398	33,844	7.05
39	Total Unbilled Rev. (See Instr. 6)	(1,491)	205,173	**1		
40	TOTAL	621,174	44,091,768	18,398	33,844	7.05

**1 Number of customers unknown.

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

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

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

Line No.	Sales To (a)	Stat. Class. (b)	Export Across State Lines (c)	FERC Rate Sch. No. (d)	Point of Delivery (State or County) (e)	Station Owner-Ship (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1									
2									
3	Various Utilities								
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

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

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

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

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

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE Demand Charges (m)	Energy (n)	Other Charges (o)	Total (p)	Line No.
							1
							2
				2,692,053		$ 2,692,053	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
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							28
							29

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

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

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

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

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

Line No.	Name of Lessee or Departmen (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Renta	$ 425,320
22			
23	"	Transformer Rentals - Dist	673
24			
25	"	Line Rentals	86,813
26			
27	"	Cogeneration	39,101
28			
29	"	Pole Attachments	145,924
30			
31	"	Facilities Charges	391,492
32			
33	"	Other Rentals	23,665
34			
35	"	Miscellaneous	-
36			
37	"		
38	Total Account 454		$ 1,112,988

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

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

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

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

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

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues	$ 88,930
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 292,854
11	Transmission - Point-to-Point and Other	553,295
12	Photovoltaic Station Service	99
13	DSM Rider Funds	1,593,587
14	Sierra Pacific Usage Charge	837
15	Antelope	2,978
16	Miscellaneous	233
17		
18		
19		
20	Total Account 456	$ 2,443,883
21		
22		
23		

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 56,456	$ 72,882
5	(501) Fuel	$ 5,884,272	5,507,237
6	(502) Steam Expenses	362,224	319,392
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	67,345	102,535
10	(506) Miscellaneous Steam Power Expenses	335,331	419,757
11	(507) Rents	11,483	21,478
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	6,717,111	6,443,281
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	13,336	89,501
16	(511) Maintenance of Structures	30,548	39,698
17	(512) Maintenance of Boiler Plant	551,481	705,427
18	(513) Maintenance of Electric Plant	224,839	313,750
19	(514) Maintenance of Miscellaneous Steam Plant	201,098	279,689
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,021,302	1,428,065
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	7,738,412	7,871,346
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	301,181	233,121
45	(536) Water for Power	314,351	378,267
46	(537) Hydraulic Expenses	511,741	539,589
47	(538) Electric Expenses	56,436	70,763
48	(539) Miscellaneous Hydraulic Power Generation Expenses	106,020	132,863
49	(540) Rents	13,250	9,022
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,302,979	1,363,625

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 12,278	$ 76,052
54	(542) Maintenance of Structures	53,494	74,293
55	(543) Maintenance of Reservoirs, Dams, and Waterways	54,068	67,411
56	(544) Maintenance of Electric Plant	128,915	78,859
57	(545) Maintenance of Miscellaneous Hydraulic Plant	123,614	117,260
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	372,369	413,875
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,675,348	1,777,500
61	Operation		
62	(546) Operation Supervision and Engineering	54,037	35,368
63	(547) Fuel	1,089,881	537,509
64	(548) Generation Expenses	89,337	32,798
65	(549) Miscellaneous Other Power Generation Expenses	16,235	33,606
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,249,490	639,281
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	
70	(552) Maintenance of Structures	8,372	7,741
71	(553) Maintenance of Generating and Electric Plant	4,179	5,126
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	102,134	80,265
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	114,686	93,132
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	1,364,176	732,413
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	8,330,458	7,200,851
77	(556) System Control and Load Dispatching	91	53
78	(557) Other Expenses	795,178	4,007,949
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	9,125,727	11,208,853
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	19,903,663	21,590,112
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	144,450	143,800
84	(561) Load Dispatching	110,431	125,345
85	(562) Station Expenses	95,169	97,328
86	(563) Overhead Line Expenses	26,614	32,271
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	275,373	296,952
89	(566) Miscellaneous Transmission Expenses	7,088	13,308
90	(567) Rents	121,118	141,930
91	TOTAL Operation (Enter Total of lines 83 thru 90)	780,245	850,934
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	19,559	9,536
94	(569) Maintenance of Structures	30,864	18,460
95	(570) Maintenance of Station Equipment	148,813	128,578
96	(571) Maintenance of Overhead Lines	213,689	158,975
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	62	237
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	412,986	315,786
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,193,230	1,166,720
102	Operation		
103	(580) Operation Supervision and Engineering	176,597	160,562

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON		
	If the amount for previous year is not derived from previously reported figures, explain in footnotes.		
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 137,956	$ 146,197
106	(582) Station Expenses	37,507	41,182
107	(583) Overhead Line Expenses	276,566	221,227
108	(584) Underground Line Expenses	29,290	29,040
109	(585) Street Lighting and Signal System Expenses	5,176	5,920
110	(586) Meter Expenses	148,347	95,621
111	(587) Customer Installations Expenses	51,250	89,143
112	(588) Miscellaneous Distribution Expenses	241,084	235,481
113	(589) Rents	21,145	35,612
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,124,918	1,059,985
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	9,612	17,245
117	(591) Maintenance of Structures	-	210
118	(592) Maintenance of Station Equipment	123,775	111,542
119	(593) Maintenance of Overhead Lines	1,136,009	1,055,134
120	(594) Maintenance of Underground Lines	16,389	16,764
121	(595) Maintenance of Line Transformers	16,422	18,215
122	(596) Maintenance of Street Lighting and Signal Systems	26,848	26,871
123	(597) Maintenance of Meters	26,058	10,939
124	(598) Maintenance of Miscellaneous Distribution Plant	42,304	20,614
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,397,417	1,277,534
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,522,335	2,337,519
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	20,637	16,174
130	(902) Meter Reading Expenses	194,024	104,650
131	(903) Customer Records and Collection Expenses	484,600	479,723
132	(904) Uncollectible Accounts	278,900	253,623
133	(905) Miscellaneous Customer Accounts Expenses	21	11
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	978,182	854,181
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	28,981	33,549
138	(908) Customer Assistance Expenses	1,825,126	2,796,583
139	(909) Informational and Instructional Expenses	10,853	3,066
140	(910) Miscellaneous Customer Service and Informational Expenses	29,888	33,749
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	1,894,848	2,866,947
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	3,175,326	3,063,253
152	(921) Office Supplies and Expenses	854,556	718,235
153	(922) Administrative Expenses Transferred-Credit	(1,273,980)	(1,186,640)

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes. Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 233,597	$ 224,731
156	(924) Property Insurance	139,391	135,642
157	(925) Injuries and Damages	322,641	264,890
158	(926) Employee Pensions and Benefits	3,056,715	2,901,784
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	736,844	402,734
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	22,246	25,190
163	(930.2) Miscellaneous General Expenses	181,689	171,091
164	(931) Rents	723	306
165	TOTAL Operation (Enter Total of lines 151 thru 164)	7,449,749	6,721,216
166	Maintenance		
167	(935) Maintenance of General Plant	212,013	194,683
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	7,661,762	6,915,899
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 34,154,022	$ 35,731,378

Line No.	SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 6,717,111	$ 1,021,302	$ 7,738,412
173	Nuclear power			
174	Hydraulic - Conventional	1,302,979	372,369	1,675,348
175	Hydraulic - Pumped Storage			
176	Other power	1,249,490	114,686	1,364,176
	Other Power Supply Expenses	9,125,727	-	9,125,727
177	Total Power Production Expenses	18,395,307	1,508,356	19,903,663
178	Transmission Expenses	780,245	412,986	1,193,230
179	Distribution Expenses	1,124,918	1,397,417	2,522,335
180	Customer Accounts Expenses	978,182	-	978,182
181	Customer Service and Informational Expenses	1,894,848	-	1,894,848
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	7,449,749	212,013	7,661,762
184	Total Electric Operation and Maintenance Expenses	$ 30,623,249	$ 3,530,772	$ 34,154,022

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 304,434		$ 304,434
2	Steam Production Plant	875,301	-		875,301
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	575,034	-		575,034
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	438,832	-		438,832
7	Transmission Plant	730,836	-		730,836
8	Distribution Plant	1,817,077	-		1,817,077
9	General Plant	426,844	-		426,844
10	Depreciation on Disallowed Costs	(12,376)	-		(12,376)
11	Boardman ARO Depreciation	11,723			11,723
12	ARO Accretion	6,868			6,868
13	TOTAL	$ 4,870,139	$ 304,434		$ 5,174,573

B. OTHER AMORTIZATION

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

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			$ (533)
Account 411			
411.6			$ -
411.7			-
411.8			(8,111)
			$ (8,645)

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

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 618,213
3	FUTA	4,220
4	Less: Payroll Deduction and Loading	(655,200)
5	State Taxes:	
6	Ad Valorem	1,059,206
7	Licenses - Hydro Projects	201
8	Regulatory Commission Fees	162,571
9	Franchise Taxes	748,331
10	State Unemployment Taxes	32,767
11	Hydro Generation KWH Tax	72,123
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	$ 2,042,432

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

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

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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 50,406,870
2	Operations and Maintenance Expenses	34,154,022
3	Taxes Other Than Income	2,042,432
4	Regulatory Debits/Credits	(748,954)
5	State Income (Excise) Tax	161,109
6	Interest	3,517,515
7	Federal Income Tax Depreciation	4,863,271
8	Other Line items to Derive Taxable Income	6,868
9	Amortization of Limited-Term Plant	295,788
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 6,114,820
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 2,140,187
30	FIN 48 Adjustment	-
31	Prior Years' Tax Adjustment	(549,507)
32	Total Federal Income Tax Before Other Adjustment	1,590,680
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,411,687
36	Income Tax Adjustments	(8,147,722)
37	Federal Tax on Other Tax Adj @ 35%	(2,357,612)
38		
39	Total Federal Income Tax	$ (766,932)

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

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

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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 50,406,870
2	Operations and Maintenance Expenses	34,154,022
3	Taxes Other Than Income	2,042,432
4	Regulatory Debits/Credits	(748,954)
5	Interest	3,517,515
6	State Income (Excise) Tax Depreciation	4,863,271
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	295,788
	ARO Accretion Expense	6,868
10	Income Tax Adjustments	13,815,791
11	Allowance for AFUDC	(1,411,687)
12	IERCO Taxable Income	(239,457)
13		
14	State Tax Net Income	$ (5,888,717)
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	161,109
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(124,795)
24		
25		
26	Total Oregon State Tax	$ 36,314

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		82,269	0
4	Other Operating (See Note 1)		1,698,181	(4,048,427)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 1,780,450	$ (4,048,427)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 1,780,450	$ (4,048,427)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		4,521	0
	Executive Deferred Compensation Short-Term		188	(2,442)
	Executive Deferred Compensation Long-Term		17,695	(787)
	SFAS 112 - Post Retirement Benefits		13,639	0
	Non-VEBA Pension and Benefits		1,955	(98)
	FAS 123R - Stock Based Compensation		30,692	(45,170)
	Provision for Rate Refunds		0	(347)
	Revenue Sharing		567,896	(263,554)
	Delivery Accruals		101	(101)
	Montana NOL		1,656	(4,732)
	Oregon NOL		5,517	(15,762)
	Federal NOL		0	(1,793,782)
	Valmy Union Pacific Contract		0	(34,510)
	Deferred Idaho ITC		13,264	(333,573)
	VEBA - Post Retiree Benefits		0	(68,158)
	Bridger Revenue Deferral		0	(2,567)
	AFUDC Hells Canyon Relicensing		0	(191,131)
	Reg Liability		616,869	(684,080)
	Reg Asset		245,759	(419,762)
	Boardman Decommission		5,898	0
	Apply DOE Funds to AMI Closed WO's		160,038	(160,038)
	Oregon Pension Expense		12,494	(27,835)
	Total	$	$ 1,698,181	$ (4,048,427)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
12,576	(90,577)						6
							7
							8
$ 12,576	$ (90,577)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 12,576	$ (90,577)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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

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

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

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

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

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

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

4. Use separate pages as required.

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

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)

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

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 3,375,994	$ (379,149)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		3,375,994	(379,149)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 3,375,994	$ (379,149)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

		(c)	(d)
Line 2:			
Depr Federal Adj		3,189,593	(370,442)
Depr Oregon Adj		30,060	(2,817)
Intangible Asset - Labor Deductions		27,817	-
N Valmy Partnership Capitalized Itmes		-	(3,143)
CIAC as Taxable Income		123,445	-
FERC Juris-S Georgia-Acct 282 Def only		-	-
Engineering Fees		125	(2,746)
Software Costs		4,954	-
Total		3,375,994	(379,149)

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

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

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

4. Use separate pages as required.

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

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		4,347,760	(3,400,842)
3				
4	Total Electric.........		4,347,760	(3,400,842)
5				
6				
7	Other (See Note 2).........			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9).........		$ 4,347,760	$ (3,400,842)
11	Classification of Total:			
12	Federal Income Tax.........			
13	State Income Tax.........			
14	Local Income Tax.........			
	Note 1:			
	Oregon PCAM.........		70,252	(40,960)
	FERC Grid West Expense.........		0	(1,278)
	PCA		1,600,227	(872,589)
	Conservation Programs.........		6,772	(143,307)
	Oregon Excess Power Supply Costs.........		512,788	(546,420)
	OATT Revenue Deficiency		0	(6,125)
	Emission Allowances.........		62	(3,653)
	Fixed Cost Adjustment (FCA).........		174,959	(190,809)
	OPUC Grid West Loans.........		0	(217)
	Intervenor Funding Orders.........		656	(1,146)
	Bonus Deferral.........		122	0
	Reorganization Costs.........		0	(3,519)
	Delivery Accruals.........		160	(294)
	REC Sales.........		66,299	(74,974)
	Pension Expense.........		704,602	(648,479)
	LIDAR Surveys Deferral.........		0	(665)
	Bennett Mtn Maintenance Deferral.........		0	(1,143)
	Custom Efficiency Incentive Payment.........		94,780	(2,120)
	Reg Liability.........		419,762	(616,869)
	Reg Asset.........		684,080	(245,759)
	Langley Revenue Deferral.........		12,240	0
	PS&I Costs - Coal & CHP Plants - Write Off.........		0	(517)
	Total.........		4,347,760	(3,400,842)
	Note 2:			
	Advance Coal Royalties.........			
	Oregon Non-Operating Property Tax Adj.........			
	Unrealized Gain/Loss from Rabbi Trust.........			
	Total.........			

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

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

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
(12,906)	-						7
							8
							9
$ (12,906)	$ -		$ -		$ -		10
							11
							12
							13
							14

0	0
(35)	0
(0)	0
(12,871)	0
(12,906)	0

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 506,249	411.4	$ 134,204			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)......	$ 432,382,144	$ 432,382,144				
4	Property Under Capital Leases......						
5	Plant Purchased or Sold......						
6	Completed Construction not Classified......						
7	Experimental Plant Unclassified......						
8	TOTAL (Enter Total of lines 3 thru 7)......	$ 432,382,144	$ 432,382,144				
9	Leased to Others......						
10	Held for Future Use......	$ 89,977	$ 89,977				
11	Construction Work in Progress......	$ 32,477,514	$ 32,477,514				
12	Acquisition Adjustments......						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)......	$ 464,949,635	$ 464,949,635				
14	Accum. Prov. for Depr., Amort., & Depl......	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)......	$ 464,949,635	$ 464,949,635				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation......	NOT AVAILABLE					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights......						
20	Amort. of Underground Storage Land and Land Rights......						
21	Amort. of Other Utility Plant......						
22	TOTAL In Service (Enter total of lines 18 thru 21)......						
23	Leased to Others						
24	Depreciation......						
25	Amortization and Depletion......						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)......						
27	Held for Future Use						
28	Depreciation......						
29	Amortization......						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)......						
31	Abandonment of Leases (Natural Gas)......						
32	Amort. of Plant Acquisition Adj......						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)......						

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	241,023					241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	242,253	0	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	13,839,832	70,696	403			13,910,931	(311)	9
10	(312) Boiler Plant Equipment	40,584,970	973,839	(840,190)			40,718,619	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,866,113	(187,835)	(116,885)			13,561,393	(314)	12
13	(315) Accessory Electric Equipment	4,662,470	(63,472)	(2,405)			4,596,593	(315)	13
14	(316) Misc. Power Plant Equipment	1,774,715	67,068	(130,045)			1,711,738	(316)	14
15	(317) Asset Retirement Costs for Steam Production	4,337,526	(521,588)				3,815,938	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	79,172,236	338,708	(1,089,122)	0	0	78,421,822		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	10,334,723	706,547				11,041,270	(330)	27
28	(331) Structures and Improvements	17,320,425	515,192				17,835,617	(331)	28
29	(332) Reservoirs, Dams, and Waterways	91,287,562	22,305				91,309,867	(332)	29
30	(333) Water Wheels, Turbines, and Generators	22,959,211	10,077				22,969,288	(333)	30
31	(334) Accessory Electric Equipment	6,963,211	901,389				7,864,600	(334)	31
32	(335) Misc. Power Plant Equipment	3,370,098	471,084	(3,162)			3,838,020	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105					1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0					0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	153,623,335	2,626,594	(3,162)		0	156,246,767		35

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plant								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	232,795,571	2,965,302	(1,092,284)	0	0	234,668,589		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,574,835	$ (311)				4,574,524	(350)	48
49	(352) Structures and Improvements	6,106,028	350,386	(1,603)			6,454,811	(352)	49
50	(353) Station Equipment	30,529,149	4,305,983	(75,554)			34,759,578	(353)	50
51	(354) Towers and Fixtures	14,240,505	442,024	(15,032)			14,667,497	(354)	51
52	(355) Poles and Fixtures	17,344,660	3,690,836	(76,026)			20,959,470	(355)	52
53	(356) Overhead Conductors and Devices	15,609,116	3,051,096	(92,650)			18,567,562	(356)	53
54	(357) Underground Conduit	0					0	(357)	54
55	(358) Underground Conductors and Devices	0					0	(358)	55
56	(359) Roads and Trails	53,198	(4,632)				48,566	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	88,457,492	11,835,382	(260,865)	0	0	100,032,009		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	148,192					148,192	(360)	60
61	(361) Structures and Improvements	1,283,228	(71,556)	(148)			1,211,524	(361)	61
62	(362) Station Equipment	7,692,788	(537,019)	(41,287)			7,114,482	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,471,311	320,962	(60,380)			17,731,893	(364)	64
65	(365) Overhead Conductors and Devices	8,108,539	112,218	(71,374)			8,149,383	(365)	65
66	(366) Underground Conduit	698,490	(10,213)	(3,534)			684,743	(366)	66
67	(367) Underground Conductors and Devices	3,193,316	(7,547)	(40,527)			3,145,242	(367)	67
68	(368) Line Transformers	39,103,549	1,879,092	(51,602)			40,931,039	(368)	68
69	(369) Services	2,901,225	856	(38,042)			2,864,039	(369)	69
70	(370) Meters	10,238,020	(3,747,242)	(56,232)			6,434,546	(370)	70
71	(371) Installations on Customer Premises	224,852	8,604	(4,756)			228,700	(371)	71
72	(372) Leased Property on Customer Premises	0					0	(372)	72
73	(373) Street Lighting and Signal Systems	213,150	4,806	(5,274)			212,682	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0					0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	91,276,660	(2,047,039)	(373,156)	0	0	88,856,465		75

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	499,096		(13,988)			485,108	(390)	78
79	(391) Office Furniture and Equipment	44,242	96,017	(3,441)			136,818	(391)	79
80	(392) Transportation Equipment	2,193,640	336,886	(81,962)			2,448,563	(392)	80
81	(393) Stores Equipment	0	4,866				4,866	(393)	81
82	(394) Tools, Shop and Garage Equipment	4,129					4,129	(394)	82
83	(395) Laboratory Equipment	69,153	9,626				78,779	(395)	83
84	(396) Power Operated Equipment	1,527,165					1,527,165	(396)	84
85	(397) Communication Equipment	3,165,604	710,546	(11,314)			3,864,836	(397)	85
86	(398) Miscellaneous Equipment	24,321					24,321	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	7,535,592	1,157,941	(110,705)	0	0	8,582,828		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	7,535,592	1,157,941	(110,705)	0	0	8,582,828		91
92	TOTAL (Accounts 101 and 106)	420,307,569	13,911,586	(1,837,010)	0	0	432,382,144		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 420,307,569	$ 13,911,586	$ (1,837,010)	$	$	$ 432,382,144		96

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

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

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

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

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

Section A. Balances and Changes During Year

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

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

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

MATERIALS AND SUPPLIES

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

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

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 201,915,590	$ 201,915,590				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	201,915,590	201,915,590				
9	Leased to Others						
10	Held for Future Use	$ 267,370	267,370				
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	202,182,960	202,182,960				
14	Accum. Prov. for Depr., Amort., & Depl.	$ 78,661,118	78,661,118				
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 123,521,842	$ 123,521,842				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	$ 77,727,539	$ 77,727,539				
19	Amort and Depl of Producing Natural Gas land and land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant	$ 933,579	933,579				
22	TOTAL In Service (Enter total of lines 18 thru 21)	78,661,118	78,661,118				
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)	$ 78,661,118	$ 78,661,118				

ELECTRIC PLANT IN SERVICE

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

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

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

ELECTRIC PLANT IN SERVICE (Continued)

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 245					$ 234	(301)	2
3	(302) Franchises and Consents	999,187					1,164,443	(302)	3
4	(303) Miscellaneous Intangible Plant	1,477,397					1,283,848	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$ 2,476,829					$ 2,448,526		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights							(310)	8
9	(311) Structures and Improvements							(311)	9
10	(312) Boiler Plant Equipment							(312)	10
11	(313) Engines and Engine Driven Generators							(313)	11
12	(314) Turbogenerator Units							(314)	12
13	(315) Accessory Electric Equipment							(315)	13
14	(316) Misc. Power Plant Equipment							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment							(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	$ 40,573,412					$ 38,011,462		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights							(320)	18
19	(321) Structures and Improvements							(321)	19
20	(322) Reactor Plant Equipment							(322)	20
21	(323) Turbogenerator Units							(323)	21
22	(324) Accessory Electric Equipment							(324)	22
23	(325) Misc. Power Plant Equipment							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights							(330)	27
28	(331) Structures and Improvements							(331)	28
29	(332) Reservoirs, Dams, and Waterways							(332)	29
30	(333) Water Wheels, Turbines, and Generators							(333)	30

ELECTRIC PLANT IN SERVICE

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

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

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

ELECTRIC PLANT IN SERVICE (Continued)

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 34)	$ 30,625,770					$ 28,873,314		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights							(340)	37
38	(341) Structures and Improvements							(341)	38
39	(342) Fuel Holders, Products and Accessories							(342)	39
40	(343) Prime Movers							(343)	40
41	(344) Generators							(344)	41
42	(345) Accessory Electric Equipment							(345)	42
43	(346) Misc. Power Plant Equipment							(346)	43
44	(347) Asset Retirement Costs for Other Production							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 7,466,721					$ 21,944,993		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	78,665,903					88,829,769		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,514,887					1,431,831	(350)	48
49	(352) Structures and Improvements	2,501,457					2,823,425	(352)	49
50	(353) Station Equipment	15,207,233					14,736,411	(353)	50
51	(354) Towers and Fixtures	6,360,063					6,242,124	(354)	51
52	(355) Poles and Fixtures	4,647,552					4,876,460	(355)	52
53	(356) Overhead Conductors and Devices	7,432,536					7,449,474	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	17,824					15,707	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	$ 37,681,552					$ 37,575,431		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	135,436					135,100	(360)	60
61	(361) Structures and Improvements	1,186,872					1,122,872	(361)	61
62	(362) Station Equipment	6,704,195					6,145,688	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,471,311					17,731,892	(364)	64
65	(365) Overhead Conductors and Devices	8,108,538					8,149,382	(365)	65
66	(366) Underground Conduit	698,490					684,743	(366)	66
67	(367) Underground Conductors and Devices	3,193,316					3,145,241	(367)	67
68	(368) Line Transformers	18,029,600					17,534,952	(368)	68
69	(369) Services	2,901,224					2,864,040	(369)	69
70	(370) Meters	2,602,462					2,546,122	(370)	70
71	(371) Installations on Customer Premises	224,852					228,701	(371)	71

ELECTRIC PLANT IN SERVICE

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

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises.......................................							(372)	72
73	(373) Street Lighting and Signal Systems...	213,150					212,682	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant...............................							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)..................	$ 61,469,446					$ 60,501,415		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights..	694,360					662,247	(389)	77
78	(390) Structures and Improvements..	3,658,707					3,847,454	(390)	78
79	(391) Office Furniture and Equipment...	1,746,090					1,758,085	(391)	79
80	(392) Transportation Equipment..	2,625,189					2,665,817	(392)	80
81	(393) Stores Equipment...	68,884					77,144	(393)	81
82	(394) Tools, Shop, and Garage Equipment...	260,676					265,623	(394)	82
83	(395) Laboratory Equipment..	510,860					503,461	(395)	83
84	(396) Power Operated Equipment...	460,498					472,273	(396)	84
85	(397) Communication Equipment..	1,408,396					1,640,405	(397)	85
86	(398) Miscellaneous Equipment..	226,235					230,974	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86).......................................	11,659,895					12,123,483		87
88	(399) Other Tangible Property *...							(399)	88
89	(399.1) Asset Retirement Costs for General Plant.................................							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89).................	11,659,895					12,123,483		90
91	TOTAL (Accounts 101 and 106)..	191,953,625					201,478,623		91
92	(102) Electric Plant Purchased **...								92
93	(Less) (102) Electric Plant Sold **...								93
94	Asset Retirement Obligations (ARO)...	372,953					436,967		94
95	TOTAL Electric Plant in Service..	$ 192,326,578					$ 201,915,590		95

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and charges in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page showing the account distributions of these tentative classifications in columns (c) and (d) including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	4,863,271	4,863,271		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	4,863,271	4,863,271		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)	$ 4,863,271	$ 4,863,271		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$ 21,188,800	$ 21,188,800		
19	Nuclear Production				
20	Hydraulic Production - Conventional	14,732,098	14,732,098		
21	Hydraulic Production - Pumped Storage				
22	Other Production	1,662,877	1,662,877		
23	Transmission	11,518,240	11,518,240		
24	Distribution	23,957,162	23,957,162		
25	General	4,256,004	4,256,004		
26	FAS 143 Adj &/or Disallowed Cost	412,358	412,358		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 77,727,539	$ 77,727,539		

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)..	$ 2,199,546	$ 1,854,438	
2	Fuel Stock Expenses Undistributed (Account 152).........................			
3	Residuals and Extracted Products (Account 153)..........................			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated).......................................			
6	Assigned to - Operations and Maintenance................................			
7	Production Plant (Estimated)...	638,580	639,897	
8	Transmission Plant (Estimated)...	558,355	517,867	
9	Distribution Plant (Estimated)..	560,911	743,261	
10	Assigned to - Other..	51,713	38,942	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)...............	1,809,559	1,939,967	
12	Merchandise (Account 155)..			
13	Other Materials and Supplies (Account 156)..................................			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)..			
15	Stores Expense Undistributed (Account 163)................................	192,644	165,042	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)………………	$ 4,201,749	$ 3,959,446	

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use)		21	Sales to Ultimate Consumers (Includ- ing Interdepartmental Sales)	
3	Steam............ Steam.....................................				
4	Nuclear..		22	Sales for Resale	
5	Hydro-Conventional..		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage..................................	INFORMATION	24	Energy Used by the Company (Excluding Station Use):	INFORMATION
7	Other...				
8	Less Energy for Pumping..............................	NOT	25	Electric Department Only	NOT
9	Net Generation (Enter Total of lines 3 thru 8)..	AVAILABLE	26	Energy Losses:	AVAILABLE
10	Purchases...		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)...		29	Unaccounted for Losses	
13	Out (gross)..		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13)...................		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWH)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17)....................				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18)...............................				

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchase plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be case of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amount of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated)
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	98.19	Tuesday	17	8 AM	60 Min. Int	56,573
34	February	89.30	Monday	6	8 AM	" " "	51,371
35	March	99.34	Friday	2	8 AM	" " "	56,515
36	April	80.30	Monday	23	4 PM	" " "	49,812
37	May	81.40	Monday	21	6 PM	" " "	47,513
38	June	110.45	Thursday	28	8 PM	" " "	60,761
39	July	107.30	Thursday	12	4 PM	" " "	70,538
40	August	118.77	Tuesday	7	6 PM	" " "	70,126
41	September	87.20	Wednesday	5	7 PM	" " "	45,075
42	October	72.56	Tuesday	2	2 PM	" " "	56,258
43	November	93.18	Tuesday	27	8 AM	" " "	57,653
44	December	99.97	Wednesday	19	8 AM	" " "	54,244
45	TOTAL	1,137.96					676,439

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues	$ 410,105	$ 18,504	$ 391,601
2	Nuclear power research expenses (elec.)			
3	Other experimental and general research expenses			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent	405,305	18,287	387,018
7	Other expenses (items of $100 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $100 may be grouped by classes if the number			
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	750,364	33,856	716,508
14				
15	Miscellaneous general management expenses (see detail on page 39)	1,176,968	53,104	1,123,864
16				
17	Memberships and contributions (see detail on page 39)	1,284,149	57,939	1,226,210
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 4,026,891	$ 181,689	$ 3,845,202

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Directors' Fees and Expenses:			
2	Richard Dahl - Fees	$ 81,888	$ 3,695	$ 78,193
3	Richard Reiten - Fees and expenses	26,144	1,180	24,964
4	Christine King-Fees and expenses	77,294	3,487	73,807
5	Thomas Wilford - Fees and expenses	69,428	3,133	66,295
6	Jan Packwood-Fees and expenses	54,750	2,470	52,280
7	Judith Johansen-Fees and expenses	72,526	3,272	69,254
8	Joan Smith - Fees and expenses	77,365	3,491	73,874
9	Gary G Michael - Fees	141,582	6,388	135,194
10	Stephen Allred	70,559	3,184	67,375
11	Robert A Tinstman Fees and expenses	78,828	3,557	75,271
12				
13	SUBTOTAL	750,364	33,856	716,507
14				
15	Miscellaneous General Management Expenses:			
16	Moody's Analytics Inc	30,285	1,366	28,919
17	New York Stock Exchange - Listing service	52,976	2,390	50,586
18	Broadridge Financial Solutions	43,589	1,967	41,622
19	Deutche Bank	35,048	1,581	33,467
20	E Source	35,432	1,599	33,833
21	Rivel Research Group	11,880	536	11,344
22	Stock Based Compensation	576,000	25,989	550,011
23	Thomson Financial/Carson	105,197	4,746	100,451
24	Miscellaneous General Management Expenses:	36,604	1,652	34,952
25	Rate Related Amortization	230,657	10,407	220,250
26	Port of Morrow	5,475	247	5,228
27	PR Newswire	13,825	624	13,201
28	SUBTOTAL	1,176,968	51,737	1,094,945
29				
30	Memberships and Contributions:			
31	Associated Taxpayers of Idaho - Membership	22,000	993	21,007
32	Boston College Center for Corporation	5,000		5,000
33	Chamber of Commerce	123,491	5,572	117,919
34	Corporate Executive Board	42,750	1,929	40,821
35	Idaho Associaton of Commerce and Industry	3,000	135	2,865
36	Idaho Technology Council	10,000	451	9,549
37	Misc Memberships (3)	4,150	187	3,963
38	National Assoc of Directors	5,558	251	5,307
39	National HydroPower Association	28,000	1,263	26,737
40	North American Energy Standard	6,500	293	6,207
41	Northwest Power Pool	131,093	5,915	125,178
42	Pacific NW Utilities-Membership	36,824	1,661	35,163
43	Western Electricity Coordinating Council	837,673	37,795	799,878
44	Western Energy Institute	28,110	1,268	26,842
45	SUBTOTAL	1,284,149	144,899	3,066,582
46				
47	**TOTAL**	$ 3,211,481	$ 230,491	$ (230,491)

OFFICERS

1. Report below the name, title and salary for the year for each executive officer whose sala is $50,000 or more. An "executive officer" of a respondent includes its president, secretar treasurer, and vice president in charge of a principal business unit, division or functic (such as sales, administration or finance) and any other person who performs simila policy making functions

2. If a change was made during the year in the incumbent of any position, show name ar total remuneration of the previous incumbent, and date change in incumbency was ma

3. Utilities which are required to file similar data with the Securities and Exchang Commission, may substitute a copy of item 4 of Regulation S-K identified a

Line No.	Title (a)	Name of Officer (b)	Salary for yea Total	Oregon
1				
2	President and Chief Executive Officer	J LaMont Keer	675,000	30,455
3				
4	Executive VP, Administration Services & CFO……………….......	Darrel T Andersor	420,000	18,950
5				
6	Executive Vice President, Operations.......................................	Dan Minor	385,000	17,371
7				
8	Sr Vice President, General Counsel	Rex Blackburr	300,000	13,536
9				
10	Senior Vice President, Power Supply.......................................	Lisa Grow	260,000	11,731
11				
12	Vice President, Finance and Treasurer	Steven R. Keer	260,000	11,731
13				
14	Vice President, Human Resources & Corp Sevices	Luci McDonald	240,000	10,829
15				
16	Vice President and Chief Information Officer...........................	Dennis Gribble	222,000	10,016
17				
18	Vice President, Customer Operations	Warren Kline	222,000	10,016
19				
20	Vice President, Public Affairs...	Jeffrey Malmer	215,000	9,701
21				
22	Vice President Chief Risk Officer	Lori Smith	215,000	9,701
23				
24	Vice President Engineering and Operations	Vern Porter	202,000	9,114
25				
26	Corporate Controller & Chief Accounting Officer......................	Ken Peterser	190,000	8,573
27				
28	Vice President, Regulatory Affairs..	Gregory Saic	172,500	7,783
29				
30	Corporate Secretary..	Patrick Harringtor	170,000	7,670
31				
32	Vice President, Supply Chain	Naomi Crafton-Shanke	170,000	7,670
33				
34				
35				
36				
37				
38				

POLITICAL ADVERTISING

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
ACTUAL INCENTIVE TAX	426.400	$ 4,313
ALAN OLSEN FOR STATE SENATE	"	1,000
BENEFITS FROM 232016	"	34,257
BLOOMBERG FINANCE LP	"	4,275
BOB NONINI FOR STATE REPRESENT	"	1,000
BOQUIST LEADERSHIP FUND	"	500
BRAD LITTLE FOR IDAHO	"	1,000
BRAD WITT FOR STATE REPRESENTA	"	1,000
BRANDON HIXON FOR STATE REPRES	"	500
BRENNEMAN, JOHN	"	35,086
BRENT CRANE FOR STATE REPRESEN	"	500
BROWN RUDNICK BERLACK ISRAELS	"	69,871
BUSINESS INSTITUTE FOR	"	2,500
CANYON COUNTY REPUBLICANS	"	600
CHAMBER OF COMMERCE	"	3,500
CHRISTY PERRY FOR STATE REPRES	"	2,000
CHUCK WINDER FOR STATE SENATE	"	500
CINDY AGIDIUS FOR STATE REPRES	"	500
CITIZENS FOR JIM THOMPSON	"	300
CITIZENS TO ELECT DENNIS RICHA	"	300
CLARK KAUFFMAN FOR STATE REPRE	"	500
CLIFFORD BAYER FOR STATE REPRE	"	1,000
COMMITTEE TO ELECT GENE WHISNA	"	300
COMMITTEE TO ELECT JASON CONGE	"	300
COMMITTEE TO ELECT JEFF KRUSE	"	500
COMMITTEE TO ELECT JOHN E HUFF	"	300
COMMITTEE TO ELECT MIKE MCLANE	"	300
COMMITTEE TO ELECT WALLY HICKS	"	300
COMMITTEE TO RE-ELECT	"	300
COMMITTEE TO RE-ELECT GREG SMI	"	300
DAN JOHNSON FOR STATE SENATE	"	1,000
DARRELL BOLZ FOR STATE REPRESE	"	500
DEAN CAMERON FOR STATE SENATE	"	500
DOUGLAS HANCEY FOR STATE REPRE	"	1,500
DUMAS,BRETT C	"	563
ED MORSE FOR STATE REPRESENTIV	"	1,000
ELKS REHABILITATION HOSPITAL	"	500
ELLEN ROSENBLUM FOR ATTORNEY G	"	2,000
ERIC ANDERSON FOR STATE REPRES	"	1,500

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description		Account Charged
EXEC INCENTIVE	426.400	$ 139,738
EXEC INCENTIVE FICA	"	2,026
FRANK HENDERSON FOR STATE	"	1,000
FRED GIROD FOR STATE SENATE	"	500
FRED MARTIN FOR STATE SENATE	"	2,000
FRED TILMAN FOR STATE REPRESEN	"	1,000
FRED WOOD FOR STATE REPRESENTA	"	500
FRIENDS OF ANDY OLSON	"	300
FRIENDS OF ARNIE ROBLAN	"	300
FRIENDS OF BILL KENNEMER	"	300
FRIENDS OF BRUCE HANNA	"	1,000
FRIENDS OF DOUG WHITSETT	"	700
FRIENDS OF KATIE EYRE BREWER	"	300
FRIENDS OF KIM THATCHER	"	300
FRIENDS OF MARK HAAS	"	2,000
FRIENDS OF MARK JOHNSON	"	300
FRIENDS OF SHAWN LINDSAY	"	2,300
FRIENDS OF SHERRIE SPRENGER	"	300
FRIENDS OF TIM FREEMAN	"	500
FRIENDS OF TOBIAS READ	"	2,000
FRIENDS OF VIC GILLIAM	"	3,000
FRIENDS OF VICKI BERGER	"	300
GAIL WHITSETT FOR OREGON	"	300
GAYLE BATT FOR STATE REPRESENT	"	500
GRAHAM PATERSON FOR STATE REPR	"	500
HAHN,RICHARD L	"	175,636
HOLMES,SANDRA D	"	50
HOPKINS RODEN CROCKETT HANSEN	"	28,000
HOUSE LEADERSHIP VICTORY FUND	"	1,000
IDAHO COUNCIL ON INDUSTRY	"	500
IDAHO DEMOCRATIC LEGISLATIVE C	"	500
IDAHO FREEDOM FOUNDATION	"	1,000
IDAHO HOUSE REPUBLICAN CAUCUS	"	500
IDAHO LEGISLATIVE ADVISOR	"	350
IDAHO LIABILITY REFORM COALITI	"	1,000
IDAHO MINING ASSOCIATION	"	6,435
IDAHO PETROLEUM COUNCIL	"	2,500
IDAHO PRIOR APPROPRIATION DOCT	"	50,000

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description		Account Charged
IDAHO PROSPERITY FUND	426.400	$ 3,500
IDAHO STATE SOCIETY	"	13,860
IDAHO WATER USERS ASSOCIA	"	1,700
JANET TRUJILLO FOR STATE REPRE	"	500
JASON MONKS FOR STATE REPRESEN	"	500
JEFF BARKER FOR STATE REPRESEN	"	200
JEFF THOMPSON FOR STATE REPRES	"	750
JIM GUTHRIE FOR STATE SENATE	"	2,000
JIM PATRICK FOT STATE SENATE	"	500
JIM RICE FOR STATE SENATE	"	1,500
JOE PALMER FOR STATE REPRESENT	"	1,000
JOHN GOEDDE FOR STATE SENATE	"	1,000
JUDY BOYLE FOR STATE REPRESENT	"	500
JULIE ELLSWORTH FOR STATE REPR	"	1,000
KATHLEEN SIMS FOR STATE REPRES	"	1,000
KATIE EYRE FOR STATE REPRESENT	"	3,000
KELLEY PACKER FOR STATE REPRES	"	1,000
KEN ANDRUS FOR STATE REPRESENT	"	500
KEN ROBERTS FOR STATE REPRESEN	"	500
KEVIN CAMERON FOR OREGON	"	500
LAWERENCE DENNY FOR STATE REPR	"	1,000
LEADERSHIP FUND, THE	"	1,000
LEE HEIDER FOR STATE SENATE	"	500
LENORE BARRETT FOR STATE	"	1,000
LINDEN BATEMAN FOR STATE REPRE	"	500
LITTLE GEM FUND	"	2,500
LOBBY IDAHO, LLC	"	56,717
LUKE MALEK FOR STATE REPRESENT	"	1,500
LYNN M LUKER FOR STATE REPRESE	"	500
MALMEN,JEFFREY L	"	246,886
MARC GIBBS FOR STATE REPRESENT	"	500
MARK PATTERSON FOR STATE REPRE	"	500
MARV HAGEDORN FOR STATE SENATE	"	1,000
MATT WAND FOR EAST COUNTY	"	2,300
MIKE JORGENSON FOR STATE SENAT	"	500
MIKE MOYLE FOR STATE REPRESENT	"	1,000

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description		Account Charged
MIKE SCHAUFLER FOR STATE REP H	426.400	$ 500
MISC CORRECTIONS 2	"	2,768
MISC CORRECTIONS 3	"	2,883
MISC FIX	"	40
MITCH TORYANSKI FOR STATE SENA	"	1,000
NATIONAL HYDROPOWER ASSOC	"	10,000
NEIL ANDERSON FOR STATE REPRES	"	500
NELSON COMMUNICATIONS ASSOC	"	2,400
ONECARD ACCRUAL	"	72,353
OREGONIANS FOR FOOD AND SHELTE	"	1,500
OXLEY & ASSOCIATES INC	"	25,545
PAM STOUT FOR STATE REPRESENTA	"	1,000
PATTI ANNE LODGE FOR	"	1,000
PAUL ROMRELL FOR STATE REPRESE	"	1,000
PAUL SHEPHERD FOR STATE REPRES	"	500
PAYROLL ACCR REVERSAL	"	(67,272)
PAYROLL ACCRUAL	"	62,608
PAYROLL TAX ACCRUAL	"	4,396
PETE NIELSEN FOR STATE REPRESE	"	1,000
QUINN THOMAS PUBLIC AFFAIRS LL	"	119,431
REED DEMORDAUNT FOR STATE REPR	"	500
Reversal-ONECARD ACCRUAL	"	(68,769)
REVERSE CORP EXEC INCENT	"	(2,268)
RICK YOUNGBLOOD FOR STATE REPR	"	1,500
ROBERT ANDERST FOR STATE REPRE	"	1,500
RON MENDIVE FOR STATE REPRESEN	"	1,000
SCOTT BEDKE FOR STATE REPRESEN	"	1,000
SCOTT WORKMAN FOR STATE SENATE	"	1,000
SENATE REPUBLICAN PAC	"	500
SHANNON MCMILLIAN FOR STATE RE	"	500
SHAWN KEOUGH FOR STATE SENATE	"	2,000
SHERYL NUXOLL FOR STATE SENATE	"	500
STEPHEN HARTGEN FOR STATE REPR	"	500
STEVE VICK FOR STATE SENATOR	"	1,000
STEVEN HARRIS FOR STATE REPRES	"	500

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description		Account Charged
STEVEN THAYN FOR STATE SENATE	426.400	$ 1,000
Stock Based Compensation	"	99,770
TERRY GESTRIN FOR STATE REPRES	"	2,000
THOMAS DAYLEY FOR STATE REPRES	"	500
THYRA STEVENSON FOR STATE REPR	"	500
TIM KNOPP FOR STATE SENATE	"	1,700
TODD LAKEY FOR STATE SENATE	"	2,000
TOM LOERTSCHER FOR STATE REPRE	"	1,500
VITO BARBIERI FOR STATE REPRES	"	1,500
WAYNE KRIEGER FOR	"	300
WENDY HORMAN FOR STATE REPRESE	"	500
WIR TELECOM ALLOC CHRG	"	820
WIR TELECOM DIR CHRG	"	919
WIRELESS TEL PR DEDUCT	"	(290)
YMCA - HOMECOURT	"	500
Total Political Contributions		$ 1,256,347

EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest." Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
Idaho Power does not have any expenditures to its affiliated companies			

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP	426.101	$ 210,060	None
IDACORP EMPLOYEES	"	9,940	"
Total Matching Employee Community Service Fund		**220,000**	"
ABERDEEN GEM TRAIL	426.102	500	"
AMERICAN CANCER SOCIETY	"	150	"
AMERICAN CANCER SOCIETY RELAY	"	250	"
AMERICAN HEART ASSOCIATION	"	2,500	"
BOISE COUNTY COMMUNITY JUSTICE	"	250	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"
BOISE RESCUE MISSION	"	1,000	"
BOY SCOUTS OF AMERICA	"	167	"
BOYS AND GIRLS CLUB	"	700	"
BRIGHT TOMORROWS	"	100	"
BURNT RIVER EMS QUICK RESPONSE	"	100	"
CALDWELL CHAMBER OF COMMERCE	"	150	"
CANYON COUNTY FESTIVAL	"	1,881	"
CANYON COUNTY FRATERNAL ORDER	"	200	"
CASA	"	150	"
CASCADE SENIOR CENTER	"	200	"
CHAMBER OF COMMERCE	"	600	"
CHARITABLE ASSISTANCE TO COMMU	"	1,400	"
CHAROLOTTE FIRE RESEED	"	2,500	"
CRISIS CENTER OF MAGIC VALLEY	"	250	"
CYSTIC FIBROSIS FOUNDATION	"	750	"
DESIGNS BY DE	"	1,913	"
DRESS FOR SUCCESS	"	140	"
FESTIVAL OF TREES	"	925	"
GARDEN CITY COMMUNITY CLINIC	"	1,000	"
GARDEN CITY POLICE OFFICER'S A	"	500	"
GEM COUNTY SHERIFF POSSE	"	150	"
GLANBIA CHARITY CHALLENGE	"	250	"
GOLF FOR A CAUSE	"	250	"
HOMAN,WILLIAM B	"	99	"
HUFFMAN,TERESA A	"	71	"
IDACORP EMPLOYEES	"	10,000	"
IDAHO CITY COMMUNITY FUND	"	500	"
IDAHO COMMUNITY FOUNDATION	"	5,000	"
IDAHO FOOD BANK	"	250	"
IDAHO FOODBANK	"	1,750	"
IDAHO RONALD MCDONALD HOUSE	"	2,500	"
KIWANIS CLUB OF NAMPA	"	100	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
MARTIN,FRANCES J	426.102	$ 750	None
MELBA VOLUNTEER FIRE DEPARTMEN	"	500	"
MERIDIAN SENIOR CENTER	"	500	"
MOUNTAIN HOME FIRE DEPARTMENT	"	200	"
NORTH CANYON MEDICAL CENTER	"	100	"
OLMSTEAD,DANIEL H	"	450	"
ONECARD ACCRUAL	"	750	"
ONTARIO DOWNTOWN BUSINESS ASSO	"	75	"
PEARSON,JOSHUA W	"	223	"
POCATELLO ELKS LODGE #674	"	150	"
POCATELLO RELAY FOR LIFE	"	150	"
RED, WHITE AND THE BLUE	"	700	"
Reversal-ONECARD ACCRUAL	"	(750)	"
RIMROCK SENIOR CITIZENS CENTER	"	200	"
ROTARY CLUB OF TWIN FALLS	"	500	"
SAINT ALPHONSUS FOUNDATION	"	350	"
SHOP WITH A COP ASSOCIATION	"	500	"
SHRINER HOSPITALS FOR CHILDREN	"	1,000	"
SILVER SAGE GIRL SCOUT	"	3,000	"
SOUTH CENTRAL COMMUNITY	"	500	"
ST ALPHONSUS FESTIVAL OF TREES	"	6,000	"
ST LUKE'S CHILDRENS HOSPITAL	"	400	"
ST LUKES HEALTH FOUNDATION	"	5,200	"
ST LUKES MCCALL FOUNDATION	"	500	"
STAR OUTREACH NEIGHBORS HELPIN	"	250	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
TOTAL HEALTH & HUMAN SERVICES		**64,893**	
4-H CLUB	426.103	250	"
4-H FFA JUNIOR LIVESTOCK SALE	"	250	"
4-H LIVESTOCK SALE	"	500	"
4-H STATE OFFICE	"	500	"
4-SUMMIT CHALLENGE	"	200	"
ADAMS COUNTY FAIR	"	300	"
AID FOR FRIENDS	"	750	"
AIR FORCE APPRECIATION DAY	"	100	"
AMERICAN FALLS HIGH SCHOOL	"	75	"
AMERICAN FALLS, CITY OF	"	1,500	"
AMERICAN PLANNING ASSOC. IDAHO	"	60	"
ANIMAL SHELTER OF THE WOOD RIV	"	100	"
ASSOC OF OREGON ARCHAEOLOGISTS	"	250	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BAKER COUNTY FAIR - HALFWAY	426.103	$ 3,343	None
BAKER COUNTY SHRINE CLUB	"	250	"
BASQUE MUSEUM AND CULTURAL CEN	"	300	"
BATTELLE ENERGY ALLIANCE	"	500	"
BIG WATER BLOWOUT RIVER FESTIV	"	200	"
BIGGEST SHOW IN IDAHO	"	300	"
BLACKFOOT CHAMBER	"	50	"
BLACKFOOT HIGH SCHOOL	"	100	"
BLACKFOOT RELAY FOR LIFE	"	75	"
BLANKET PROMO ITEM	"	48	"
BOISE ART MUSEUM	"	2,500	"
BOISE BASIN BOOSTERS	"	1,000	"
BOISE BASIN SENIOR CENTER	"	500	"
BOISE CENTENNIAL ROTARY CLUB	"	750	"
BOISE RIDGE RIDERS	"	150	"
BOISE RIVER SWEEP	"	750	"
BOISE SCHOOLS	"	100	"
BOY SCOUTS OF AMERICA	"	417	"
BOYS AND GIRLS CLUB OF WESTERN	"	500	"
BRUNEAU ELEMENTARY SCHOOL	"	200	"
BUHL SENOIR CENTER	"	200	"
CAMBRIDGE RODEO ASSOCIATI	"	100	"
CANYON COUNTY	"	1,000	"
CASCADE MEDICAL CENTER	"	250	"
CASTLEFORD MENS CLUB	"	300	"
CENTURY HIGH SCHOOL GRAD PARTY	"	75	"
CHAMBER OF COMMERCE	"	8,625	"
CHAMBER OF COMMERCE BOISE METR	"	100	"
CITY OF BOISE	"	1,000	"
CITY OF BOISE FIREWORKS DISPLA	"	500	"
CITY OF HANSEN	"	500	"
COOLER PROMO ITEM	"	150	"
DANIEL DOPPS MEMORIAL RODEO AS	"	500	"
DIETRICH, CITY OF	"	100	"
DISTRICT TWO HIGH SCHOOL RODEO	"	200	"
DONNELLY CITY	"	150	"
DONNELLY FIRE DEPARTMENT BURNO	"	500	"
DUCKS UNLIMITED	"	2,500	"
DUDGEON,MELISSA L	"	25	"
EAGLE LIONS CLUB	"	100	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
EDEN SENIOR CENTER	426.103	$ 200	None
EDEN, CITY OF	"	100	"
ELMORE MEDICAL CENTER FOUNDATI	"	250	"
EMMETT OPTIMIST CLUB	"	400	"
FILER SENIOR CENTER	"	200	"
FLASHLIGHT PROMO	"	198	"
FOSDICK GOLF TOURNAMENT	"	400	"
FRIENDS OF THE WEISER RIVER	"	250	"
FRIENDS OF ZOO BOISE	"	2,500	"
FUNDSY	"	2,500	"
FUTURE FARMERS OF AMERICA	"	500	"
GEM STATE KIWANIS	"	500	"
GOD & COUNTY FAMILY FESTIVAL	"	250	"
GOLD DUST RODEO	"	500	"
GOLF BALLS	"	477	"
GOLF TEES	"	43	"
GOOD SAMARITAN HOME	"	500	"
GOODING SENIOR CENTER	"	200	"
GREAT OPEN SPACES CITY MANAGEM	"	500	"
GREATER POCATELLO SENIOR	"	200	"
HAILEY CHAMBER OF COMMERC	"	250	"
HAILEY, CITY OF	"	500	"
HAZELTON, CITY OF	"	100	"
HELLS CANYON DUCKS UNLIMITED	"	200	"
HIGHLAND HIGH SCHOOL GRADUATIO	"	75	"
HORSESHOE BEND CITY	"	400	"
HORSESHOE BEND PARENT TEACHER	"	250	"
HUNTINGTON LIONS CLUB	"	250	"
IDAHO BLACK HISTORY MUSEUM	"	1,000	"
IDAHO BOTANICAL GARDEN	"	3,000	"
IDAHO CANDY COMPANY	"	-	"
IDAHO CHAPTER AMERICAN	"	500	"
IDAHO CHAPTER AMERICAN FI	"	350	"
IDAHO CHAPTER OF THE	"	500	"
IDAHO CITY MANAGERS ASSOCIATIO	"	250	"
IDAHO COMMISSION ON HISPA	"	1,500	"
IDAHO DEPARTMENT OF FISH AND G	"	500	"
IDAHO FOOD BANK	"	1,000	"
IDAHO HORSE RESCUE	"	500	"
IDAHO HUMAN RIGHTS	"	1,000	"
IDAHO HUMANE SOCIETY	"	3,000	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
IDAHO PARTNERS AGAINST DOMESTI	426.103	$ 1,500	None
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO PEACE OFFICERS ASSOCIATI	"	200	"
IDAHO PUBLIC TELEVISION	"	20,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO SENIOR GAMES	"	500	"
IDAHO SNAKE RIVER CHAPTER, AAA	"	200	"
IDAHO STATE HISTORICAL SOCIETY	"	3,000	"
IDAHO TECH CONNECT	"	275	"
IDHO SNAKE RIVER CHAPTER, AAAA	"	-	"
JOE MAMA'S CAR SHOW	"	250	"
JORDAN VALLEY JUNIOR RODEO	"	150	"
JORDAN VALLEY RODEO	"	100	"
KETCHUM WAGON DAYS	"	250	"
KEY TAG	"	34	"
KIMBERLY SENIOR CENTER	"	200	"
KIWANIS CLUB OF EAGLE	"	250	"
KIWANIS CLUB OF ONTARIO	"	250	"
KIWANIS CLUB OF POCATELLO	"	75	"
KNIFE 7 IN 1, S.S.	"	220	"
KUNA YOUTH SOFTBALL & BASEBALL	"	250	"
LIONS CLUB	"	230	"
LIONS CLUB STAR	"	150	"
LIONS CLUB, TWIN FALLS	"	1,000	"
LOWE'S HOME IMPROVEMENT	"	400	"
LOWMAN VOLUNTEER FIRE DISTRICT	"	375	"
LUPO,MARK J	"	1,836	"
MAGIC VALLEY CITIZENS	"	250	"
MAGIC VALLEY REGIONAL	"	2,000	"
MAIN STREET MILE	"	3,000	"
MALHEUR COUNTY JUNIOR LIVESTOC	"	500	"
MCPAWS REGIONAL ANIMAL SHELTER	"	1,000	"
MEADOWS VALLEY COMMUNITY FOUND	"	100	"
MERIDIAN EDUCATION FOUNDATION	"	125	"
MERIDIAN OPTIMIST CLUB	"	100	"
MERIDIAN POLICE DEPARTMENT	"	400	"
MERIDIAN SENIOR CENTER	"	500	"
MERIDIAN YOUTH BASEBALL SOFTBA	"	1,000	"
MERIDIAN, CITY OF	"	750	"
MINIATURE UTILITY TRUCK	"	35	"
MISC CORRECTIONS 2	"	300	"
MISC CORRECTIONS 3	"	312	"
MISC CORRECTIONS 5	"	(625)	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
MOUNTAIN HOME	426.103	$ 150	None
MOUNTAIN HOME LADIES GOLF ASSO	"	100	"
MOUNTAIN HOME OFFICERS SPOUSES	"	200	"
NATIONAL FEDERATION OF THE BLI	"	500	"
NEIGHBORHOOD HOUSING	"	3,800	"
neon highliter with Ipco logo	"	53	"
NO OR MULTIPLE DESC	"	82	"
NORTH BANNOCK COUNTY FAIR	"	160	"
NORTHWEST ALCOHOL CONFERENCE	"	600	"
NORTHWEST CHILDREN'S HOME	"	1,000	"
OAKLEY SENIOR CITZEN CENTER	"	200	"
OAKLEY VIGILANTEES	"	250	"
ONECARD ACCRUAL	"	9	"
ONECARD CORRECTIONS	"	263	"
OWYHEE BUTTER TOFFEE	"	1,936	"
OWYHEE COUNTY FAIR JUNIOR LIVE	"	400	"
OWYHEE COUNTY HORSE 4-H LEADER	"	200	"
PAYETTE COUNTY FAIR	"	400	"
PAYETTE COUNTY RODEO	"	100	"
PEARSON,JOSHUA W	"	212	"
PEREGRINE FUND INC, THE	"	2,500	"
PHETMISAY,TONJA I	"	150	"
PINE SENIOR CENTER	"	50	"
POCATELLO / CHUBBUCK SCHOOL DI	"	1,500	"
POCATELLO AIRPORT APPRECIATION	"	500	"
POCATELLO H.S.	"	75	"
POCATELLO MARATHON	"	1,000	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"
PRO LETTER OPENER	"	57	"
PROM MUG 16 0Z	"	95	"
PROMO SEWING KIT	"	50	"
PROMOTIONAL APPAREL	"	35	"
RICHFIELD SENIOR CENTER	"	200	"
ROTARY CLUB	"	500	"
ROTARY CLUB OF	"	450	"
ROTARY CLUB OF EMMETT	"	250	"
ROTARY CLUB OF NAMPA	"	350	"
ROTARY CLUB OF TWIN FALLS	"	350	"
ROTARY CLUB, BOISE	"	100	"
ROTARY CLUB, BOISE-SUNRIS	"	700	"
ROTARY CLUB, HAILEY	"	500	"
ROTARY DISTRICT 5400	"	63	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
SALMON SENIOR'S GOLF TOURNAMEN	426.103	$ 150	None
SAWTOOTH RANGERS RIDING CLUB	"	250	"
SHEPPARD'S HOME	"	200	"
SHOSHONE SENIOR CENTER	"	200	"
SMART WOMEN, SMART MONEY INC	"	2,500	"
SNAKE RIVER STAMPEDE YOUTH FOU	"	250	"
SOUTHEAST IDAHO SENIOR GAMES	"	500	"
SOUTHERN IDAHO LAND TRUST INC	"	1,250	"
SPACKMAN, BRET	"	201	"
SPORTS BOTTLE - PROMO	"	20	"
ST LUKES MCCALL FOUNDATION	"	250	"
STAR OUTREACH NEIGHBORS HELPIN	"	200	"
STAR, CITY OF	"	500	"
SUPPORTING ALL VOLUNTEER EMERG	"	100	"
TABLE ROCK CHALLENGE	"	400	"
THREE ISLAND DAYS	"	200	"
THURMAN,DOUGLAS K	"	200	"
TIGER OPEN	"	100	"
TRAILING OF THE SHEEP FESTIVAL	"	250	"
TREASURE VALLEY FAMILY YMCA	"	1,500	"
TREASURE VALLEY NAACP	"	1,200	"
TROUT UNLIMITED	"	500	"
TROXEL,JULIE K	"	1,250	"
TWIN FALLS COMMUNITY FOUNDATIO	"	250	"
TWIN FALLS COUNTY FAIR FOUNDAT	"	500	"
TWIN FALLS KIWANIS FOUNDATION	"	250	"
TWIN FALLS OPTIMIST CLUB	"	150	"
TWIN FALLS RAPIDS SOCCER CLUB	"	250	"
TWIN FALLS SENIOR CENTER	"	500	"
UNITED COMMUNITY PARTNERS	"	1,000	"
UNIVERSITY OF IDAHO	"	500	"
WASHINGTON COUNTY FAIR BOARD	"	600	"
WATER BOTTLE PROMO ITEM	"	34	"
WATSON,BLAKE J	"	124	"
WELCOME BACK ORANGE AND BLACK	"	500	"
WENDELL, CITY OF	"	500	"
WEWERS,BRYAN J	"	666	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
YBARGUEN,MICHAEL D	"	113	"
YOUTH LIVESTOCK SALE	"	500	"
TOTAL CIVIC & COMMUNITY		**150,177**	
BASQUE MUSEUM AND CULTURAL CEN	426.104	2,500	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BOISE ART MUSEUM	426.104	$ 1,500	None
BOISE CONTEMPORARY THEATER INC	"	1,000	"
BOISE MUSIC WEEK	"	1,000	"
CHAMBER OF COMMERCE	"	600	"
CHRISTINE DONNELL SCHOOL	"	300	"
COMMUNITY CONCERTS OF	"	250	"
CROSSROADS CARNEGIE ART CENTER	"	300	"
DREXEL H FOUNDATION	"	200	"
FOUR RIVERS CULTURAL CENTER	"	800	"
IDAHO HUMANITIES COUNCIL	"	600	"
IDAHO SHAKESPEARE FESTIVAL	"	2,500	"
IDAHO STATE CIVIC SYMPHONY	"	110	"
IDAHO WATERCOLOR SOCIETY	"	300	"
ION HERITAGE MUSEUM	"	150	"
LONG VALLEY PRESERVATION SOCIE	"	1,500	"
MCCALL ARTS & HUMANITIES COUNC	"	300	"
MERIDIAN ARTS COMMISSION	"	500	"
MERIDIAN SYMPHONY ORCHESTRA	"	750	"
MOUNTAIN HOME HISTORICAL SOCIE	"	300	"
NAMPA PARKS AND RECREATIONS	"	350	"
SUN VALLEY SUMMER SYMPHONY	"	250	"
THE SUN VALLEY BALLET SCHOOL	"	100	"
TOTAL CULTURE & ARTS		**16,160**	
AMERICAN HEART ASSOCIATION	426.106	100	"
BLAZING HOPE YOUTH	"	100	"
BOISE RESCUE MISSION	"	100	"
BOISE STATE PUBLIC RADIO	"	100	"
BOY SCOUTS OF AMERICA	"	900	"
CAPITAL CITY KIWANIS	"	100	"
CARRIBOO CONSERVANCY, INC	"	100	"
CRISIS CENTER OF MAGIC VALLEY	"	100	"
DUCKS UNLIMITED	"	100	"
EAST END PROVIDERS	"	100	"
GIRL SCOUTS OF SILVER SAGE COU	"	100	"
HALFWAY LITTLE LEAGUE	"	100	"
HEADHUNTER BOXING CLUB/USABF	"	100	"
IDAHO HUMANE SOCIETY	"	250	"
IDAHO POWER GUN CLUB	"	100	"
IDAHO SCHOOL FOR THE DEAF AND	"	100	"
IDAHO STATE UNIVERSITY	"	100	"
IDAHO SUNDEVILS	"	100	"
JAPANESE AMERICAN	"	100	"
KUNA AMERICAN LEGION BASEBALL	"	100	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
KUNA HIGH SCHOOL	426.106	$ 100	None
MONROE ELEMENTARY SCHOOL	"	500	"
PAINTFEST-POCATELLO	"	100	"
PAYETTE LAKES SKI PATROL	"	250	"
PODATELLO RELAY FOR LIFE EVENT	"	100	"
ROCK OF HONOR MEMORIAL INC	"	500	"
SALMON SEARCH AND RESCUE	"	100	"
SALMON VOLUNTEER FIRE DEPT	"	100	"
SALMON YOUTH HOCKEY ASSOC	"	100	"
SALVATION ARMY	"	100	"
SIMPLY CATS ADOPTION CENTER	"	100	"
SKYVIEW MARCHING BANK	"	100	"
SNOW SCHOOL AT BOGUS BASIN	"	100	"
TEAM T R U E	"	100	"
TWIN FALLS COUNTY YOUTH BASEBA	"	100	"
TWIN FALLS VENTURE CREW 60	"	100	"
UNIVERSITY OF IDAHO	"	100	"
UPWARD BASKETBALL AND CHEERLEA	"	100	"
VALLEY WIDE REACT TEAM 4956	"	100	"
VENTURING CREW 112	"	100	"
WOMEN'S & CHILDREN'S ALLIANCE	"	100	"
TOTAL VOLUNTEER INVOLVEMENT PROGRAM		**6,000**	
SALVATION ARMY	426.107	41,543	"
TOTAL PROJECT SHARE		**41,543**	
AMERICAN PLANNING ASSOC. IDAHO	426.108	60	"
CHAMBER OF COMMERCE	"	250	"
DUCKS UNLIMITED	"	300	"
IDAHO ASSOCIATION OF SOIL	"	200	"
IDAHO BOWFISHING ASSOCIATION	"	200	"
LAKE CASCADE STATE PARK	"	100	"
MK NATURE CENTER	"	200	"
MOUNTAIN HOME, CITY OF	"	400	"
SOUTHERN IDAHO LAND TRUST INC	"	250	"
TOTAL ENVIRONMENT & CONSERVATION		**1,960**	
IDAHO GOVERNERS CUP	426.109	16,500	"
MARYLHURST UNIVERSITY OFFICE O	"	3,000	"
SMART WOMEN, SMART MONEY INC	"	2,500	"
UNITED WAY OF TREASURY VALLEY	"	3,000	"
UNIVERSITY OF IDAHO	"	2,500	"
TOTAL NON-PROGRAM		**27,500**	
4-H FFA JUNIOR LIVESTOCK SALE	426.110	250	"
4-H LIVESTOCK SALE	"	500	"
4-H MARKET SALE	"	750	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
ABERDEEN DISTINGUISHED YOUNG W	426.11	$ 150	None
AMERICAN FALLS EDUCATION FOUND	"	100	"
BANNOCK COUNTY YOUTH STOCK SAL	"	200	"
BENGAL ATHLETIC BOOSTERS	"	400	"
BOISE SCHOOLS FOUNDATION	"	2,000	"
BOISE STATE UNIVERSITY COBE GO	"	1,000	"
BOISE STATE UNIVERSITY DISCOVE	"	1,500	"
BOMA OF BOISE, INC	"	275	"
BOY SCOUTS OF AMERICA	"	167	"
CALDWELL HIGH SCHOOL ENGINEERI	"	150	"
CANYON COUNTY PARKS / SWIRCD	"	100	"
CANYON COUNTY VANDAL BOOSTER	"	125	"
CANYON RIDGE HIGH SCHOOL SENIO	"	50	"
CASCADE PUBLIC SCHOOLS	"	100	"
CHAMBER OF COMMERCE	"	700	"
COLLEGE OF IDAHO	"	3,000	"
COLLEGE OF SOUTHERN IDAHO	"	3,000	"
COLLEGE OF WESTERN IDAHO	"	4,200	"
COUNCIL SCHOOL DISTRICT	"	1,000	"
COWBOY TRAILS AND TALES, INC	"	95	"
DONNELLY CITY	"	250	"
EAGLE HIGH SCHOOL	"	100	"
EAGLE, CITY OF	"	200	"
FUTURE FARMERS OF AMERICA	"	300	"
GARDEN CITY LIBRARY FOUNDATION	"	500	"
GEM STATE FLY FISHERS	"	200	"
GLENNS FERRY HIGH SCHOOL	"	100	"
GLENNS FERRY PILOT BOOSTER CLU	"	50	"
GOODING HIGH SCHOOL	"	50	"
GRAND VIEW YOUTH NIGHT	"	100	"
GRASSROOT CUTTING HORSE ASSOCI	"	300	"
HUGH O'BRIAN YOUTH LEADERSHIP	"	525	"
IDAHO ACADEMIC DECATHLON	"	1,000	"
IDAHO COUNCIL ON INDUSTRY	"	250	"
IDAHO PROPERTY PROFESSIONALS	"	300	"
IDAHO STATE UNIVERSITY	"	5,625	"
IDAHO TECH CONNECT	"	1,000	"
JALAPENO OPEN	"	250	"
JUNIOR ACHIEVEMENT OF IDAHO	"	1,500	"
LEARNING LAB	"	1,000	"
LOG CABIN LITERARY CENTER	"	1,250	"
MAYORS COMMUNITY SRVC SCHLRSHP	"	500	"
MAYORS YOUTH ADVISORY COUNCIL	"	150	"
MINICO HIGH SCHOOL SENIOR CELE	"	50	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
MOUNTAIN HOME HIGH SCHOOL	426.110	$ 100	None
MOUNTAIN HOME OPTIMIST	"	250	"
NAMPA MAYOR'S TEEN COUNCIL	"	250	"
NEW PLYMOUTH HIGH SCHOOL	"	100	"
NORTHWEST NAZARENE UNIVERSITY	"	5,000	"
NYSSA HIGH SCHOOL	"	100	"
OAKLEY HIGH SCHOOL RODEO TEAM	"	50	"
ORANGE AND BLACK CLASSIC	"	200	"
POWER COUNTY 4 H/FFA LIVE	"	400	"
ROTARY CLUB OF	"	350	"
ROTARY CLUB OF JEROME	"	150	"
ROTARY CLUB, BOISE	"	500	"
SKYVIEW PROJECT GRADUATION	"	100	"
SOCIETY OF WOMEN ENGINEERS	"	2,000	"
ST PAUL'S CATHOLIC SCHOOL	"	250	"
STATE OF IDAHO DEPARTMENT OF E	"	1,000	"
SUMMIT ELEMENTARY SCIENCE CAMP	"	80	"
SWEET MONTOUR ELEMENTARY	"	100	"
TREASURE VALLEY COMMUNITY COLL	"	3,000	"
TWIN FALLS CHAMBER OF COMMERCE	"	300	"
TWIN FALLS SCHOOL DISTRIC	"	250	"
UPPER COUNTRY EDUCATION FOUNDA	"	200	"
VALLIVUE EDUCATION FOUNDATION	"	1,000	"
WASHINGTON COUNTY FAIR BOARD	"	250	"
TOTAL EDUCATION		**51,342**	
BOISE STATE UNIVERSITY	426.111	15,000	"
BRIGHAM YOUNG UNIVERSITY	"	3,000	"
BRIGHAM YOUNG UNIVERSITY FINAN	"	2,000	"
COLLEGE OF IDAHO	"	5,000	"
COLLEGE OF WESTERN IDAHO	"	2,000	"
EASTERN OREON UNIVERSITY	"	2,000	"
IDAHO STATE UNIVERSITY	"	14,000	"
NORTHWEST NAZARENE UNIVERSITY	"	1,000	"
PORTLAND STATE UNIVERSITY	"	2,000	"
U S NAVAL ACADEMY	"	1,000	"
UNIVERSITY OF CHICAGO	"	2,000	"
UNIVERSITY OF IDAHO	"	18,000	"
UNIVERSITY OF MONTANA	"	1,000	"
UNIVERSITY OF PENNSYLVANIA	"	1,000	"
UNIVERSITY OF PORTLAND	"	2,000	"
UNIVERSITY OF SAN FRANCISCO	"	2,000	"
UNIVERSITY OF SOUTHERN CALIFOR	"	1,000	"
UNIVERSITY OF UTAH	"	2,000	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
WASHINGTON STATE UNIVERSITY	426.111	$ 4,000	None
WASHINGTON UNIVERSITY IN ST LO	"	2,000	"
TOTAL SCHOLARSHIP PROGRAM		**82,000**	
BOISE STATE UNIVERSITY	426.112	1,365	"
CARLETON COLLEGE	"	50	"
COLLEGE OF IDAHO	"	3,210	"
DUKE UNIVERSITY	"	300	"
IDAHO STATE UNIVERSITY	"	975	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
OREGON STATE UNIVERSITY	"	1,000	"
SHIMER COLLEGE	"	600	"
TRUSTEES OF THE UNIVERSITY OF	"	300	"
UNIVERSITY OF IDAHO FOUNDATION	"	15,862	"
UNIVERSITY OF TEXAS AT AUSTIN	"	78	"
WASHINGTON STATE UNIVERSITY FO	"	100	"
TOTAL MATCH HIGHER EDUCATION		**25,840**	
11/16 DBL COIL WSH	426.113	2	"
2000 FORD F550 36' VERSALIFT S	"	30	"
2006 FORD F550 36' SERVICE BUC	"	121	"
2006 GMC 3500 1T EX CAB SERV B	"	4	"
ACTUAL INCENTIVE TAX	"	14	"
ALUM WEDGE STIRRUP	"	21	"
APRIL MATERIAL TRANSFER	"	15,500	"
BECK,BRET E	"	97	"
BENEFITS FROM 232016	"	152	"
BLT CRG GALV 3/8X4.5	"	2	"
BLT EYE GALV 5/8X12	"	4	"
BLT MCH GALV 1/2X12	"	3	"
BLT MCH GALV 5/8X12	"	5	"
BLT MCH GALV 5/8X14	"	7	"
BLT UPSET DBL 5/8X18	"	5	"
BRC XARM WOOD 26"	"	16	"
BRKT DUCT SUP 3	"	56	"
CLIP BONDING 5/8 IN	"	1	"
CLP HOT CU 2/0-2/0	"	9	"
CN PG 1 BLT 6-2/0	"	5	"
CORP INCENTIVE	"	65	"
CORP INCENTIVE FICA	"	5	"
DE WDG FLEX 6-2	"	2	"
GAUTHIER,MARC M	"	48	"
HANSEN,DAVID L	"	97	"
INS PIN C NECK 4KV	"	2	"
INS PIN F-NECK 11KV	"	13	"

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
INS SPOOL SEC GRAY	426.113	$ 1	None
JANUARY MATERIAL TRANSFER	"	13,500	"
JOHNS,STEVEN A	"	292	"
MISC CORRECTIONS	"	27	"
NUT MF 3/8 IN	"	1	"
NUT MF 5/8 IN	"	1	"
ORTIZ,BERNABE	"	406	"
PAYROLL ACCR REVERSAL	"	(199)	"
PAYROLL ACCRUAL	"	19	"
PAYROLL TAX ACCRUAL	"	2	"
PIN PTP STL 1X20 IN	"	8	"
PIN STL 8 IN XLONG	"	22	"
POWERS,CALVIN C	"	48	"
REVERSE CORP INCENT FICA	"	(22)	"
SCREW LAG 1/2X4 IN	"	2	"
TIE FMD SIDE F 2/0	"	3	"
TIE FMD TOP F 2/0	"	30	"
TUBING WL PROT 1/2" GRAY	"	3	"
WSHR CRVD 3X3X11/16	"	8	"
WSHR SQ 2 1/4X11/16	"	2	"
XARM WOOD 7'-8"X3-1/4"X4-1/4"	"	43	"
NON_CASH CONTRIBUTIONS		**30,483**	
TOTAL CONTRIBUTIONS Account 426.1		$ 717,897	

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES
AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during th year where the aggregate of all such payments to a recipient was $25,000 or more including fees, re tainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utili services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed Payments to a recipient by two or more companies within a single system under a cost sharing or othe joint arrangement shall be considered a single item for reporting in this schedule and shall be showi in the report of the principal company in the joint arrangement (as measured by gross operating revenues with references thereto in the reports of the other system companies in the joint arrangemer
2. If more convenient, this schedule may be filled out for a group of companies considered as one syster and shown only in the report of the principal company in the system, with references thereto in the report of the other companies

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	ADECCO	Management Services	$ 1,741
2	ADM ASSOCIATES INC	Energy Efficiency Services	8,339
3	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	11,138
4	BANDUCCI WOODARD SCHWARTZMAN P	Management Services	3,947
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	27,663
6	BERGLES LAW LLC	Legal Services	3,896
7	BETHKE LAW PLLC	Legal Services	1,684
8	BRENNEMAN, JOHN	Lobby Services	1,583
9	BROADRIDGE FINANCIAL SOLUTIONS	Management Services	1,993
10	BROWNE CONSULTING	Management Services	1,706
11	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	4,757
12	BULLARD SMITH JERNSTEDT WILSON	Legal Services	4,733
13	BURKE INCORPORATED	Customer Satisfaction Survey	7,914
14	CHARLES RIVER ASSOCIATES INCOR	Rate Case Services	12,182
15	CLEAREDGE PARTNERS INC	Management Services	3,384
16	CRAPO SMITH PLLC	Legal Services	1,423
17	DAVID EVANS AND ASSOCIATES	Consulting Services	3,297
18	DAVIS WRIGHT TREMAINE LLP	Legal Services	44,938
19	DC ENGINEERING, PC	Engineering Services	2,573
20	DELOITTE TAX LLP	Accounting Services	1,535
21	DESERT RESEARCH INSTITUTE	Environmental Services	2,611
22	ENERNOC INC	Energy Efficiency Services	5,302
23	EVERGREEN CONSULTING GROUP, LL	Consulting Services	9,411
24	EXPERIS IT SERVICES US, LLC	Management Services	4,931
25	GALE ENERGY CONSULTING LLC	Management Services	1,624
26	GANNETT FLEMING INC	Management Services	2,029
27	GARTNER GROUP	Management Services	4,323
28	GIVENS PURSLEY LLP	Legal Services	3,902
29	GJORDING & FOUSER, PLLC	Legal Services	4,593
30	GLAHE & ASSOCIATES INC	Environmental Services	1,617
31	GREENBERG TRAURIG LLP	Legal Services	4,992
32	HYQUAL	Environmental Services	8,674
33	INTER-FLUVE, INC.	Environmental Services	3,859
34	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	7,325
35	ISS CORPORATE SERVICES, INC	Management Services	1,534
36	JACO ENVIRONMENTAL INC	Environmental Services	1,612
37	JONES AND SWARTZ PLLC	Legal Services	9,039
38	LOVINGER KAUFMANN LLP	Legal Services	10,051
39	MARKET STRATEGIES INTERNATIONA	Energy Efficiency Services	1,805
40	MCDOWELL RACKNER & GIBSON PC	Legal Services	65,332
41	MIRANDE, MICHAEL	Legal Services	1,860
42	NIELSEN GROUP INC, THE	Consulting Services	11,880
43	PAINE HAMBLEN LLP	Management Services	7,535
44	PARR BROWN GEE & LOVELESS INC	Legal Services	1,477
45	PERKINS COIE LLP	Legal Services	18,138
46	PLATEAU ARCHAEOLOGICAL INVESTI	Environmental Services	1,348
47	PORTLAND ENERGY CONSERVATION,	Environmental Services	5,567

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during th year where the aggregate of all such payments to a recipient was $25,000 or more including fees, re tainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utili services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed Payments to a recipient by two or more companies within a single system under a cost sharing or othe joint arrangement shall be considered a single item for reporting in this schedule and shall be showi in the report of the principal company in the joint arrangement (as measured by gross operating revenues with references thereto in the reports of the other system companies in the joint arrangemer
2. If more convenient, this schedule may be filled out for a group of companies considered as one systei and shown only in the report of the principal company in the system, with references thereto in the report of the other companies

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
48	PROVEN COMPLIANCE SOLUTIONS IN	Management Services	1,933
49	RIVERSIDE TECHNOLOGY INC	Management Services	2,116
50	SALLADAY, G LANCE	Legal Services	1,727
51	SCHWABE WILLIAMSON & WYATT	Legal Services	3,576
52	STOEL RIVES LLP	Legal Services	6,542
53	SULLIVAN & CROMWELL	Legal Services	7,128
54	SYMANTEC CORPORATION	Legal Services	3,823
55	TEKSYSTEMS	Management Services	3,575
56	TETRA TECH INC	Environmental Services	3,558
57	TUERI LLC	Management Services	1,609
58	U S GEOLOGICAL SURVEY	Environmental Services	5,875
59	UNIVERSITY CORPORATION FOR	Cloud Seeding Modeling Services	8,714
60	UNIVERSITY OF ARIZONA	Weather Research & Forecast Services	2,773
61	UNIVERSITY OF IDAHO	Environmental Services	13,245
62	UNIVERSITY OF TENNESSEE	Environmental Services	2,335
63	VAN NESS FELDMAN	Management Services	13,760
64	WATERSHED SCIENCES INC	Cloud Seeding Modeling Services	1,369
65	WEATHER MODIFICATION INC	Cloud Seeding Modeling Services	15,494
66	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	3,003
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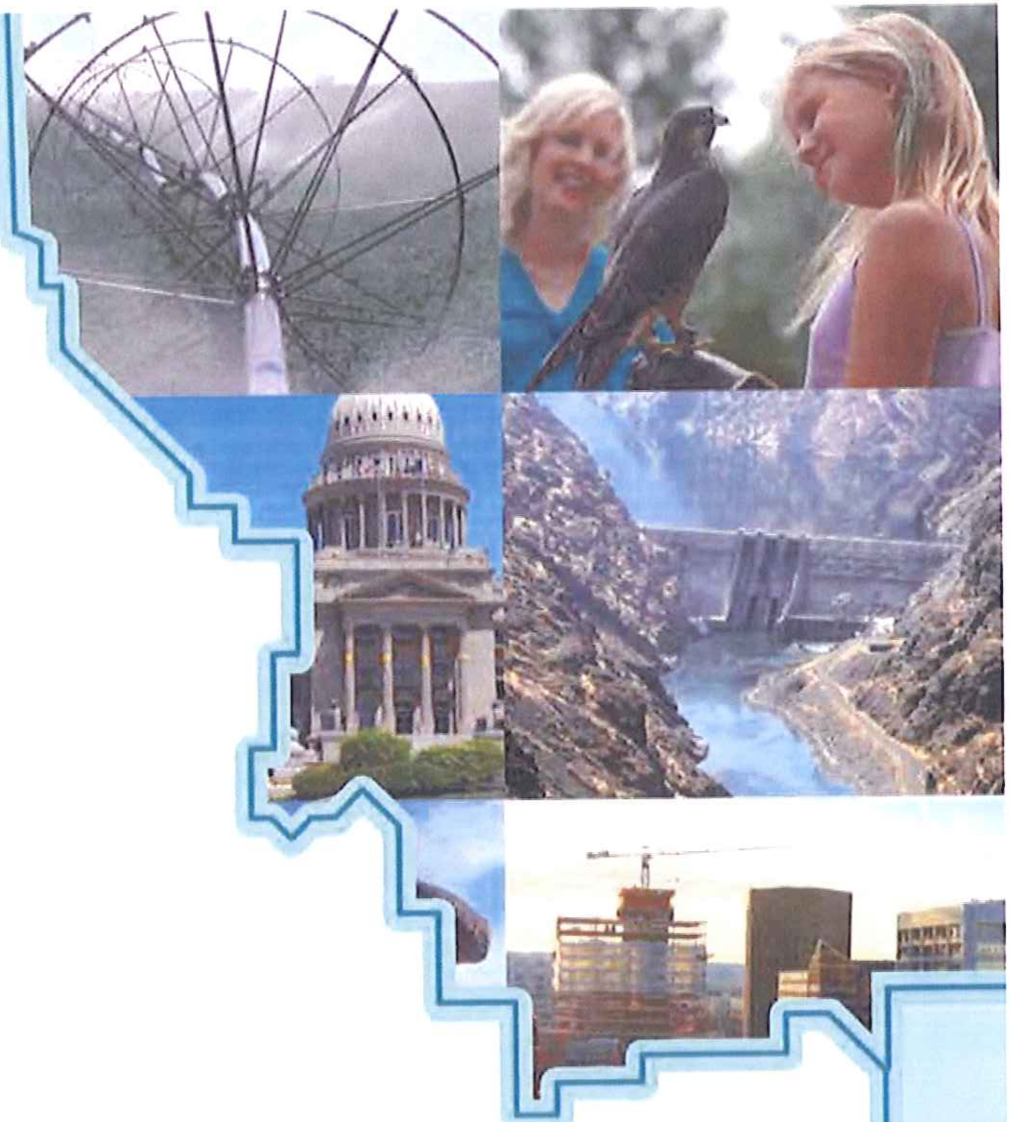
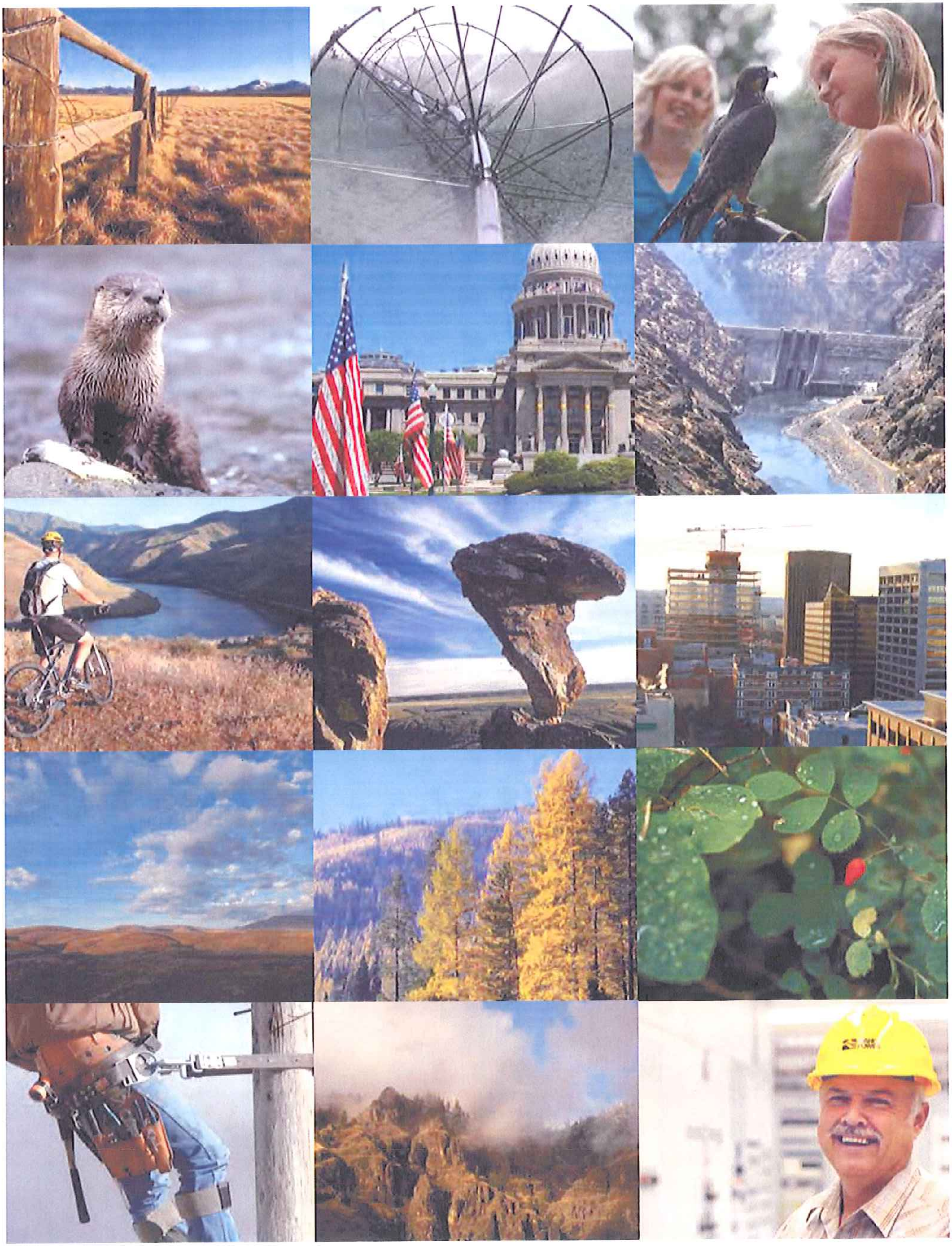
93	**TOTAL**		$ 454,957



2012

IDACORP



To our Shareholders

If you're reading this letter, you likely know that IDACORP is a Boise-based holding company whose primary subsidiary is the regulated electric utility Idaho Power. And that Idaho Power is one of many regulated electric utilities in the United States. So what makes us different?

One key difference is in our three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. In recent years we have focused heavily on advancing this strategy, with excellent results. In the past 12 months in particular, we provided stability during unsettled market conditions by accomplishing earnings, regulatory and operational successes.

In 2012, two especially notable accomplishments helped solidify the already strong operational foundation enjoyed by the company. We saw the ahead of schedule and within budget addition of our newest generation resource, the Langley Gulch Power Plant. This clean, highly efficient, natural gas combined-cycle combustion turbine unit brings more than 300 megawatts of additional generating capacity. In addition to providing electricity for Idaho Power's customers, Langley Gulch helps integrate intermittent resources such as wind and solar from area projects.

Idaho Power also successfully relicensed one of its oldest power plants, the Swan Falls hydroelectric project. In September, the Federal Energy Regulatory Commission granted us a 30-year federal license to continue operating this legacy resource — the first hydroelectric dam built on the Snake River and the nexus of many of our precious water rights.

Another difference is in an effective regulatory strategy that supports our financial performance. In mid-2012, the company began recovering costs and earning a return on the Langley Gulch project immediately following its commercial operation. The reduction of regulatory lag through rate changes and rate mechanisms helped better align retail rates with expenses and investments. Higher power use by irrigators and other customers, as we experienced a warmer, drier spring, also played an important role in our 2012 financial performance.

We achieved last year's financial results without using additional accumulated deferred investment tax credits, or ADITCs, available under a December 2011 settlement agreement with the Idaho Public Utilities Commission and other parties. Under the settlement, Idaho Power will share $21.8 million of benefits with Idaho customers based on 2012 results — the second consecutive year the company has been able to share earnings with customers.

Additionally, we expect minimal use of additional ADITCs during 2013 as we enter the second year of the Idaho settlement agreement. The ADITC-related provisions of the agreement also provide us with an element of earnings stability through 2014 as we continue to execute our strategy.

2012 presented many opportunities for our employees to remain engaged and energized. From across our service area, to our response to Hurricane Sandy, the difference was in Idaho Power's people and the ways they helped move the company forward, always under the thoughtful guidance of the IDACORP Board of Directors.

Our commitment to business excellence was key to IDACORP's ranking among the "40 Best Energy Companies" by *Public Utilities Fortnightly*, a widely-read and well-respected industry publication. The annual survey of power and gas company performance looks at shareholder value in asset-intensive industries. Our inclusion was welcome recognition of our ongoing focus on strategic, value-driven initiatives.

For Idaho Power, the difference is in the collective accomplishments of 2012 that leave us well-positioned to continue to pursue success in 2013 and beyond. We look forward to advancing a number of important initiatives in the next year, including infrastructure projects and new technology solutions, and taking steps to further our dividend policy.

All these elements — those that just happened and those on the horizon — come together to make up a solid, forward-thinking company that will work toward a successful and prosperous 2013.

LaMont Keen

J. LaMont Keen, President & Chief Executive Officer

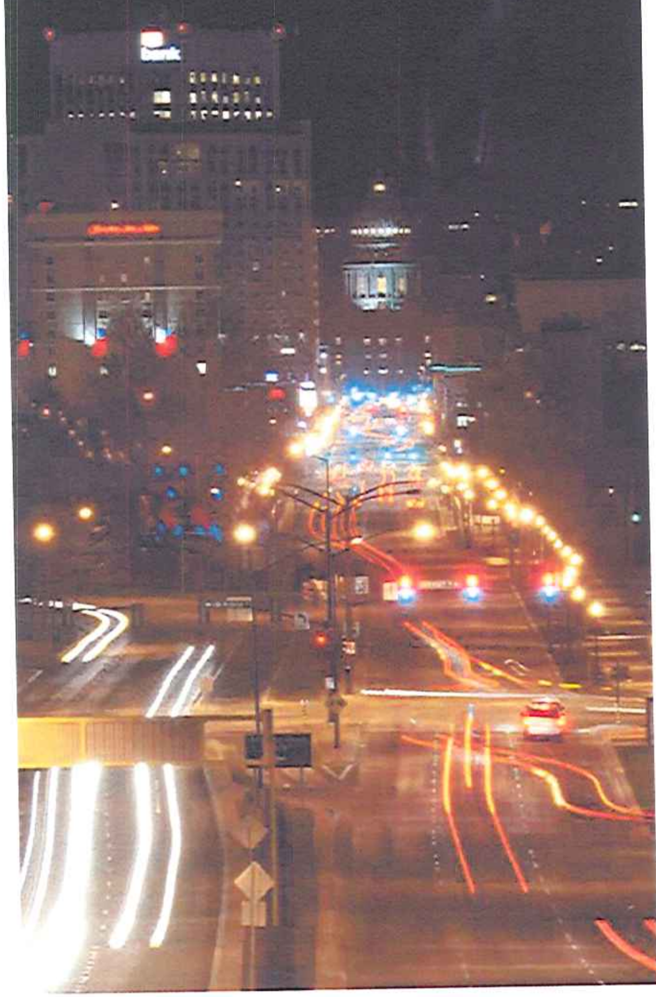
Gary G. Michael

Gary Michael, Chairman of the Board

IDACORP®

2012 HIGHLIGHTS

Thousands of Dollars, Except Per Share Amounts	2012	2011	% Change
Total Operating Revenues	$1,080,662	$1,026,756	5.3
Net Income	$168,761	$166,693	1.2
Earnings Per Diluted Common Share	$3.37	$3.36	0.3
Dividends Paid Per Common Share	$1.37	$1.20	14.2
Total Assets	$5,319,516	$4,960,609	7.2
Number of Employees (full-time)	2,079	2,058	1.0



DILIGENCE

The difference is our diligence

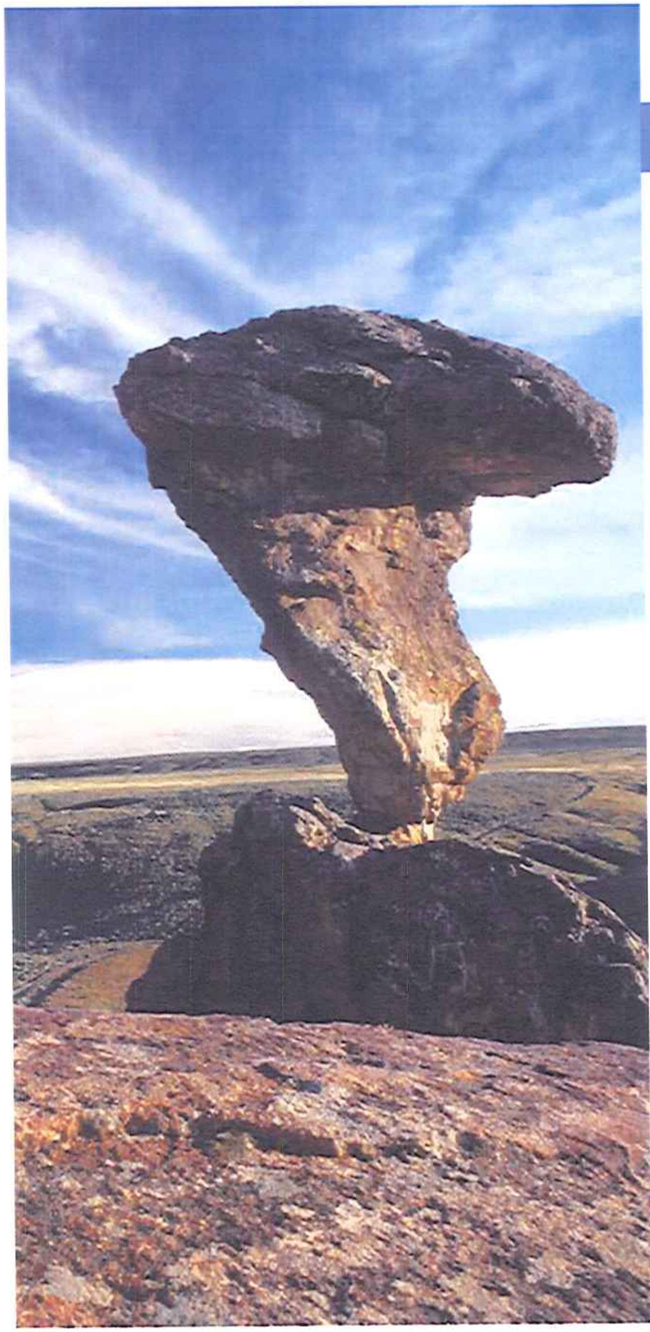
Five years of sustained growth in many areas of our company has created a solid foundation on which IDACORP will build for 2013 and beyond. IDACORP's business strategy emphasizes Idaho Power as the corporation's core business. Idaho Power's effective, innovative three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use benefits shareholders and customers.

Our thoughtful planning seeks to ensure we are poised for continued success, and allows our company the flexibility to take advantage of opportunities when they arise.

We are innovative, and embrace the new paradigms of today's dynamic world, while always standing on our legacy of nearly 100 years. We are ready, responsive and adaptable.

5 years sustained growth

A vibrant downtown Boise lights up at night with restaurants, galleries and other nightlife.



The world famous Balanced Rock south of Buhl, Idaho, stands steady at more than 48 feet tall.

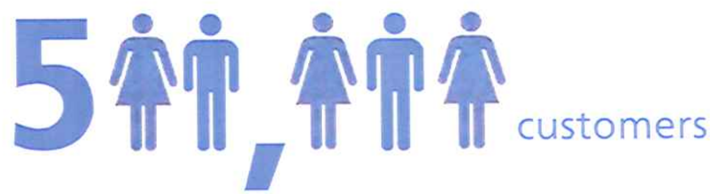
BALANCE

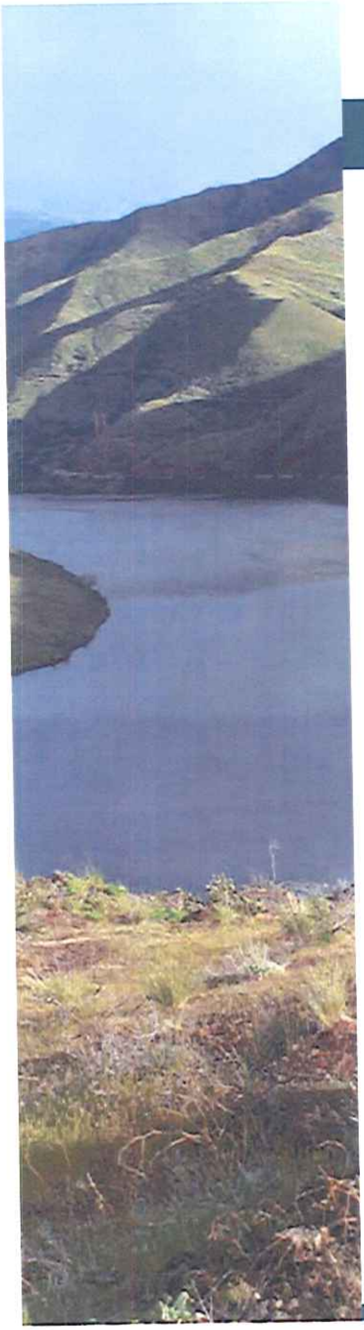
The difference is our balance

Balance is paramount in all we do. At IDACORP, we focus on providing service to our customers while living the mission, vision and values that we believe make us a company of choice for the investment community.

Our primary subsidiary, Idaho Power, provides reliable, responsible, fair-priced energy to more than 500,000 customers, 24/7. It is our privilege and our obligation to always rise to meet the challenge of balancing cost, reliability and environmental concerns in service of our customers.

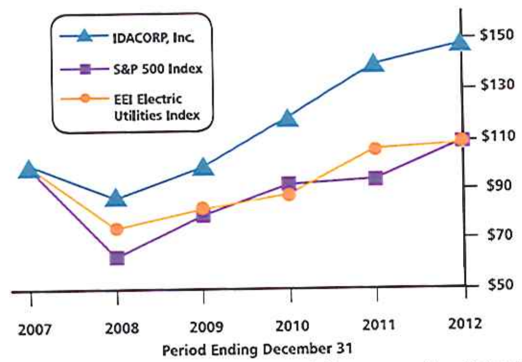
Constructive relationships with stakeholders ensure we fulfill our commitments in a balanced way, now and in the future. Through collaboration with regulators, customers, academia, government, industry and business we are able to successfully execute our business while taking into account diverse interests.





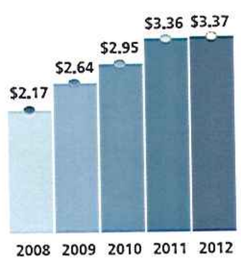
FINANCIAL STRENGTH

Comparison of Cumulative Total Return
$100 Invested December 31, 2007

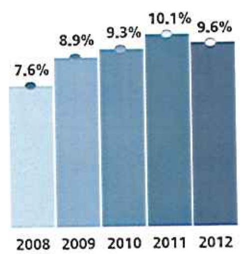


Past performance is not necessarily indicative of future results. These returns were the result of certain market factors and events that may not be replicated in the future.

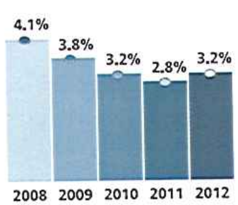
Diluted Earnings Per Share



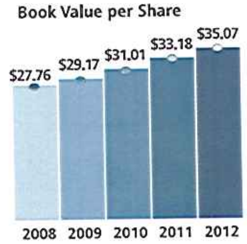
Return on Year-End Equity



Dividend Yield



Book Value per Share



The difference is our financial strength

Earnings

Operating income in 2012 was positively impacted by $65 million due to rate and other regulatory changes, including power cost and fixed cost adjustment mechanisms. Higher sales volumes, driven primarily by a warmer, drier spring in 2012 that caused significant increases in irrigation usage when compared with the prior year, increased operating income by an additional $16 million.

On Feb. 21 we initiated our 2013 full-year IDACORP earnings per share guidance in the range of $3.20 to $3.35 per diluted share.

Sharing

In 2012 Idaho Power achieved earnings above a 10 percent return on year-end equity in the Idaho jurisdiction and therefore will share benefits with our Idaho customers.

Idaho Power did not amortize any additional accumulated deferred investment tax credits, or ADITCs, in 2012. The full $45 million of additional ADITCs originally allocated under a December 2011 settlement agreement with the Idaho Public Utilities Commission (IPUC) and other parties will remain available for potential use in years 2013 and 2014.

According to the agreement, if Idaho Power's return on year-end equity in the Idaho jurisdiction is between 9.5 and 10 percent, there would not be any use of tax credits or any sharing. For earnings between 10 and 10.5 percent, the sharing is equal; 50 percent to the customer, 50 percent to the company. For earnings over 10.5 percent, the sharing is 75 percent to the customer and 25 percent to the company.

Under the agreement, Idaho Power will share $21.8 million of benefits with Idaho customers based on 2012 results — the second consecutive year the company has been able to share earnings with customers.

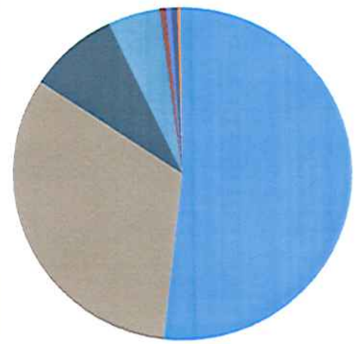
Dividends

IDACORP's Board of Directors reviews the dividend rate on a regular basis to determine its appropriateness in light of a number of factors described in IDACORP's SEC filings. IDACORP's total change in the quarterly dividend rate during 2012 was nearly 27 percent, from $0.30 to $0.38 per share. This increase was consistent with the goal of advancing the dividend policy adopted in late 2011.

These actions moved the dividend closer to the Board of Directors' long-term target of between 50 and 60 percent of sustainable IDACORP earnings. To that end, based on IDACORP's Feb. 21 estimates for earnings and cash flow and assuming the company meets those estimates, management anticipates recommending to the Board an additional increase to the quarterly dividend of at least 10 percent in September 2013.

RESOURCES

2012 Resource Portfolio Mix



* Because Idaho Power sells (or does not own) the renewable energy certificates or "green tags" associated with certain projects in its resource portfolio, using the proceeds to benefit customers, we are not permitted to say the electricity from those projects is delivered to customers.

Hells Canyon Dam is the third, last and arguably most scenic project in the Hells Canyon Complex. With a generating capacity of 391.5 MW, it is the second largest hydroelectric generation resource in our entire fleet.

The difference is our resources

Hydroelectric Generation

For nearly a century Idaho Power has been committed to clean energy. We maintain that promise by vigorously preserving the legacy of our hydro base.

In 2012, hydroelectric generation comprised 57 percent of Idaho Power's total system generation, compared to 69 percent during 2011. As of Feb. 21, 2013, Idaho Power expects hydroelectric generation during 2013 to be in the range of 6.0 to 8.0 million megawatt-hours (MWh), compared to 8.0 million MWh in 2012 and 10.9 million MWh in 2011. Median annual hydroelectric generation is 8.6 million MWh.

When hydroelectric generation is reduced Idaho Power must rely on more expensive generation sources and purchased power; however, most of the increase in power supply costs is eventually collected from customers through power cost adjustment (PCA) mechanisms. Conversely, in periods of greater hydroelectric generation most of the resulting decrease in power supply costs that typically occurs is returned to customers through those PCA mechanisms.

Langley Gulch Power Plant

On June 29, the Langley Gulch Power Plant was substantially complete and placed into commercial operation, ahead of schedule and within budget. The clean, highly-efficient natural gas combined-cycle combustion turbine power plant brings our system additional generating capacity of more than 300 megawatts (MW). It immediately began helping satisfy extremely high electricity demand during the triple-digit heat the week of July 9, including a new record system peak on July 12.

In addition to providing electricity for Idaho Power's customers, Langley Gulch helps integrate intermittent resources such as wind and solar from area projects.

Transmission Projects

Idaho Power continues to focus on expansion of its transmission system in an effort to improve system reliability and to meet the needs of our customers. In 2012 we entered into cost-sharing arrangements with third parties for the permitting phases of two 500-kilovolt transmission projects in which we are engaged, the 1,150-mile Gateway West project, and the 300-mile Boardman to Hemingway project. Idaho Power also continues to work closely with the Federal Rapid Response Transmission Team and state and federal permitting agencies on both projects.

The next major milestone for the Gateway West project in the federal permitting process will be the final Environmental Impact Statement, currently expected in 2013. We anticipate a draft Environmental Impact Statement on Boardman to Hemingway by summer 2013.

Granting of this new license is an important event for our company both symbolically and practically as we look forward to our second century of providing clean, reliable, low-cost power from our fleet of hydroelectric facilities.

Swan Falls Relicensing

Another important operational milestone in 2012 was Idaho Power's receipt of a 30-year federal license from the Federal Energy Regulatory Commission, or FERC, to continue operating our Swan Falls power plant located on the Snake River about 40 miles south of Boise. Swan Falls was the first hydroelectric dam on the Snake River, built in 1901 to supply power to nearby mines. It became Idaho Power's original generation resource when the company that became Idaho Power was formed in 1916. Though it is not the largest hydroelectric plant in our fleet, it is significant as the nexus of many of our precious water rights on the Snake River.

Granting of this new license is an important event for our company both symbolically and practically as we look forward to our second century of providing clean, reliable low-cost power from our fleet of hydroelectric facilities.

PURPA

For nearly a century Idaho Power has been committed to clean energy. Today approximately half of the energy in our portfolio is generated from hydro, wind, solar, biomass and geothermal resources.* We are proud of our relatively small carbon footprint and history of responsible energy generation. We believe renewable energy resources have a place in our generation portfolio. However, over the past few years, renewable energy projects, especially wind projects, which traditionally have qualified for high rates under the Public Utility Regulatory Policies Act, or PURPA, have put an undue burden on the company and our customers.

On Dec. 18, 2012, the IPUC issued its long-awaited order in a broad case addressing alternative-energy projects qualifying under PURPA. The decision culminated more than two years of work on the part of the IPUC, Idaho Power, developers and others.

We believe that the IPUC's decision is, on balance, favorable to Idaho Power customers. In its ruling, the IPUC adopted the company's proposed pricing structure for PURPA wind and solar projects, and maintained the eligibility cap of 100 kilowatts (kW) for wind and solar projects. The IPUC rejected a proposal to apply this pricing structure, based on the company's long-range Integrated Resource Plan (IRP), to non-wind or solar projects of less than 10 average MW. The effect of these rulings is a greatly reduced price for highly intermittent resources such as wind and solar for any new PURPA contracts.

In addition, the IPUC adopted what is in effect a modified "needs" test. New PURPA contracts will be paid for capacity based on the project's ability to deliver during peak hours and when a utility's long-term plan shows the utility is capacity deficient.

Coal Resources Evaluation

We conducted a coal unit environmental investment study during 2012 and 2013 and filed it with the Idaho and Oregon public utility commissions in February 2013 as part of the company's update to the 2011 IRP. The study, which included analysis from Idaho Power and a third-party consultant, shows that keeping coal-fired power plants in the utility's long-range plan is economically preferable to other options despite anticipated expenses for stricter environmental controls.

The purpose of the study was to examine the potential operating costs for the Valmy and Jim Bridger plants going forward based on anticipated environmental regulations and other factors, versus the cost of replacing the generation from those resources. In 2012, Valmy generated 622,666 MWh and Jim Bridger generated 4,374,213 MWh, accounting for roughly 36 percent of the electricity generated by Idaho Power. All of our jointly-owned facilities currently meet or exceed state and federal environmental standards. We will work with our joint owners to help ensure the plants remain compliant.

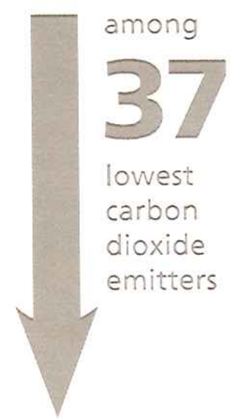
For now, we believe the key is to remain flexible; that will allow us to respond to future requirements if, or when, they are implemented.

Emissions

Idaho Power works hard, and will continue to work hard, to be a responsible steward of the environment and natural resources. As with all of our decisions, environmental decisions are evaluated and balanced with consideration of the impact of those decisions on cost to customers and our ability to reliably serve them.

In 2009, Idaho Power established a goal to reduce its resource portfolio's average CO_2 emission intensity for 2010 through 2013 to a level of 10 to 15 percent below its 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh. To date, we are on track to exceed this goal, and recently extended our commitment to CO_2 reduction through the entire 2010 through 2015 period; we continue to evaluate ways to further reduce our carbon intensity. These emissions reductions were not the result of regulatory requirements, but a voluntary response to shareholder input.

As of 2010, Idaho Power was ranked among the 37 lowest carbon dioxide emitters among the nation's 100 largest electricity producers.



* Because Idaho Power sells (or does not own) the renewable energy certificates or "green tags" associated with certain projects in its resource portfolio, using the proceeds to benefit customers, Idaho Power does not state that the electricity from those projects is delivered to customers.

STRATEGY

The difference is our purposeful regulatory strategy

Idaho Power's 2012 execution of its purposeful regulatory strategy resulted in rates that are fair and more current with expenses, improving the operating strength of the company.

The company received the IPUC's approval to implement a $34 million general rate increase in Idaho on Jan. 1, 2012.

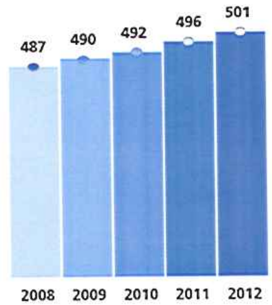
Five months later, on June 29, Idaho Power received an order from the IPUC approving our application to recover the investments we made to construct and integrate the Langley Gulch Power Plant into our operating system. The order approved a $58 million increase in annual Idaho jurisdiction base rates effective July 1, 2012, and represented a $336 million increase in Idaho rate base. We requested and received the effective date of July 1 to coincide with the plant's availability to serve summer peak loads in July.

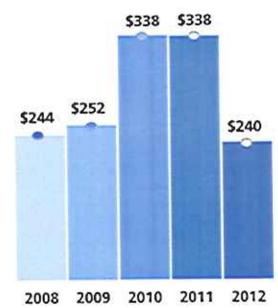
On Sept. 20, the Public Utility Commission of Oregon issued an order approving an approximately $3 million increase in annual base rates for recovery of the Oregon jurisdictional investment in Langley Gulch. New Oregon rates became effective Oct. 1, 2012.

The end of 2012 brought a series of pro-customer filings. These proposals, requesting temporary suspension of two demand response programs and an increase in the net metering cap and pricing adjustments, together with the PURPA order issued in late 2012, addressed fairness and customer rates.

Idaho's majestic state capitol building is constructed almost entirely of locally-sourced sandstone. It is the only geothermally-heated capitol building in the United States.

GROWTH





On June 29, the Langley Gulch Power Plant was substantially complete and placed into commercial operation, ahead of schedule and within budget.

The difference is our economic development and load growth

Idaho Power is a key part of the economy in southern Idaho and eastern Oregon. We are strategic about our pursuit of new customers, effectively shaping loads and contracts and inviting in new business that adds vibrancy to the economy.

Increased Load and Customer Counts

Idaho Power has tiered rates and seasonal rates, which contribute to increased revenues during higher load periods, most notably the third quarter of each year when customer demand is typically at its peak. On July 12, 2012, Idaho Power achieved a record load demand of 3,245 MW, besting the previous record load demand of 3,214 MW set on June 30, 2008.

Idaho Power's low energy prices continue to make our service area an attractive location for business and residential customers.

During October we passed the 500,000 mark for customers connected to our system. Even with the economy still in a position of recovery, our general business customer count increased by 5,534 from the fourth quarter of 2011 to the fourth quarter of 2012, compared with increases of 3,497, and 2,146 in the last two years' fourth quarter, respectively. We view this as a positive trend.

Business Expansion

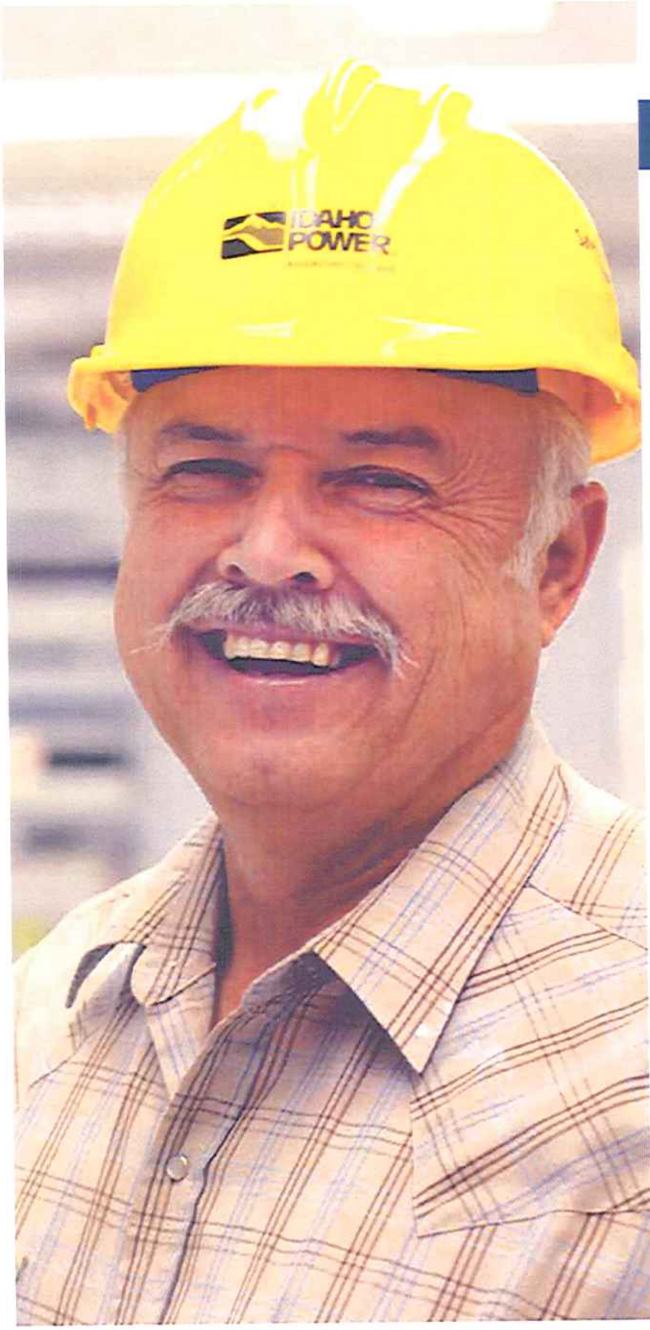
2012 also saw expansion in a variety of industries across our 24,000-square-mile service area, with infrastructure and accompanying jobs coming online in good numbers.

In Boise, two multimillion-dollar downtown construction projects are well underway, and the Lactalis American Group announced a $40 million expansion of its mozzarella cheese plant nearby. Chobani Yogurt completed its major new Twin Falls plant and already employs more than 400 people. In Pocatello, Allstate Insurance currently employs about 250 people and is on track to add 120 more during the first quarter of this year. And recently, that company announced it will be hiring approximately 225 employees specifically to handle roadside emergency calls for customers throughout the U.S.

At the end of September 2012, CNBC identified Idaho as America's most improved state for business. The report cited the state as having extremely low costs, a great workforce and a business-friendly regulatory climate. We view this as positive news as we endeavor to attract companies to our service area and grow our customer base.

On July 12, 2012, Idaho Power achieved a record load demand of **3,245 megawatts**

EMPLOYEES



Idaho Power employees work diligently and safely to ensure reliable service to our more than 500,000 customers.

The difference is our employees

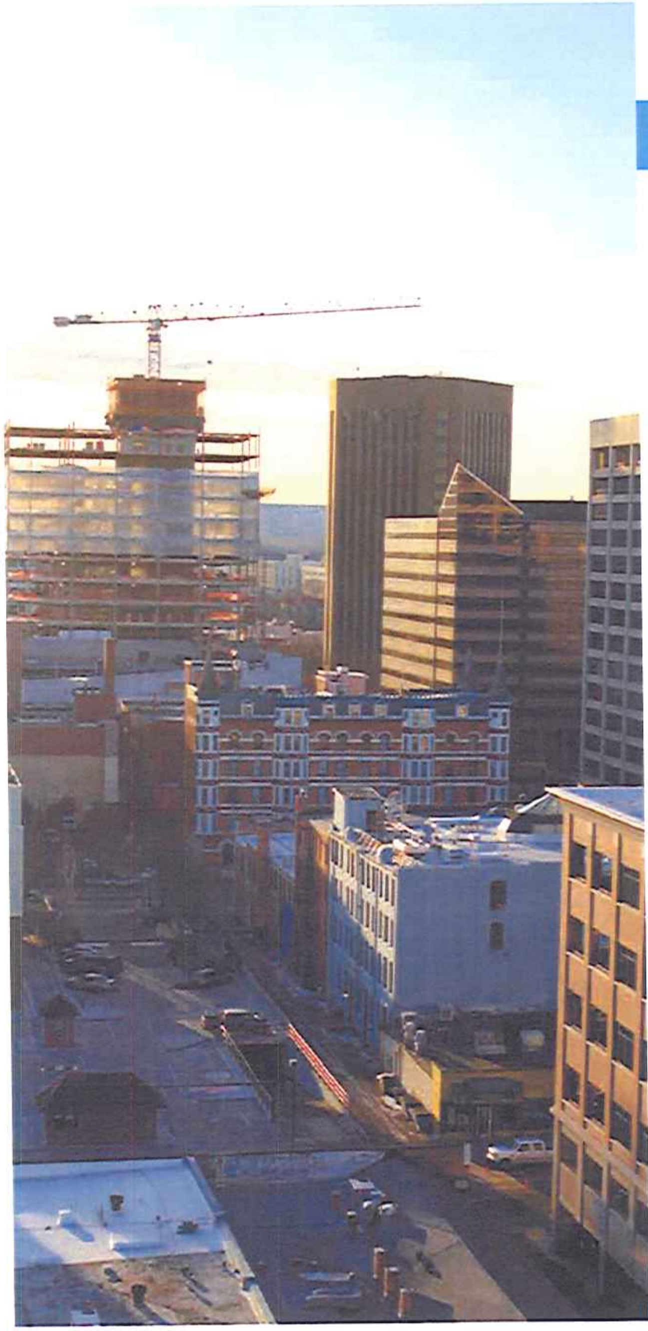
IDACORP is the sum of our great employees. From customer service experts who answer inquiries on a vast number of topics, to generation specialists who keep our resources running, to grid operators who ensure our system is in balance 24/7, the people who work for IDACORP are some of the best in the business.

One shining and unique example of our employee commitment in 2012 was when Idaho Power crews and nearly a dozen trucks left the morning of Nov. 5 to help Long Island Power Authority (LIPA) in New York restore power to the hundreds of thousands of customers affected by Hurricane Sandy. Our crews were deployed to some of the areas hardest hit by the storm, and began working alongside LIPA crews just as a strong nor'easter rolled in.

The convoy of Idaho Power trucks (above) drove three days and more than 2,500 miles to the town of Old Bethpage, New York.

Long Island residents impacted by Hurricane Sandy expressed thanks to Idaho Power crews who helped restore their power. Assistance with the catastrophe back East was a clear demonstration of our company's commitment to serving our communities, near and far.

IDACORP is the sum of our great employees.



CONNECTION

The difference is our connection

At IDACORP we look forward to continuing our nearly 100-year tradition of carefully guiding a financially strong, stable company to connect with the needs of our customers and investors. Our three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies is our guiding compass. It has served us admirably in the past and will be key in accomplishing future goals.

We thank our owners for their continued investment in IDACORP and, by extension, Idaho Power. We look forward to working toward a successful and prosperous 2013 for the innovative forward-thinking company that belongs to all of us.

nearly
100 Years
of tradition

A tower crane atop a quickly-rising skyscraper shows how Idaho continues to grow and prosper.

IDACORP and Idaho Power Officers

IDACORP and Idaho Power

J. LaMont Keen (38)
President and Chief Executive Officer, IDACORP, Inc. and Chief Executive Officer, Idaho Power

Darrel T. Anderson (17)
Executive Vice President – Administrative Services and Chief Financial Officer, IDACORP, Inc. and President and Chief Financial Officer, Idaho Power

Rex Blackburn (5)
Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power

Patrick A. Harrington (27)
Corporate Secretary, IDACORP, Inc. and Idaho Power

Steven R. Keen (30)
Vice President, Finance and Treasurer, IDACORP, Inc. and Senior Vice President – Finance and Treasurer, Idaho Power

Jeffrey Malmen (5)
Vice President, Public Affairs, IDACORP, Inc. and Idaho Power

Daniel B. Minor (27)
Executive Vice President, IDACORP, Inc. and Executive Vice President and Chief Operating Officer, Idaho Power

Ken W. Petersen (14)
Corporate Controller and Chief Accounting Officer, IDACORP, Inc. and Idaho Power

Lori D. Smith (29)
Vice President and Chief Risk Officer, IDACORP, Inc. and Idaho Power

Idaho Power

Dennis C. Gribble (34)
Vice President and Chief Information Officer

Lisa A. Grow (25)
Senior Vice President, Power Supply

Warren Kline (39)
Vice President, Customer Operations

Luci K. McDonald (8)
Vice President, Human Resources and Corporate Services

N. Vern Porter (23)
Vice President, Delivery Engineering and Construction

Gregory W. Said (32)
Vice President, Regulatory Affairs

Naomi Shankel (12)
Vice President, Supply Chain

( ) years of service

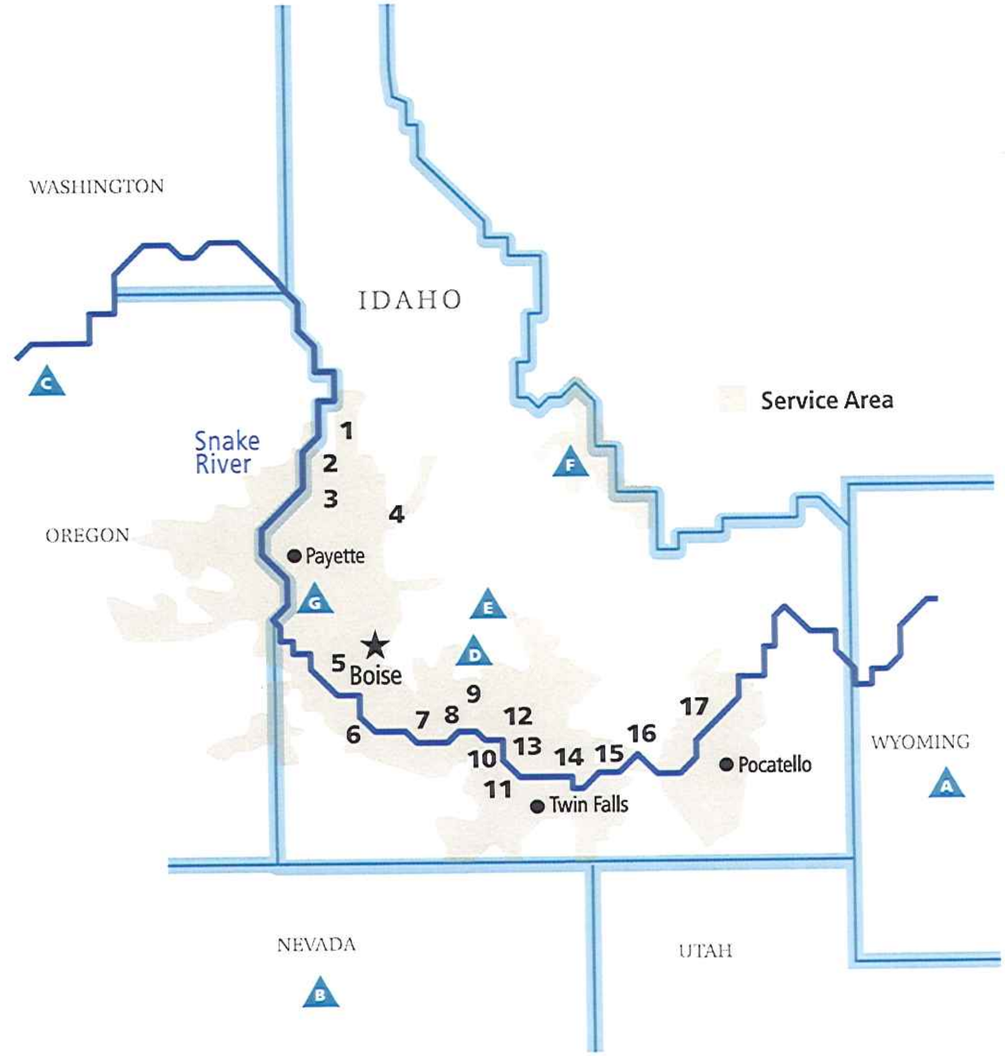
Hydroelectric Facilities & Nameplate Capacities

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	585,400 kW
4	Cascade	12,420 kW
5	Swan Falls	27,170 kW
6	C.J. Strike	82,800 kW
7	Bliss	75,000 kW
8	Lower Malad	13,500 kW
9	Upper Malad	8,270 kW
10	Lower Salmon	60,000 kW
11	Upper Salmon	34,500 kW
12	Thousand Springs	8,800 kW
13	Clear Lake	2,500 kW
14	Shoshone Falls	12,500 kW
15	Twin Falls	52,897 kW
16	Milner	59,448 kW
17	American Falls	92,340 kW

Thermal Facilities

A	Jim Bridger	770,501 kW[1]
B	North Valmy	283,500 kW[1]
C	Boardman	64,200 kW[1]
D	Evander Andrews	270,900 kW[2]
E	Bennett Mountain	172,800 kW
F	Salmon Diesel	5,000 kW
G	Langley Gulch	318,452 kW

[1] Idaho Power share
[2] Danskin



We are innovative, and embrace the new paradigms of today's dynamic world, while always standing on our legacy of nearly 100 years. We are ready, responsive and adaptable.

REFERENCES

Dividend Payment Dates

For IDACORP, Inc. Common Stock quarterly on or about the 28th of February, and the 30th of May, August and November.

Transfer Agents/Registrar

For IDACORP, Inc. Common Stock
Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
1-800-565-7890

Common Stock Information

Ticker symbol: IDA
Listed: New York Stock Exchange, 20 Broad St.
New York, New York 10005

Contact

Broker/Analyst Contact: Lawrence F. Spencer
Director of Investor Relations
208-388-2664 Fax: 208-388-6916
Email: lspencer@idacorpinc.com

Shareowner Contact: 1-800-635-5406 Fax: 208-388-6955
Email: cshepard@idahopower.com
or barbsmith@idahopower.com

Corporate Headquarters

Mailing: P.O. Box 70, Boise, Idaho 83707-0070
Street: 1221 W. Idaho St., Boise, Idaho 83702-5627
Phone: 208-388-2200
Website: www.idacorpinc.com

SEC Form 10-K

The IDACORP, Inc. and Idaho Power Company combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders also are available on our website at www.idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

2013 Annual Meeting

The 2013 Annual Meeting of Shareholders will be held at Idaho Power's Corporate Headquarters, 1221 W. Idaho St., Boise, Idaho at 10 a.m. local time on Thursday, May 16, 2013. Formal notice of the meeting will be mailed to shareholders on or about Wednesday, April 3, 2013.

Forward-Looking Statements

Please refer to IDACORP's and Idaho Power's Form 10-K for a description of the substantial risks and uncertainties related to the forward-looking statements included in this Annual Report.

IDACORP, Inc. — Boise, Idaho-based and formed in 1998 — is a holding company comprised of Idaho Power Company, a regulated electric utility; IDACORP Financial, a holder of affordable housing projects and other real estate investments; and Ida-West Energy, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. IDACORP's origins lie with Idaho Power and operations beginning in 1916. Today, Idaho Power employs approximately 2,000 people to serve a 24,000-square-mile service area in southern Idaho and eastern Oregon. With 17 low-cost hydroelectric projects as the core of its generation portfolio, Idaho Power's more than 500,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about Idaho Power or IDACORP, Inc., visit www.idahopower.com or www.idacorpinc.com.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2012

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

State of incorporation: Idaho

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:	Name of exchange on which registered
IDACORP, Inc.: Common Stock, without par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes (X) No ( )

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes (X) No ( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.

IDACORP, Inc.:

Large accelerated filer	(X)	Accelerated filer	( )	Non-accelerated filer	( )	Smaller reporting company	( )

Idaho Power Company:

Large accelerated filer	( )	Accelerated filer	( )	Non-accelerated filer	(X)	Smaller reporting company	( )

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Aggregate market value of voting and non-voting common stock held by non-affiliates (June 30, 2012):

IDACORP, Inc.: $ 2,087,821,219 Idaho Power Company: None

Number of shares of common stock outstanding as of February 15, 2013:

IDACORP, Inc.: 50,143,416

Idaho Power Company: 39,150,812, all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14	Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders.

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2013 annual meeting of shareholders.

COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are found in multiple locations within this report:

ADITC	- Accumulated Deferred Investment Tax Credits
AFUDC	- Allowance for Funds Used During Construction
AMI	- Advanced Metering Infrastructure
aMW	- Average Megawatts
APCU	- Annual Power Cost Update
BACT	- Best Available Control Technology
BCC	- Bridger Coal Company, a joint venture of IERCo
BLM	- U.S. Bureau of Land Management
BPA	- Bonneville Power Administration
CAA	- Clean Air Act
CAMP	- Comprehensive Aquifer Management Plan
CO_2	- Carbon Dioxide
CWA	- Clean Water Act
DOE	- U.S. Department of Energy
DSM	- Demand-Side Management
EGUs	- Electric Utility Generating Units
EIS	- Environmental Impact Statement
EPA	- U.S. Environmental Protection Agency
EPS	- Earnings Per Share
ESA	- Endangered Species Act
FASB	- Financial Accounting Standards Board
FCA	- Fixed Cost Adjustment Mechanism
FERC	- Federal Energy Regulatory Commission
FPA	- Federal Power Act
GAAP	- Generally Accepted Accounting Principles
GHG	- Greenhouse Gas
HAPS	- Hazardous Air Pollutants
HCC	- Hells Canyon Complex
Ida-West	- Ida-West Energy, a subsidiary of IDACORP, Inc.
Idaho ROE	- Idaho-jurisdiction return on year-end equity
IERCo	- Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IESCo	- IDACORP Energy Services Co., a subsidiary of IDACORP, Inc.
IFS	- IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPUC	- Idaho Public Utilities Commission
IRP	- Integrated Resource Plan
IRS	- U.S. Internal Revenue Service
kW	- Kilowatt
LCAR	- Load Change Adjustment Rate
MACT	- Utility Maximum Available Control Technology
MD&A	- Management's Discussion and Analysis of Financial Condition and Results of Operations
MW	- Megawatt
MWh	- Megawatt-hour
NAAQS	- National Ambient Air Quality Standards
NOAA	- National Oceanic and Atmospheric Administration
NOx	- Nitrous Oxide
NSPS	- New Source Performance Standards
NSR/PSD	- New Source Review / Prevention of Significant Deterioration
O&M	- Operations and Maintenance
OATT	- Open Access Transmission Tariff
OPUC	- Oregon Public Utility Commission
PCA	- Power Cost Adjustment
PCAM	- Power Cost Adjustment Mechanism
PURPA	- Public Utility Regulatory Policies Act of 1978
REC	- Renewable Energy Certificate
RES	- Renewable Energy Standard
RPS	- Renewable Portfolio Standard
SEC	- U.S. Securities and Exchange Commission
SMSP	- Senior Management Security Plan
SO_2	- Sulfur Dioxide
USBR	- U.S. Bureau of Reclamation
USFWS	- U.S. Fish and Wildlife Service
VIEs	- Variable Interest Entities

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations and, as such, constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, or future events or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "targets" "may result," "may continue," or similar expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Part 1 - Item 1A - "Risk Factors" of this report and the following important factors:

- Idaho Power's rate design and the effect of regulatory decisions by the Idaho and Oregon public utilities commissions, the Federal Energy Regulatory Commission, and other regulators affecting Idaho Power's ability to recover costs and earn a return;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, and the availability and use of energy efficiency and conservation programs, and the associated impact on loads and load growth;
- the impacts of changes in economic conditions, including the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and collections;
- unseasonable or severe weather conditions, wildfires, and other natural phenomena, which affect customer demand, hydroelectric generation levels, infrastructure repair costs, and the ability and cost to procure fuel for generation plants or purchased power to serve customers;
- advancement of new technologies that reduce loads or render Idaho Power's generation facilities obsolete;
- adoption of or changes in, and costs of compliance with, laws, regulations, and policies relating to the environment, natural resources, and endangered species, and the ability to recover those costs through rates;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River basin, which can impact the amount of generation from Idaho Power's hydroelectric facilities;
- the ability to purchase fuel and power from suppliers on favorable payment terms and prices, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires, explosions, and mechanical breakdowns that may occur while operating and maintaining an electric system, which can cause unplanned outages, reduce generating output, damage the companies' assets or operations, subject the companies to third-party claims for property damage, personal injury, or loss of life, or result in the imposition of civil, criminal, or regulatory fines or penalties;
- the ability to obtain debt and equity financing or refinance existing debt when necessary and on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets (including as a result of European sovereign debt issues) and interest rate fluctuations, decisions by the Idaho or Oregon public utility commissions, and the companies' past or projected financial performance;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to existing power purchase and credit arrangements;
- the ability to buy and sell power, transmission capacity, and fuel in the markets and the availability to enter into financial and physical commodity hedges with creditworthy counterparties, including the impact of federal legislation on counterparties' willingness to transact, market liquidity, and hedging costs, which may affect fuel and power availability and pricing, and the failure of any such risk management and hedging strategies to work as intended;
- changes in or implementation of Federal Energy Regulatory Commission and other mandatory reliability, security, and other requirements for system infrastructure, which could result in penalties and increase costs;
- disruptions or outages of Idaho Power's generation or transmission systems or the western interconnected transmission system;
- the costs and operational challenges of integrating an increasing volume of mandated purchased intermittent wind power or other renewable energy sources into Idaho Power's resource portfolio;

- further increases in the unfunded liability or changes in actuarial assumptions, the interest rate environment, and the actual return on plan assets for pension and other post-retirement plans, which can affect future funding obligations, costs, and pension and other post-retirement plan liabilities;
- the ability to continue to pay dividends under the terms of the companies' credit arrangements and regulatory limitations, and whether the companies' boards of directors will continue to declare dividends based on the boards of directors' periodic consideration of factors affecting IDACORP's and Idaho Power's dividend policies;
- changes in tax laws or related regulations or new interpretations of applicable laws by federal, state, or local taxing jurisdictions, the availability of tax credits, and the tax rates payable by IDACORP shareholders on common stock dividends;
- employee workforce factors, including the operational and financial costs of unionization or the attempt to unionize all or part of the companies' workforce, the impact of an aging workforce, the cost and ability to retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, which may result in penalties and increase the cost of compliance, the nature and extent of investigations and audits, and costs of remediation;
- the inability to obtain, and cost of obtaining and complying with, required governmental permits and approvals, licenses, rights-of-way, and siting for transmission and generation projects and hydroelectric facilities;
- the cost and outcome of litigation, dispute resolution, regulatory proceedings, and penalties, and the ability to recover those costs or the costs of operational changes through insurance, rates, or from third parties;
- the failure of information systems or the failure to secure information system data, security breaches, or the direct or indirect effect on the companies' business resulting from the occurrence of cyber attacks, terrorist incidents, or the threat of terrorist incidents, and acts of war;
- adoption of or changes in accounting policies, principles, or estimates, including the potential adoption of all or a portion of International Financial Reporting Standards, and new Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations of existing requirements; and
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement technology solutions.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

PART I
ITEM 1. BUSINESS

OVERVIEW

IDACORP, Inc. (IDACORP) is a holding company incorporated in 1998 under the laws of the state of Idaho, and its principal operating subsidiary is Idaho Power Company (Idaho Power). IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes record retention and reporting requirements on IDACORP.

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as the successor to a Maine corporation organized in 1915. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and is regulated by the 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.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), which held a 99-percent limited partnership interest in IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003. IE merged with and into IESCo effective December 31, 2012.

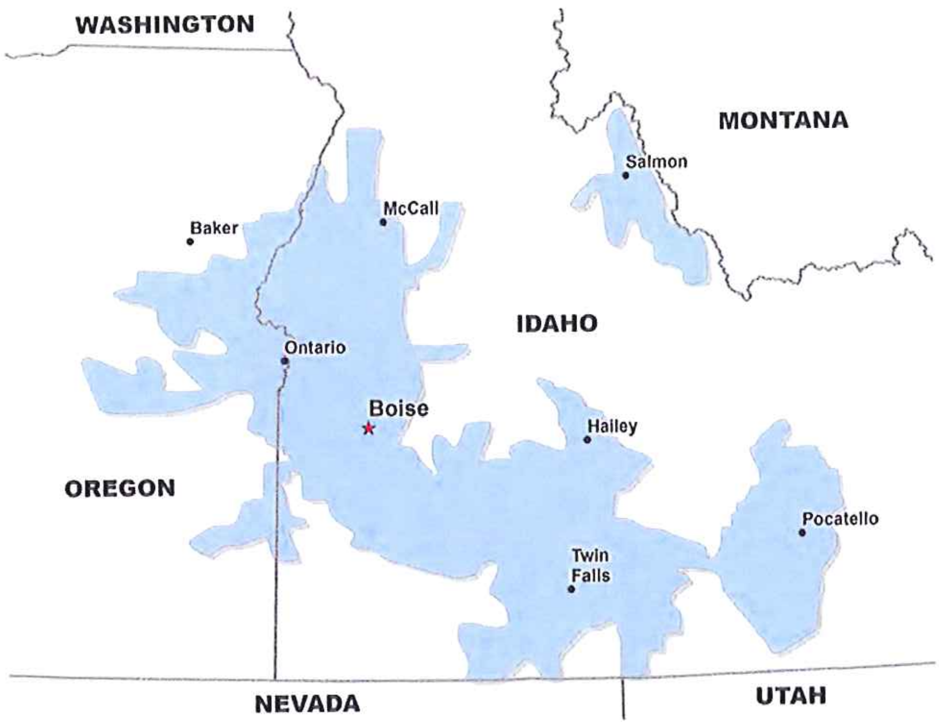
Idaho Power is IDACORP's only reportable business segment, contributing substantially all of IDACORP's net income in 2012. Segment data is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2012, IDACORP had 2,079 full-time employees, 2,067 of whom were employed by Idaho Power, and 21 part-time employees, 20 of whom were employed by Idaho Power.

IDACORP and Idaho Power make available free of charge on their websites their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is *www.idacorpinc.com* and can also be accessed through a link on the Idaho Power website at *www.idahopower.com*. The contents of the above-referenced website addresses are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC's website, *www.sec.gov*, or from the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

IDACORP's and Idaho Power's principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

UTILITY OPERATIONS

Idaho Power's service territory covers approximately 24,000 square miles in southern Idaho and eastern Oregon, with an estimated population of one million. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 71 cities in Idaho and nine cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 25 counties in Idaho and three counties in Oregon. As of December 31, 2012, Idaho Power supplied electric energy to approximately 501,000 general business customers. Idaho Power's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, forest products, beet sugar refining, and winter recreation. Idaho Power's service territory is illustrated on the following page.



Weather, customer demand, and economic conditions impact electricity sales and costs and, therefore, Idaho Power's utility revenues are not earned and associated expenses are not incurred evenly during the year. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps. Idaho Power's retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter.

Electric utilities have historically been recognized as natural monopolies and have operated in a highly regulated environment in which they have an obligation to provide electric service to their customers in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), and as a regulated electric utility Idaho Power is generally not subject to retail competition. Idaho Power is also under the jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. Further, the FERC has jurisdiction over, among other items, Idaho Power's transmission and wholesale sales of electricity, hydroelectric relicensing, and system reliability.

General Business Strategy

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. Idaho Power continuously evaluates and refines its business strategy to ensure coordination among and integration of all functional areas of the company. Idaho Power's business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company's financial stability and flexibility. The strategy includes:

- ***Responsible Planning***: Idaho Power's planning process is intended to ensure adequate generation and transmission resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power's regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.
- ***Responsible Development and Protection of Resources***: Idaho Power's business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural

resources Idaho Power and the communities it serves depend upon. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.

- ***Responsible Energy Use***: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards (RPS) legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions.

Rates and Revenues

The prices that the IPUC and OPUC authorize Idaho Power to charge for its electric service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. In addition to the discussion below, see the "Regulatory Matters" section of Part II, Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) and Note 3 – "Regulatory Matters" to the consolidated financial statements included in this report.

Retail Rates: Idaho Power periodically evaluates the need to seek changes to its retail electricity price structure to cover its operating costs and provide an opportunity for a reasonable rate of return. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA), balancing accounts and riders, and subject-specific filings to recover its costs of providing service and to earn a return on investment. Retail prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, public hearings, and the issuance of a final order. Participants in these proceedings, which are conducted under established procedures and schedules, include Idaho Power, the staffs of the IPUC or OPUC, and other interested parties. The IPUC and OPUC are required to ensure that the prices and terms of service are fair, non-discriminatory, and provide Idaho Power an opportunity to recover its costs and earn a fair return on investment. This requirement does not, however, ensure that Idaho Power will earn a specified rate of return. In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific authorization from the IPUC or OPUC. Deferred amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Wholesale Markets: As a public utility under Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its Open Access Transmission Tariff (OATT). Idaho Power's OATT is revised each year based on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power participates in the wholesale energy markets by purchasing power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans, which are influenced by customer load, market prices, generating costs, transmission constraints, and availability of generating resources. Some of Idaho Power's 17 hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric generation units and when to store water in reservoirs. These decisions affect the timing and volumes of market purchases and market sales. Even in below-normal water years, there are opportunities to vary water usage to maximize generation unit efficiency, capture marketplace economic benefits, and meet load demand. Wholesale energy market prices and compliance factors, such as allowable river stage elevation changes and flood control requirements, influence these dispatch decisions.

Energy Sales: The following table presents Idaho Power's revenues and energy use by customer type for the last three years. Approximately 95 percent of Idaho Power's general business revenue comes from customers located in Idaho, with the remainder coming from customers located in Oregon. Idaho Power's operations, including information on energy sales, are discussed further in Part II, Item 7 - "MD&A - Results of Operations - Utility Operations."

	Year Ended December 31,		
	2012	2011	2010
Revenues (thousands of dollars)			
Residential	$ 431,555	$ 405,982	$ 400,607
Commercial	241,519	220,962	231,440
Industrial	145,054	140,701	138,394
Irrigation	137,424	104,635	110,555
Provision for rate refund for sharing mechanism	(7,151)	(27,099)	—
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,636)	(10,636)	(10,625)
Total general business revenues	937,765	834,545	870,371
Off-system sales	61,534	101,602	78,133
Other	77,426	86,581	84,548
Total revenues	$ 1,076,725	$ 1,022,728	$ 1,033,052
Energy use (thousands of MWh)			
Residential	5,039	5,146	4,967
Commercial	3,865	3,815	3,763
Industrial	3,133	3,100	3,076
Irrigation	2,048	1,673	1,707
Total general business	14,085	13,734	13,513
Off-system sales	2,183	3,635	1,982
Total	16,268	17,369	15,495

Power Supply

Idaho Power primarily relies on company-owned hydroelectric, coal, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River basin. Market purchases and sales are used to supplement Idaho Power's generation and balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, and economic conditions impact power supply costs. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and wholesale market purchased power. Economic conditions and governmental regulations can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power. Idaho Power has PCA mechanisms in Idaho and Oregon that mitigate in large part the potential adverse financial statement impacts of volatile fuel and power costs.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand was 3,245 MW, set on July 12, 2012, and the all-time winter peak demand was 2,527 MW, set on December 10, 2009. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. The following table presents Idaho Power's total power supply for the last three years.

	MWh			Percent of Total Generation		
	2012	2011	2010	2012	2011	2010
	(thousands of MWh)					
Hydroelectric plants	7,956	10,937	7,344	57%	69%	51%
Coal-fired plants	5,227	4,820	6,864	38%	30%	48%
Natural gas fired plants	676	138	160	5%	1%	1%
Total system generation	13,859	15,895	14,368	100%	100%	100%
Purchased power - cogeneration and small power production	1,961	1,495	910			
Purchased power - other	1,709	1,256	1,491			
Total purchased power	3,670	2,751	2,401			
Total power supply	17,529	18,646	16,769			

Hydroelectric Generation: Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 8.6 million MWh under median water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall, amount and timing of water leases, and other weather and stream flow considerations. Power generation at the Idaho Power hydroelectric power plants on the Snake River also depends on the state water rights held by Idaho Power and the long-term sustainability of the Snake River, tributary spring flows, and the Eastern Snake Plain Aquifer that is connected to the Snake River. Idaho Power continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River. For more information on water management issues see Note 10 - "Contingencies" to the consolidated financial statements included in this report. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced, resulting in a reliance on other generation resources and power purchases.

Below average snow accumulation in the Snake River basin resulted in below average stream flow in 2012. As a consequence, annual generation from Idaho Power's hydroelectric facilities was 3.0 million MWh lower in 2012 than in 2011. The Northwest River Forecast Center of the National Oceanic and Atmospheric Administration reported that Brownlee Reservoir (part of the Hells Canyon Complex) inflow for April through July 2012 was 5.5 million acre-feet (maf). By comparison, April through July Brownlee Reservoir inflow was 10.5 maf in 2011 and 4.6 maf in 2010.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental issues. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex project, its largest hydroelectric generation source. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power's Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee" by virtue of its hydroelectric operations. As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described in the FPA and related FERC regulations. These conditions and regulations include provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment, severance damages, and other matters.

Coal-Fired Generation: Idaho Power co-owns the following coal-fired power plants:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- Valmy located in Nevada, in which Idaho Power has a 50 percent interest; and
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest.

Idaho Power, through its subsidiary IERCo, owns a one-third interest in BCC, which owns the Jim Bridger mine that supplies coal to the Jim Bridger power plant. PacifiCorp operates both the Jim Bridger mine and the Jim Bridger power plant. The mine, located near the Jim Bridger plant, operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface, high-wall, and underground sources. Idaho Power believes that the Jim Bridger mine has sufficient reserves to provide coal deliveries for at least the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2014 from the Black Butte Coal Company's Black Butte mine located near the Jim Bridger plant. This contract supplements the Jim Bridger mine deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant's rail load-in facility and unit coal train provide the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

NV Energy, Inc., as the operator of the Valmy generating plant, has agreements with coal suppliers through 2015. Idaho Power's share of these agreements along with existing coal inventory at the plant are expected to meet Idaho Power's projected coal supply needs for 2013 and 2014, and approximately 60 percent of its supply needs for 2015. As a 50-percent owner of the plant, Idaho Power is obligated to purchase one-half of the coal obtained under these contracts.

The Boardman generating plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Portland General Electric Company is the operator of the Boardman plant. All of the Boardman plant's projected coal requirements in 2013 and approximately 33 percent of projected coal requirements in 2014 are under contract. A portion of the 2013 and 2014 coal purchased will be low sulfur content as Boardman prepares for the 2015 transition to a lower sulfur fuel content. As a ten percent owner of the plant, Idaho Power is obligated to purchase ten percent of the coal obtained under these agreements. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020.

Natural Gas-fired Generation: Idaho Power owns and operates the Langley Gulch natural gas-fired combined cycle power plant and the Danskin and Bennett Mountain natural gas-fired simple cycle combustion turbine power plants. All three plants are located in Idaho. The Langley Gulch power plant was placed into service in June 2012, contributing to the notable increase in gas-fired generation during 2012 relative to prior years.

Idaho Power operates the Langley Gulch plant as a base load unit and the Danskin and Bennett Mountain plants to meet peak supply needs. The plants are also used to take advantage of wholesale market opportunities. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is transported through the Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. These transportation agreements vary in contract length, with the latest termination date of May 2042, but with extensions at Idaho Power's discretion. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. This firm storage contract expires in 2043. Idaho Power purchases and stores natural gas with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

As of December 31, 2012, approximately 3.2 million MMBtu's of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through December 2013. Idaho Power plans to manage the procurement of additional natural gas for the peaking units on the daily spot market or from storage inventory as necessary to meet system requirements and fueling strategies.

***Purchased Power Agreements*:** Idaho Power purchases power in the wholesale market and pursuant to long-term power purchase contracts, as described below.

Wholesale Market Purchases: Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk management policy limitations, and unit availability. Idaho Power seeks to manage its loads efficiently by utilizing its generation resources and long-term power purchase contracts in conjunction with buying and selling opportunities in the wholesale market. In addition to its market purchases, Idaho Power has the following notable firm wholesale power purchase contracts and energy exchange agreements:

- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033.
- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.

- USG Oregon LLC - for 22 MW (estimated average annual output) from the Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is 25 years with an option to extend. This project achieved commercial operation in November 2012.
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock hydroelectric project in southern Idaho in exchange for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

During 2012, Idaho Power purchased 1.7 million MWh of power through wholesale market purchases at an average price of $46.41 per MWh. During 2011, Idaho Power purchased 1.3 million MWh of power through wholesale market purchases at an average cost of $58.19 per MWh.

PURPA Power Purchase Contracts: Idaho Power purchases power from PURPA projects as mandated by federal law. As of December 31, 2012, Idaho Power had 779 MW nameplate capacity of PURPA-related projects on-line, with an additional 52 MW nameplate capacity of projects projected to be on-line by the end of 2014. The power purchase contracts for these projects have terms ranging from one to 35 years. The expense and volume of PURPA project power purchases during the last three years is included in the table below.

	Year Ended December 31,		
	2012	2011	2010
PURPA contract expense (in thousands)	$ 117,618	$ 90,251	$ 56,022
MWh purchased under PURPA contracts (in thousands)	1,961	1,495	910
Average cost per MWh from PURPA contracts	$ 59.98	$ 60.36	$ 61.56

The bulk of the increase in volume of PURPA power purchases resulted from additional wind projects. Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions having jurisdiction over Idaho Power have each issued orders and rules regulating Idaho Power's purchase of power from "qualifying facilities" that meet the requirements of PURPA. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility's avoided costs. The IPUC and OPUC have established specific rules and regulations to calculate the avoided cost that Idaho Power is required to include in PURPA contracts. For PURPA power purchase agreements:

- Idaho Power is required to purchase all of the output from the facilities located inside its service territory, subject to some exceptions such as adverse impacts on system reliability.
- Idaho Power is required to purchase the output of projects located outside its service territory if it has the ability to receive power at the facility's requested point of delivery on Idaho Power's system.
- The IPUC jurisdictional portion of the costs associated with PURPA contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and an Oregon PCA mechanism.
- IPUC and OPUC jurisdictional regulations allow PURPA standard contract terms to be up to 20 years.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 kW and all other types of projects that are smaller than 10 average MWs. For PURPA qualifying facilities that exceed these size limitations, Idaho Power is required to negotiate an applicable price (premised on avoided costs) based upon IPUC regulations.
- The OPUC requires that Idaho Power pay the published avoided costs for all PURPA qualifying facilities with a nameplate rating of 10 MW or less and that Idaho Power negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations.

Idaho Power, as well as other power utilities with an Idaho service territory, has been engaged in proceedings at the IPUC and OPUC relating to PURPA contract terms, including the prices paid for energy purchased from PURPA projects. Refer to "MD&A - Regulatory Matters - Renewable Energy Contracts, Renewable Energy Certificates, and Emission Allowances" for a summary of those proceedings.

Transmission Services

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located anywhere from a few miles to hundreds of miles from customers. Idaho Power's generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum capability and reliability. Idaho Power's transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy, Inc. These interconnections, coupled with transmission line capacity made available under agreements with some of those entities, permit the interchange, purchase, and sale of power among entities in the Western Interconnection. Idaho Power provides wholesale transmission service and provides firm and non-firm wheeling services for eligible transmission customers. Idaho Power is a member of the Western Electricity Coordinating Council, the Northwest Power Pool, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the Western Interconnection.

Resource Planning

Integrated Resource Plan: The IPUC and OPUC require that Idaho Power biennially prepare an Integrated Resource Plan (IRP). Idaho Power filed its 2011 IRP with the IPUC and OPUC in June 2011. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The 2011 IRP was accepted by the IPUC in December 2011 and acknowledged by the OPUC in February 2012. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

Idaho Power updates the IRP every two years and preparation of the 2013 IRP is in process. Idaho Power expects that the 2013 IRP will be completed and filed in June 2013. During the time between resource plan filings, the public and regulatory oversight of the activities identified in the 2011 IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect changes in technology, economic conditions, anticipated resource development, and regulatory requirements.

The 2011 IRP included as new generation resources the 318-MW Langley Gulch natural-gas fired power plant, which came on-line in June 2012, and a 49-MW expansion of the Shoshone Falls hydroelectric facility, which is under evaluation and unlikely to be constructed prior to 2019. The 2011 IRP also identified the Boardman-to-Hemingway transmission line in the preferred resource portfolio. Idaho Power believes the Boardman-to-Hemingway transmission line and the existing Hemingway substation, together with the Gateway West transmission line, will improve reliability, relieve transmission congestion, and provide system flexibility. Additional information about Idaho Power's significant infrastructure development projects is included in Item 7 - "MD&A - Liquidity and Capital Resources - Capital Requirements - Major Infrastructure Projects."

Preliminary work performed in connection with Idaho Power's 2013 IRP indicates more moderate load growth rates in Idaho Power's service area than what was forecast in the 2011 IRP. The moderation in load growth is in large part the result of changes in expectations surrounding economic conditions, anticipated electricity price increases incorporating impacts of carbon legislation, loss of anticipated load from the Hoku Materials, Inc. special customer contract, and the elimination of an anticipated but unidentified special contract customer that had been included in the 2011 IRP. The 2013 IRP median annual average load forecast projects growth of 1.1 percent annually over the next 20 years, whereas the 2011 IRP included a forecast growth rate of 1.4 percent. For median peak-hour load, the 2013 IRP is expected to project an annual average growth rate of 1.4 percent whereas the 2011 IRP included a forecast growth rate of 1.8 percent. Accounting for the reduced load growth and excluding approximately 400 MW of demand response programs, the preliminary 2013 IRP load and resource balance forecasts the first resource capacity deficit will not occur until the summer of 2016 under one scenario. Although the 2013 IRP is projected to forecast lower load growth rates, there is still much uncertainty regarding the rate of recovery from the recession and the subsequent impact on Idaho Power's future load growth. Idaho Power expects to be able to manage any near-term summer peak capacity deficits until completion of the Boardman-to-Hemingway transmission line, which is expected in 2018 at the earliest. If the Boardman-to-Hemingway line is not constructed by the time necessary to meet load demands, Idaho Power will need to identify alternatives to meet load requirements.

In response to the operational challenges associated with integrating intermittent wind power that Idaho Power must purchase pursuant to PURPA, and the recognition that the costs and challenges associated with integrating intermittent resources will become even more pronounced as the volume of intermittent resources in Idaho Power's portfolio increases, Idaho Power continues efforts to better understand the effects of wind generation on power system operation. As part of these efforts, Idaho Power issued its first wind integration study in 2007, and in late 2012 completed a second, more comprehensive wind integration study. The goal of the most recent study was to assess the additional costs incurred in modifying operations of Idaho Power's dispatchable generating resources to compensate for the variable and intermittent energy supplied by wind generators while maintaining reliable energy delivery to customers. Additionally, the study aimed to provide insight on the maximum amount of wind generation Idaho Power's system can accommodate without impacting reliability. Idaho Power has committed considerable resources to the study, including working with an independent consultant, utility industry peers, and interested parties, and has held public workshops. Idaho Power released the report publicly in February 2013 as part of its 2011 IRP update. In further response to the integration challenges, Idaho Power has implemented an internally developed wind forecasting system, in recognition that cost-intensive modifications to operations intended to integrate wind are reduced, though not eliminated, with improved wind production forecasting.

On or before January 1, 2020, Idaho Power is required to own or contract to purchase the capacity and output from a qualifying solar photovoltaic (PV) system with a minimum capacity of 500 kW pursuant to the state of Oregon's solar PV capacity standard. The timing of development of this required project in Oregon and the solar demonstration project referenced in Idaho Power's 2011 IRP will depend in large part on Idaho Power's ability to resolve integration, reliability, and cost issues associated with the recent influx of PURPA resources from which Idaho Power is currently mandated to purchase power. However, with the cost of solar PV technology continuing to decrease, Idaho Power believes this technology will become more prevalent in its service area over the long term. Idaho Power continues to evaluate the timing for proceeding with solar PV technology.

Energy Efficiency and Demand Response Programs: Idaho Power has 18 energy efficiency and demand response programs targeting energy savings across the entire year and summer system demand reduction. These programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new infrastructure. Idaho Power's programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes, including efficient appliances and HVAC equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes; and
- demand response programs to reduce peak summer demand through the voluntary interruption of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through a third-party demand response aggregator.

In 2012, Idaho Power's energy efficiency programs reduced energy usage by approximately 157,000 MWh. Idaho Power's demand response programs had available capacity of approximately 411 MW; however, because of a relatively high cost to dispatch Idaho Power's Irrigation Peak Rewards program it was not used in 2012. Idaho Power realized approximately 91 MW in summer peak demand reduction through the A/C Cool Credit and the FlexPeak Management programs as these programs have no marginal dispatch costs. In December 2012, Idaho Power filed with the IPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs for the summer of 2013 in order to work with stakeholders and IPUC Staff to explore the near-term need for and design of the demand response programs. A settlement stipulation relating to temporary suspension of the programs is pending before the IPUC.

In 2012, Idaho Power spent approximately $49.3 million on energy efficiency and targeted demand reduction response programs. Approximately $27.1 million annually of funding for these programs is provided by Idaho and Oregon energy efficiency tariff riders, while the balance of the funding comes from Idaho Power base rates and the PCA mechanism. In 2012, as approved by the IPUC, Idaho Power capitalized approximately $6 million of custom efficiency program incentives as a regulatory asset. For expenditures in 2012, Idaho Power will also recover approximately $14.5 million in demand response incentives through its annual PCA as approved by the IPUC.

Approximately $4.7 million of Idaho Power's 2012 energy efficiency spending was related to research and analysis, education, technology evaluation, and market transformation. Most of this activity was done in conjunction with the Northwest Energy Efficiency Alliance.

Environmental Regulation and Costs

Idaho Power's activities are subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment. Environmental regulation continues to impact Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, and the modification of system operations to accommodate environmental regulations. In addition to generally applicable regulations, the FERC licenses issued for Idaho Power's hydroelectric generating plants have environmental requirements such as aeration of turbine water to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power's three coal-fired power plants and three natural gas combustion turbine power plants are also subject to a broad range of environmental requirements, including air quality regulation. For a more detailed discussion of these and other environmental issues, refer to Item 7 – "MD&A – Environmental Matters" in this report.

Cost Estimates: Idaho Power's environmental compliance expenditures will continue to be significant for the foreseeable future, especially with potential additional regulation under discussion at the federal level. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

Environmental Expenditures	2013	2014 - 2015
Capital expenditures:		
Studies and measures at hydroelectric facilities	$ 12	$ 41
Investments in equipment and facilities at thermal plants	50	94
Total capital expenditures	$ 62	$ 135
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$ 21	$ 49
Operating costs for environmental facilities - thermal	8	22
Total operations and maintenance	$ 29	$ 71

Idaho Power anticipates that a number of new and impending EPA rulemakings and proceedings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs in addition to the amounts set forth above, but Idaho Power is unable to estimate those costs given the uncertainty associated with pending regulations.

Environmental Controls Cost Study: In connection with its IRP process, Idaho Power has been conducting cost studies and scenario analyses to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal-fired generation facilities. The Boardman plant was not included in the study because of the existing schedule to cease coal-fired operations at that plant by the end of 2020. Some of the future environmental control requirements for the Jim Bridger and Valmy plants are known; however, additional requirements could arise from future regulations. In the analysis, the cost of future compliance was compared to the cost of replacement generation capacity provided by combined-cycle combustion turbine technology and conversion of the units to natural gas. Because of the speculative nature of many of the future requirements, the analysis was performed under a range of fuel pricing assumptions, carbon cost assumptions, plant upgrade and retirement costs, environmental regulation assumptions, and replacement costs. Idaho Power published the results of the study with its 2011 IRP update filed with the IPUC and OPUC in February 2013. Idaho Power concluded in its study that the Jim Bridger and Valmy plants should be retained in its resource portfolio and supports planned investments in environmental controls at those plants. This is particularly true in light of the desire to maintain a diversified portfolio of generation assets and fuel diversity that can mitigate risk associated with increases in natural gas prices. However, the study also concluded that in the event significant additional operating and maintenance or capital expenditures are necessary at the Valmy plant as a result of new environmental requirements, Idaho Power will conduct a further review to determine whether such investments are economically appropriate, and whether conversion of the facility to a natural-gas fired plant would be appropriate.

Inaugural Sustainability Report: In May 2012, IDACORP publicly issued its inaugural sustainability report. The sustainability report highlights Idaho Power's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship. IDACORP plans to issue its second sustainability report in May 2013 and make it available on its or Idaho Power's website.

Extension of Idaho Power's Voluntary CO_2 Intensity Reduction Goal: While there is currently no national mandatory greenhouse gas reduction requirement, Idaho Power continues to prepare for potential legislative and/or regulatory restrictions on emissions in order to help reduce the costs of complying with such restrictions on its customers. To that end, Idaho Power is engaged in voluntary greenhouse gas emission intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce Idaho Power's resource portfolio's average carbon dioxide (CO_2) emission intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh. Idaho Power's estimated CO_2 emission intensity from its generation facilities, as submitted to the Carbon Disclosure Project, was 672, 1,051, and 1,004 lbs/MWh for 2011, 2010, and 2009 respectively. As of the date of this report, Idaho Power is on track to exceed the CO_2 emission intensity reduction goal it established in 2009. The combination of effective utilization of hydroelectric projects, above average stream flows, reduced usage of coal-fired facilities, and addition of the Langley Gulch natural gas-fired power plant have positioned Idaho Power to extend its CO_2 intensity reduction goal period for an additional two years, targeting an average reduction of 10 to 15 percent below its 2005 levels for the entire 2010 through 2015 time period.

IFS

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS generated tax credits of $5.5 million, $6.4 million, and $7.3 million in 2012, 2011, and 2010, respectively. IFS's portfolio also includes historic rehabilitation projects such as the Empire Building in Boise, Idaho. IFS made no new investments in 2012 or 2011, but did have $7 million of new investments during 2010.

IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk. Over 90 percent of IFS's investments have been made through syndicated funds. At December 31, 2012, the gross amount of IFS's portfolio equaled $195 million in tax credit investments. These investments cover 49 states, Puerto Rico, and the U.S. Virgin Islands. The underlying investments include approximately 570 individual properties, of which all but four are administered through syndicated funds.

IDA-WEST

Ida-West operates and has a 50 percent interest in nine hydroelectric plants with a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $9 million, $9 million, and $8 million in 2012, 2011, and 2010, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below, along with their business experience during at least the past five years. Mr. J. LaMont Keen and Mr. Steven R. Keen are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was appointed.

Senior Executive Officers (in alphabetical order)

DARREL T. ANDERSON, 54

- President and Chief Financial Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 1, 2009 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - September 30, 2009.

REX BLACKBURN, 57

- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 1, 2009 - present.
- Senior Attorney, Idaho Power Company, January 1, 2008 - March 31, 2009.

LISA A. GROW, 47

- Senior Vice President, Power Supply of Idaho Power Company, October 1, 2009 - present.
- Vice President - Delivery Engineering and Operations of Idaho Power Company, July 20, 2005 - September 30, 2009.

J. LAMONT KEEN, 60

- President and Chief Executive Officer of IDACORP, Inc., July 1, 2006 - present.
- Chief Executive Officer of Idaho Power Company, November 17, 2005 - present.
- President of Idaho Power Company, March 1, 2002 - December 31, 2011.
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company.

STEVEN R. KEEN, 52

- Senior Vice President, Finance and Treasurer of Idaho Power Company, January 1, 2012 - present.
- Vice President, Finance and Treasurer of IDACORP, Inc., June 1, 2010 - present.
- Vice President, Finance and Treasurer of Idaho Power Company, June 1, 2010 - December 31, 2011.
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 1, 2006 - May 31, 2010.

DANIEL B. MINOR, 55

- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President of IDACORP, Inc., May 20, 2010 - present.
- Executive Vice President, Operations of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President - Delivery of Idaho Power Company, July 1, 2004 - September 30, 2009.

Other Executive Officers (in alphabetical order)

DENNIS C. GRIBBLE, 60

- Vice President and Chief Information Officer of Idaho Power Company, June 1, 2006 - present.
- Vice President and Chief Information Officer of IDACORP, Inc., June 1, 2006 - December 31, 2011.

PATRICK A. HARRINGTON, 52

- Corporate Secretary of IDACORP, Inc. and Idaho Power Company, March 15, 2007 - present.

WARREN KLINE, 57

- Vice President, Customer Operations of Idaho Power Company, May 20, 2010 - present.
- Vice President - Customer Service and Regional Operations of Idaho Power Company, July 20, 2005 - May 19, 2010.

JEFFREY MALMEN, 45

- Vice President, Public Affairs of IDACORP, Inc. and Idaho Power Company, October 1, 2008 - present.
- Senior Manager - Governmental Affairs of IDACORP, Inc. and Idaho Power Company, December 10, 2007 - September 30, 2008.

LUCI K. MCDONALD, 55

- Vice President, Human Resources and Corporate Services of Idaho Power Company, May 20, 2010 - present
- Vice President, Human Resources and Corporate Services of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President - Human Resources of IDACORP, Inc. and Idaho Power Company, December 6, 2004 - May 19, 2010.

KEN W. PETERSEN, 49

- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Corporate Controller of IDACORP and Idaho Power Company, December 29, 2007 - May 19, 2010.

N. VERN PORTER, 53

- Vice President, Delivery Engineering and Construction, Idaho Power Company, May 17, 2012 - present.
- Vice President, Delivery Engineering and Operations, Idaho Power Company, October 1, 2009 - May 16, 2012.
- General Manager of Power Production of Idaho Power Company, April 22, 2006 - September 30, 2009.

GREGORY W. SAID, 58

- Vice President, Regulatory Affairs, Idaho Power Company, January 20, 2011 - present.
- General Manager of Regulatory Affairs, Idaho Power Company, April 3, 2010 - January 19, 2011.

- Director, State Regulation, Idaho Power Company, August 23, 2008 - April 2, 2010.
- Manager, Revenue Requirement, Idaho Power Company, November 14, 1998 - August 22, 2008.

NAOMI SHANKEL, 41

- Vice President, Supply Chain of Idaho Power Company, May 20, 2010 - present.
- Vice President, Supply Chain of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, September 21, 2006 - May 19, 2010.

LORI D. SMITH, 52

- Vice President, Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Vice President - Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2008 - May 19, 2010.

ITEM 1A. RISK FACTORS

The circumstances and factors set forth below may have a material impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements.

If the Idaho Public Utilities Commission, the Oregon Public Utility Commission, or the Federal Energy Regulatory Commission grant less rate recovery in regulatory proceedings than Idaho Power needs to cover existing and future costs and earn an acceptable rate of return, IDACORP's and Idaho Power's financial condition and results of operations may be adversely affected. The prices that the Idaho Public Utilities Commission and Oregon Public Utility Commission authorize Idaho Power to charge for its retail services, and the tariff rate that the Federal Energy Regulatory Commission permits Idaho Power to charge for its transmission services, are generally the most significant factors influencing IDACORP's and Idaho Power's business, results of operations, and financial condition. The Idaho Public Utilities Commission and Oregon Public Utility Commission have the authority to disallow recovery of any costs that they consider unreasonable or imprudently incurred. Also, the rates allowed by the Federal Energy Regulatory Commission for transmission service may be insufficient for recovery of costs incurred. The regulatory process does not assure that Idaho Power will be able to achieve the rate of return allowed by the Idaho and Oregon public utility commissions. Further, while the Idaho Public Utilities Commission and Oregon Public Utility Commission are required to establish rates that are fair, just, and reasonable, they have considerable discretion in applying this standard. The ratemaking process typically involves multiple parties, including governmental bodies, consumer advocacy groups, and customers. While each party has differing concerns, they often have the common objective of limiting rate increases or even reducing rates.

Idaho Power cannot predict the outcome of ratemaking proceedings, including what rates of return will be authorized, the extent to which costs will be allowed for recovery, or the timing of recovery. The failure of Idaho Power to obtain approvals from regulatory authorities to recover costs, construct new generating or transmission facilities, install environmental emission control equipment, or otherwise operate Idaho Power's business may adversely impact Idaho Power's ability to achieve its strategic plan, cause IDACORP and Idaho Power to record an impairment of their assets, and have a material adverse impact on their results of operations and financial condition. In a number of proceedings in recent years, Idaho Power has been denied recovery, or deferred recovery pending the next general rate case, including denials or deferrals related to compensation expenses and construction expenditures. For additional information relating to Idaho Power's regulatory framework and recent matters, see Item 1 - "Business - Utility Operations," Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, and Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Matters" in this report.

Idaho Power's cost recovery deferral mechanisms may not function as intended, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power has power cost adjustment mechanisms in its Idaho and Oregon jurisdictions and a fixed cost adjustment mechanism in Idaho that provide for periodic adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms track Idaho Power's actual net power supply costs (primarily fuel and purchased power less off-system sales) and compares these amounts to net power supply costs being recovered in retail rates. A majority, but not all, of the variance between these two amounts is deferred for future recovery from, or refund to, customers through rates. Consequently, the power cost adjustment mechanisms only partially offset the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydroelectric generation, and volatile wholesale energy prices. Because of the power cost adjustment mechanisms, the primary financial impact of power supply cost variations is on the timing of cash flows. When costs rise above the level recovered in current retail rates it adversely affects Idaho Power's operating cash flow and liquidity until those costs are recovered from customers.

Unanticipated changes in loads in Idaho Power's service territory expose Idaho Power to market and operational risk and could increase costs and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. While Idaho Power's customer growth rate has slowed in recent years, Idaho Power believes its service territory is an attractive one for both businesses and individuals. Idaho Power has recently adjusted its load forecast as part of its integrated resource planning process, predicting a lower growth rate over its 20-year resource planning horizon compared to prior estimates. In its efforts to balance loads and resources, Idaho Power makes load estimates that are based on a number of factors that are uncertain and difficult to estimate, and any unanticipated increase in the demand for energy could result in increased reliance on purchased power to meet peak system demand, the need to reinstate or initiate new demand response and energy efficiency programs, or the need for investment in additional generation resources. If the incremental costs associated with the unanticipated changes in loads exceed the incremental revenue and Idaho Power is unable to secure timely rate relief to recover those costs, the resulting disconnect between the time costs are incurred or investments are made and the time costs are recovered could have an adverse effect on IDACORP's or Idaho Power's financial condition and results of operations.

National and regional economic conditions may reduce customer growth rates, reduce energy consumption, or cause increased late payments and uncollectible customer accounts, which would adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Beginning in 2008, economic conditions in Idaho Power's service area have been relatively weak. Weak economic conditions may reduce the amount of energy Idaho Power's customers consume, result in a loss of customers (including large-load industrial and commercial customers) or further decrease the customer growth rate, and increase the likelihood and prevalence of late payments and uncollectible accounts. A resulting decrease in overall customer usage or collections and load growth at a rate less than anticipated may alter capital spending plans and rate base growth and may reduce revenues, earnings, and cash flows. Also, Idaho Power's regulatory mechanisms, including its load change adjustment rate and fixed cost adjustment mechanism in Idaho, are unlikely to result in Idaho Power recovering all of its costs related to load decreases, which would have a negative impact on IDACORP's and Idaho Power's financial condition and results of operations.

Extreme weather events and their associated impacts, such as high winds and fires, whether as a result of climate change or otherwise, can adversely affect IDACORP's and Idaho Power's results of operations and financial condition. Extreme weather events can damage generation facilities and disrupt transmission and distribution systems, causing service interruptions and extended outages, increasing supply chain costs, and limiting Idaho Power's ability to meet customer energy demand. Disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses and could negatively affect IDACORP's and Idaho Power's results of operation and financial condition.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could cause an erosion in revenues. With the escalating costs of energy has come the incentive for the development of new technologies for power generation and energy efficiency, and an investment in research and development to make those technologies more efficient and cost-effective. For instance, while solar technology remains a relatively high-cost means of power generation, there have been numerous recent advancements in the design of solar generation facilities and the materials used in panels (for example, copper indium gallium diselenide and amorphous silicon). These advancements may further increase the efficiency and power output of solar generation sources. Considerable emphasis has also been placed on energy efficiency and products that reduce electricity usage, such as LED lighting. There is potential that power generation systems provided by third parties, whether solar generation or otherwise, and energy efficiency measures could become sufficiently cost-effective and efficient that customers choose to install such systems on their homes or businesses. This may render traditional generation sources owned by Idaho Power obsolete or decrease the need for energy supplied by Idaho Power, which would reduce Idaho Power's revenue and have a negative impact on IDACORP's and Idaho Power's results of operations and financial condition.

Capital expenditures for power generation and delivery infrastructure and replacement of that infrastructure, and the timing and availability of cost recovery for those expenditures, can significantly affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power's business is capital intensive and requires significant investments in energy generation, transmission, and distribution infrastructure. Long-term increases in both the number of customers and the demand for energy require expansion and reinforcement of that infrastructure. For instance, Idaho Power is in the permitting process for two 500-kV transmission line projects. Construction projects are subject to usual construction risks that can adversely affect project costs and completion time. These risks include the ability to obtain labor or materials; increases in cost of labor and materials; contractor defaults; equipment, engineering, and design failures; adverse weather conditions; lack of availability of financing; the ability to obtain and comply with permits and land use rights; environmental constraints;

disputes and litigation with third parties; and changes in applicable laws or regulations. If Idaho Power is unable to complete the construction of a project, or incurs costs that regulators do not deem prudent, it may not be able to recover its costs in full through rates. Even if Idaho Power completes a construction project, the total costs may be higher than estimated and/or higher than amounts approved for recovery by regulators. If Idaho Power does not receive timely regulatory recovery of costs associated with those expansion and reinforcement activities, Idaho Power will have to rely more heavily on external debt or equity financing for its future capital expenditures. These large capital expenditures may weaken the consolidated financial profile of IDACORP and Idaho Power. Additionally, a significant portion of Idaho Power's facilities were constructed many years ago, which could affect reliability, increase repair and maintenance expenses, and increase reliance on market purchases of power, which may negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

Further, if Idaho Power were unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, such as the Boardman-to-Hemingway transmission line, it may terminate those projects and, as an alternative, develop additional generation facilities within areas where Idaho Power has available transmission capacity or pursue other more costly options to serve loads. Termination of a project carries with it the potential for a write-off of all or a significant portion of the costs associated with the project if state public utility commissions deny recovery of costs they deem imprudently incurred, which could negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's business is subject to an extensive set of environmental laws, rules, and regulations, which could impact Idaho Power's operations and increase costs of operations, potentially rendering some generating units uneconomical to maintain or operate, and could increase the costs and alter the timing of major projects. A number of federal, state, and local environmental statutes, rules, and regulations relating to air quality, water quality, natural resources, and health and safety are applicable to Idaho Power's operations. These laws and regulations generally require Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, inspections, and other approvals, and may be enforced by both public officials and private individuals. Some of these regulations are changing or subject to interpretation, and failure to comply may result in penalties or other adverse consequences. Environmental regulations have created the need for Idaho Power to install new pollution control equipment at, and may cause Idaho Power to perform environmental remediation on, its owned or co-owned facilities, often at a substantial cost. For instance, Idaho Power plans to install environmental control apparatus at its co-owned Jim Bridger power plant in 2015 and 2016 at a cost of approximately $120 million, and a second set of control apparatus in 2021 and 2022. Idaho Power expects that there will be other costs relating to environmental regulations, and those costs are likely to be substantial. Idaho Power is not guaranteed recovery of those costs. For instance, in December 2012 the Oregon Public Utility Commission disallowed in part cost recovery for certain environmental upgrades made to a coal plant by one of Idaho Power's Northwest region peer utilities, citing an insufficient cost analysis. If Idaho Power is similarly unable to recover in full its costs through the ratemaking process, such non-recovery would negatively impact IDACORP's and Idaho Power's financial condition and results of operations.

Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of fossil fuel plant emissions. Idaho Power cannot predict the outcome of pending or future legislative and rulemaking proposals, or the compliance costs Idaho Power would incur in connection with that legislation. Future changes in environmental laws or regulations governing emissions reduction may make certain electric generating units (especially coal-fired units) uneconomical and subject to shut-down, may require the adoption of new methodologies or technologies that significantly increase costs or delay in-service dates, and may raise uncertainty about the future viability of fossil fuels as an energy source for new and existing electric generation facilities. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its facilities and execution of its long-term strategy, including construction of new transmission and distribution infrastructure. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's generation or transmission facilities could be delayed, halted, or subjected to additional costs. At the same time, consumer preference for renewable or low greenhouse gas-emitting sources of energy could impact the desirability of generation from existing sources and require significant investment in new generation and transmission resources.

Relicensing of the Hells Canyon hydroelectric project and construction of the proposed Gateway West and Boardman-to-Hemingway transmission lines requires consultation under the Endangered Species Act to determine the effects of these projects on any listed species within the project areas. The listing of species as threatened or endangered will result in a costly Endangered Species Act consultation for the two transmission projects and for any future transmission projects. Similarly, the presence of sage grouse in the vicinity of the Gateway West and Boardman-to-Hemingway transmission projects has required more extensive, costly, and time consuming evaluation and engineering. These and other requirements of the Endangered

Species Act, Clean Air Act, Clean Water Act, and similar environmental laws may increase costs, the timing or ability to complete major projects, and reduce earnings and cash flows.

Factors contributing to lower hydroelectric generation can increase costs and negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. Because of Idaho Power's heavy reliance on hydroelectric generation, snowpack, the timing of run-off, and the availability of water in the Snake River basin can significantly affect its operations. The combination of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights may further reduce Snake River flows available for hydroelectric generation. When hydroelectric generation is reduced, Idaho Power must increase its use of more expensive thermal generating resources and purchased power; therefore, costs increase and opportunities for off-system sales are reduced, reducing earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most of the increase in net power supply costs caused by lower hydroelectric generation. Recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, negatively affecting cash flows and liquidity.

Conditions imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and negatively affect IDACORP's or Idaho Power's results of operations and financial condition. For the last several years, Idaho Power has been engaged in an effort to renew its federal license for its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The listing of various species of marine life, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. In particular, fish and other marine life recovery plans may require major operational changes to the region's hydroelectric projects. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power's energy requirements.

In 2007, the Federal Energy Regulatory Commission Staff issued a final environmental impact statement for the Hells Canyon Complex, which the Federal Energy Regulatory Commission will use in part to determine whether, and under what conditions, to issue a new license for the Hells Canyon Complex. Certain portions of the final environmental impact statement involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act and formal consultations under the Endangered Species Act, which remain unresolved. One significant issue involves water temperature gradients, and certain parties in the relicensing proceedings have advocated for the installation of water temperature management apparatus which, if required to be installed, would require substantial capital expenditures to construct and maintain. Idaho Power may be unable to recover in full the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, or whether a new multi-year license will ultimately be issued. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs, and reduce hydroelectric generation, which could negatively affect results of operations and financial condition.

IDACORP's and Idaho Power's operating results are subject to seasonal fluctuations, and unusually mild temperatures can impact their results of operations and financial condition. Electric power sales are generally seasonal, with demand in Idaho Power's service territory peaking during the hot summer months, with a secondary peak during the cold winter months. The loads required by irrigation customers in Idaho Power's service territory can also create significant seasonal changes in usage. When temperatures are relatively mild, loads are often lower as customers are not using electricity for heating and air conditioning purposes. Thus, unusually mild weather or the timing and extent of precipitation in the future could adversely impact IDACORP's and Idaho Power's results of operations and financial condition.

Complying with state or federal renewable portfolio standards could increase capital expenditures and operating costs and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. A number of states have adopted renewable portfolio standards, which require that electricity providers obtain a minimum percentage of their power from renewable energy sources by a specified date. Idaho Power's operations in Oregon will be required to comply with a ten percent renewable portfolio standard beginning in 2025, and it is possible that other states, including Idaho, could adopt renewable portfolio standards. The cost of purchasing or generating power from renewable energy sources is often greater than fossil fuel and hydroelectric generation sources, and construction of renewable energy facilities involves significant capital expenditures. As a result, new state or federal renewable portfolio standards could increase capital expenditures and operating costs and negatively affect results of operations and financial condition.

Idaho Power's reliance on coal and natural gas to fuel its non-hydroelectric power generation facilities exposes it to the risk of increased costs and reduced earnings. As part of its normal business operations, Idaho Power purchases coal and natural gas in the open market or under short-term, long-term, or variable-priced contracts. Market prices for coal and natural gas are influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Most of Idaho Power's coal supply arrangements are for coal originating in Wyoming and any disruption of coal production in, or transportation from, that region may cause Idaho Power to incur additional fuel supply costs or use alternative generation sources or wholesale market power purchases. Natural gas transportation to Idaho Power's natural gas plants is limited to one primary pipeline, presenting a heightened possibility of supply disruptions. Idaho Power is also exposed to the risk that its counterparties to fuel purchase arrangements will default on their obligations, causing Idaho Power to seek alternative sources of fuel or rely on other generation sources or wholesale market power purchases. Idaho Power may not be able to fully recover these increased costs through rates or its power cost adjustment mechanisms, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, accidents and workforce safety matters, release of hazardous or toxic substances into the air or water, the failure of a hydroelectric facility, the loss of cost-effective disposal options for solid waste, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of those facilities could result in reduced customer satisfaction and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses for alternative fuels or wholesale market power purchases. Accidents, fires, explosions, system damage or dysfunction, and other unplanned events related to Idaho Power's infrastructure may expose Idaho Power to claims for personal injury or property damage. Further, the transmission system in Idaho Power's service territory is constrained, limiting the ability to transmit electric energy within the service territory and access electric energy from outside the service territory during high-load periods. The transmission constraints could result in failure to provide reliable service to customers and the inability to deliver energy from generating facilities to the power grid, or not being able to access lower cost sources of electric energy, which could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

Volatility in the financial markets, or denial of regulatory authority to issue debt or equity securities, may negatively affect IDACORP's and Idaho Power's ability to access capital and/or increase their cost of borrowing, or result in losses on investments. IDACORP and Idaho Power require liquidity to pay operating expenses and principal of, and interest on, debt and to finance capital expenditures not satisfied by cash flows from operations. Financial markets have in recent years experienced extreme volatility and disruption, most recently as a result of the European sovereign debt situation, generally resulting in a decrease in the availability of liquidity and credit for borrowers. In a volatile credit environment, Idaho Power may be unable to issue long-term indebtedness at reasonable interest rates or at all, one or more of the participating banks in IDACORP's and Idaho Power's credit facilities may default on their obligations to make loans under, or may withdraw from, the credit facilities, or IDACORP's and Idaho Power's access to capital may otherwise be inhibited. In addition, at times Idaho Power has a relatively large balance of short-term investments. Volatility in the financial markets may result in a lack of liquidity for short-term investments and declines in value of some investments. The occurrence of any of these events could affect Idaho Power's ability to execute its business plan and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. Further, Idaho Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations. Notably, without additional approval from those commissions, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

A downgrade in IDACORP's and Idaho Power's credit ratings could affect the companies' ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Access to capital markets is important to IDACORP's and Idaho Power's ability to operate and to complete capital projects, including its planned transmission projects. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power, and these ratings impact access to, and the cost of, borrowing. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source of short-term financing. Downgrades of IDACORP's or Idaho Power's credit ratings, or those affecting relationship banks, could limit the companies' ability to access capital, including commercial paper markets, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Idaho Power's risk management policy and programs relating to economically hedging power and gas exposures, financial and interest rate risk, and counterparty creditworthiness may not always perform as intended, and as a result IDACORP and Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities, and enters into financial hedges. IDACORP and Idaho Power could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. The derivative instruments might not offset the underlying exposure being mitigated as intended, due to pricing inefficiencies or other terms of the derivative instruments, and any such failure to mitigate exposure could result in financial losses. Further, forecasts of future fuel needs and loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. As a result, risk management actions may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power could be subject to penalties and operational changes if it violates mandatory reliability and security requirements, which could adversely impact IDACORP's and Idaho Power's results of operations and financial condition. As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Further, Idaho Power has received in recent years notices of violations from, and self-reported reliability standard compliance issues to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council, and has several matters pending. Potential monetary and non-monetary penalties for a violation of Federal Energy Regulatory Commission regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power could have a negative effect on its and IDACORP's results of operations and financial condition.

Federally mandated purchases of power from PURPA power projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect Idaho Power's and IDACORP's results of operations and financial condition. An abundance of intermittent, non-dispatchable wind power generation at times when Idaho Power has available lower-cost resources to meet load demands has an impact on the operation of Idaho Power's hydroelectric generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Wind power generated from PURPA projects, which Idaho Power is generally obligated to purchase regardless of the then-current load demand or wholesale energy market prices, increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, increasing power purchase costs. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its operational costs will increase as a result of its efforts to integrate intermittent, non-dispatchable power from a large number of PURPA power projects. Recent efforts to obtain further authorization to curtail certain intermittent power sources during light-load times have been unsuccessful. Idaho Power anticipates that costs will escalate as the volume of wind and other intermittent power on Idaho Power's system increases, which may negatively affect IDACORP's and Idaho Power's results of operations and financial condition.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs and funding obligations could adversely affect IDACORP's and Idaho Power's financial condition and results of operations - primarily cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power's plan costs and funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are inherently uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including timing of retirements or changes in life expectancy assumptions, may also increase Idaho Power's plan costs and funding requirements. Future pension funding requirements and the timing of funding payments are also subject to the impacts of changes in legislation. Depending on the timing of contributions to the plans and Idaho Power's ability to recover costs through rates, cash contributions to the plans could reduce the cash available for operating activities. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

As a holding company, IDACORP does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments. IDACORP is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. IDACORP's subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other payments. The ability of IDACORP's subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which may reduce or cease payment of dividends at any time. See Item 5 - "Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities" in this report for a further description of restrictions on IDACORP's and Idaho Power's payment of dividends.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP's or Idaho Power's financial condition and results of operations. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. The companies' tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation, and employment-related taxes and ongoing issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by taxing authorities. In recent years, tax settlements, as well as state regulatory mechanisms with tax-related provisions (such as Idaho Power's December 2011 settlement with the Idaho Public Utilities Commission), have significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of ongoing and future income tax proceedings, or the state public utility commissions' treatment of those tax outcomes, could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could negatively affect IDACORP's and Idaho Power's earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho Power anticipate or request from applicable state regulatory commissions, which could have a negative effect on their financial condition and results of operations.

Employee workforce factors, including the impacts of an aging workforce with specialized utility-specific functions, could increase costs and adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, an aging workforce, and impacts of efforts to organize the workforce. A unionization attempt that was launched in late-2012 failed, but does not prevent future unionization attempts. Idaho Power's operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, and generation plant operators, require extensive, specialized training. Idaho Power expects that a significant portion of its skilled workforce will be retiring within the current decade, which will require Idaho Power to attract, train, and retain skilled workers to prevent a loss of institutional knowledge and avoid a skills gap. Without a skilled workforce, Idaho Power's ability to provide quality service to its customers and meet regulatory requirements will be challenging, which could negatively affect earnings. The costs associated with attracting and retaining appropriately qualified employees to replace an aging and skilled workforce could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims. From time to time in the normal course of business IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other relief. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. As an example, over the past decade Idaho Power has been a party to proceedings relating to high prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001, which caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the Federal Energy Regulatory Commission to initiate its own investigations. While Idaho Power has largely disposed of direct claims in those proceedings, the settlements and associated Federal Energy Regulatory Commission orders did not eliminate the potential for speculative "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. Idaho Power's settlement payments in those proceedings have been relatively small to date, but the legal costs of defending the claims over the past decade have been substantial. In recent years, Idaho Power has also been a party to legal proceedings advanced by private parties relating to alleged violations of environmental laws at coal-fired plants. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have a negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their business practices and procedures, which could also have a negative affect on their financial positions and results of operations.

Acts or threats of terrorism, cyber attacks, security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations, or the businesses of third parties, could negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power's generation and transmission facilities are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed "critical infrastructure," in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, national public health or safety, or any combination of those matters. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power and by delaying the development and construction of new generating and transmission facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure Idaho Power's assets, and could further adversely affect Idaho Power's operations by contributing to disruption of supplies and markets for natural gas or coal used to fuel gas- or coal-fired power plants.

In the normal course of business, Idaho Power collects, processes, and retains sensitive and confidential customer and proprietary information, and operates systems that directly impact the availability of electric power and the transmission of electric power in the electric grid. Despite the security measures in place, Idaho Power's facilities and systems could be vulnerable to security breaches, data leakage, or other similar events that could interrupt operations, exposing Idaho Power to liability. Those breaches and events may result from acts of Idaho Power employees, contractors, or third parties. If Idaho Power's information technology and security systems were to fail or be breached and Idaho Power were unable to recover the systems and/or data in a timely manner, Idaho Power may be unable to fulfill critical business functions. In such case, confidential and proprietary business, employee, or customer information could be compromised, exposing Idaho Power to liability and causing business disruptions, which could negatively affect Idaho Power's business operations and IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's business and operations may be adversely affected by its inability to successfully implement current information technology projects. Idaho Power is currently undertaking several multi-year company-wide information technology solution upgrades intended to replace existing software and systems. These projects include a new customer information system, Idaho Power's SmartGrid initiative, and migration from Idaho Power's existing mainframe system to an open system. Idaho Power is also implementing systems to augment and improve its ability to pinpoint the sources of electric system outages, respond to them more quickly, and focus repair efforts. Implementation of these information systems and technology solutions is complex, expensive, and time consuming. If Idaho Power does not successfully implement the new systems and processes, or if the systems do not operate as intended or cause data or operational errors, it could result in substantial disruptions to Idaho Power's business, which could have a material adverse effect on IDACORP's and Idaho Power's results of operations and financial condition.

Changes in accounting standards or Securities and Exchange Commission rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board and the Securities and Exchange Commission may make changes to accounting standards that impact presentation and disclosures of financial condition and results of operations. Further, new accounting orders issued by the Federal Energy Regulatory Commission could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles to reflect the impact of regulatory decisions in its financial statements and to defer certain costs as regulatory assets until those costs are collected in rates, and to defer some items as regulatory liabilities. Idaho Power expects to recover its regulatory assets from customers through rates but recovery is subject to review by the regulatory bodies. If recovery of these amounts ceases to be probable, if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Any of these circumstances could result in write-offs and have a material effect on IDACORP's and Idaho Power's reported financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission, and distribution facilities, as well as coal assets that support one of its coal-fired generation plants. In addition to these physical assets, Idaho Power has rights-of-way and water rights that enable it to utilize its facilities. Idaho Power's system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, three natural gas-fired plants located in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. As of December 31, 2012, the system also includes approximately 4,851 pole miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 228 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 26,764 pole miles of distribution lines.

Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power's hydroelectric projects is discussed in Item 7 - "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects." Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are listed below.

Project	Nameplate Capacity (kW)[1]	License Expiration
Hydroelectric Projects:		
Properties Subject to Federal Licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	12,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,166,900	2005 [2]
Swan Falls	27,170	2042
American Falls	92,340	2025
Cascade	12,420	2031
Milner	59,448	2038
Twin Falls	52,897	2040
Other Hydroelectric:		
Clear Lakes - Thousand Springs	11,300	
Total Hydroelectric	1,709,045	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired) [3]	770,501	
Valmy (coal-fired) [3]	283,500	
Boardman (coal-fired) [3][4]	64,200	
Danskin (gas-fired)	270,900	
Langley Gulch (gas-fired)	318,452	
Bennett Mountain (gas-fired)	172,800	
Salmon (diesel-internal combustion)	5,000	
Total Steam and Other	1,885,353	
Total Generation	3,594,398	

(1) Actual generation capacity from a facility may be greater or less than the rated nameplate generation capacity.

(2) Licensed on an annual basis while the application for a new multi-year license is pending.

(3) Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.

(4) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations by December 31, 2020.

Idaho Power's headquarters are located in Boise, Idaho, consisting of approximately 334,000 square feet of owned office space throughout the corporate campus. Idaho Power also leases approximately 84,000 square feet of office space in Boise for corporate, engineering, and administrative functions, and owns and leases approximately 468,000 square feet of office, operations, and warehouse space in various other locations throughout Idaho Power's service territory in Idaho and Oregon, excluding supportive offices located at generation facilities.

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Substantially all of Idaho Power's property is subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. Idaho Power's property is subject to minor defects common to properties of such size and character that do not materially impair the value to, or the use by, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

IERCo owns a one-third interest in BCC and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant. Ida-West holds 50 percent interests in nine operating hydroelectric plants with a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – "Contingencies" to IDACORP's and Idaho Power's consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP's common stock, without par value, is traded on the New York Stock Exchange (NYSE). On February 15, 2013, there were 11,898 holders of record of IDACORP common stock and the closing stock price was $46.73 per share. The outstanding shares of Idaho Power's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

The amount and timing of dividends paid on IDACORP's common stock are within the sole discretion of IDACORP's board of directors. The board of directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deem relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

A covenant under IDACORP's credit facility and Idaho Power's credit facility described in Part II, Item 7 - "MD&A – Liquidity and Capital Resources - Financing Programs – Credit Facilities" requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined in the respective credit facilities, of no more than 65 percent at the end of each fiscal quarter.

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 ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or Idaho Power's Code of Conduct. At December 31, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $889 million and $794 million, respectively, at December 31, 2012. Idaho Power must obtain approval of the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding. IDACORP and Idaho Power paid dividends of $69 million, $60 million, and $58 million in 2012, 2011, and 2010, respectively.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to $0.33 per share of IDACORP common stock, from the prior dividend amount of $0.30 per share of IDACORP common stock. On September 20, 2012, IDACORP's board of directors voted to increase the quarterly dividend, commencing with the dividend payable on November 30, 2012, to $0.38 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 - "Common Stock" to the consolidated financial statements included in this report.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2012 and 2011 as reported by the NYSE.

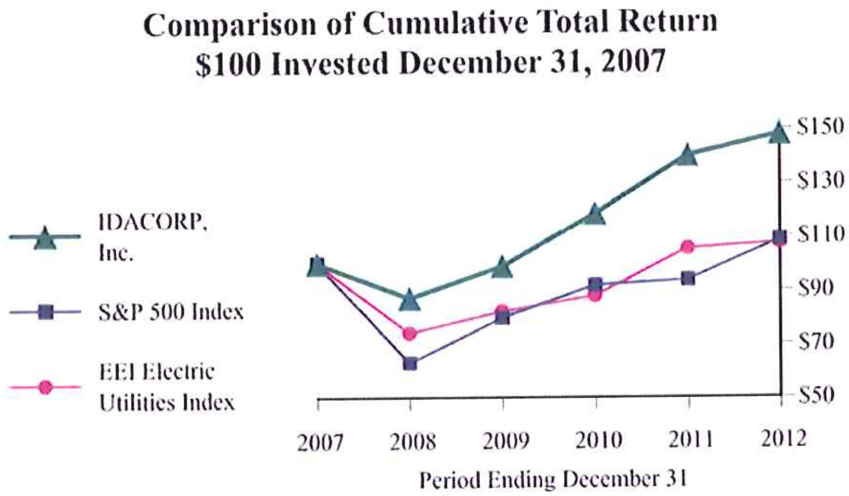
	2012			2011		
Quarter	**High**	**Low**	**Dividends paid per share**	**High**	**Low**	**Dividends paid per share**
1st	$ 42.89	$ 39.66	$ 0.33	$ 38.72	$ 36.14	$ 0.30
2nd	42.22	38.17	0.33	40.38	37.65	0.30
3rd	44.03	41.00	0.33	40.71	33.88	0.30
4th	45.67	40.18	0.38	42.66	37.26	0.30

During 2011, 2010, and 2009, Idaho Power paid dividends to its parent, IDACORP, in the amounts shown in Idaho Power's Consolidated Statements of Retained Earnings included in this report.

IDACORP, Inc. did not repurchase any shares of its common stock during the fourth quarter of 2012.

Performance Graph

The following performance graph shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index, and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on December 31, 2007, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.



Source: Bloomberg and EEI

	2007	2008	2009	2010	2011	2012
IDACORP	$ 100.00	$ 86.99	$ 98.78	$ 118.39	$ 140.00	$ 147.94
S&P 500	100.00	63.01	79.69	91.71	93.62	108.59
EEI Electric Utilities Index	100.00	74.10	82.03	87.80	105.35	107.55

The foregoing performance graph and data shall not be deemed "filed" as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and should not be deemed incorporated by reference into any other filing of IDACORP or Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars, except per share amounts)

	2012	2011	2010	2009	2008
Operating revenues	$1,080,662	$1,026,756	$1,036,029	$1,049,800	$ 960,414
Operating income	242,602	155,352	191,811	196,363	183,818
Net income attributable to IDACORP, Inc.	168,761	166,693	142,798	124,350	98,414
Diluted earnings per share from continuing operations	3.37	3.36	2.95	2.51	2.17
Dividends declared per share	1.37	1.20	1.20	1.20	1.20
Financial Condition:					
Total assets	$5,319,516	$4,960,609	$4,238,727	$4,022,845	$3,653,308
Long-term debt (including current portion)	1,537,696	1,488,614	1,419,070	1,269,979	1,168,336
Financial Statistics:					
Times interest charges earned:					
Before tax [(1)]	3.27	2.35	2.65	2.88	2.47
After tax [(2)]	2.97	2.97	2.66	2.59	2.23
Book value per share [(3)]	$ 35.07	$ 33.18	$ 31.01	$ 29.17	$ 27.76
Market-to-book ratio [(4)]	124%	128%	119%	110%	106%
Payout ratio [(5)]	41%	36%	41%	45%	55%
Return on year-end common equity [(6)]	9.6%	10.1%	9.3%	8.9%	7.6%

The financial statistics listed above are calculated in the following manner:

[(1)] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

[(2)] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

[(3)] Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

[(4)] The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (3) above.

[(5)] Dividends paid per common share divided by diluted earnings per share.

[(6)] Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power. Also refer to "Cautionary Note Regarding Forward-Looking Statements" and Part 1 - Item 1A - "Risk Factors" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP's common stock is listed and trades on the New York Stock Exchange under the trading symbol "IDA." Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power provided electric service to approximately 501,000 general business customers as of December 31, 2012. As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), which determine the rates that Idaho Power charges to its general business customers. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its Federal Energy Regulatory Commission (FERC) tariff and to provide transmission services under its FERC open access transmission tariff (OATT). Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, and to seek to earn a return on investment.

Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power's revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, availability of water for hydroelectric generation, price changes, customer usage patterns (which are affected in large part by the condition of the local economy), and the availability and price of purchased power and fuel. Idaho Power experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. IDACORP's and Idaho Power's financial condition are also affected by regulatory decisions through which Idaho Power seeks to recover its costs on a timely basis and earn an authorized return on investment, and by the ability to obtain financing through the issuance of debt and/or equity securities.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co., which is the former limited partner of, and successor by merger to, IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003. 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.

EXECUTIVE OVERVIEW

Brief Overview of 2012 Results

IDACORP's 2012 earnings per diluted share of $3.37 were one cent above its 2011 earnings per diluted share of $3.36 and reflect the impacts of general rate increases that went into effect during 2011 and 2012 and increased irrigation sales volumes. Idaho Power's 2012 return on year-end equity in the Idaho jurisdiction exceeded 10.5 percent, triggering the sharing mechanism in Idaho Power's December 2011 settlement agreement, discussed below, and resulting in a $21.8 million reduction to operating income, reflecting earnings to be shared with Idaho customers to reduce rates. For purposes of comparison, during 2011 IDACORP's earnings were significantly impacted by the recognition of $56.9 million in tax benefits relating to prior tax years. The 2011 tax benefit, combined with operating results, triggered a similar sharing mechanism in Idaho during 2011 that reduced 2011 operating income by $47.4 million. A more specific discussion of the factors influencing IDACORP's and Idaho Power's results for 2012, including a quantification of their respective impacts, is included below in this MD&A.

2012 Accomplishments and 2013 Initiatives

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. For the past several years, Idaho Power has been implementing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of Idaho Power's achievements during 2012 under its three-part business strategy include:

- commencement of the Langley Gulch power plant's commercial operation, ahead of schedule and within budget;
- continued execution of Idaho Power's purposeful regulatory strategy, which resulted in approval of Idaho Power's requests for recovery of, and a return on, Idaho Power's investment in the Langley Gulch power plant, a general rate increase in Idaho on January 1, 2012, and the issuance of an order by the IPUC pertaining to PURPA-related matters;
- continued progress toward the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects and execution of associated cost-sharing agreements with PacifiCorp and the Bonneville Power Administration (BPA);
- continued progress toward achieving IDACORP's previously adopted dividend policy; during 2012 the IDACORP Board of Directors voted to increase the quarterly dividend twice, resulting in an aggregate increase from $0.30 per share quarterly to $0.38 per share quarterly, or nearly 27 percent;
- receipt of a 30-year license from the FERC for the continued operation of the Swan Falls hydroelectric facility;
- ranking in the top quartile of the 126 largest utilities in the country for customer satisfaction in the J.D. Power and Associates 2012 Electric Utility Residential Customer Satisfaction Study;
- recognition for Highest Customer Satisfaction with Business Electric Service in the Western U.S. among Midsize Utilities in a Tie in the J.D. Power and Associates 2012 Electric Utility Business Customer Satisfaction Study of more than 90 utility brands across the U.S.; and
- ranking among the "40 Best Energy Companies" by *Public Utilities Fortnightly*.

One of management's primary goals during 2011 and 2012 was to reduce Idaho Power's regulatory lag, which results from the period of time between making an investment or incurring an expense and earning a return and recovering that investment or expense. Management focused heavily on implementation of new rates and approval of regulatory mechanisms during 2011 and 2012. As Idaho Power transitions to 2013 and into 2014 it will focus on optimizing operations and managing growth in expenses in an effort to achieve or exceed a rate of return reflective of those allowed by the IPUC and OPUC. Management anticipates that the IDACORP Board of Directors will, when appropriate, take steps during 2013 in furtherance of the dividend policy it adopted in November 2011, which provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings. Other specific matters that the companies expect will require management's focus and attention in 2013 include continued efforts toward permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects, completion and filing of the 2013 integrated resource plan (IRP), implementation of a significant new customer relations and billing system, and continued work toward federal relicensing of the Hells Canyon Complex (HCC) hydroelectric facility.

For 2013, in addition to its specific projects, Idaho Power has established a number of organizational initiatives, including the following:

- actively manage through the challenging economic environment by optimizing business practices, maintaining capital liquidity, and maintaining credit ratings;
- continue to emphasize innovative approaches to regulatory strategy;

- promote economic development through collaboration with the states of Idaho and Oregon to attract new businesses that fit Idaho Power's resource and load profile mix;
- focus on operational excellence by matching resources to customer loads, managing the impacts of environmental regulations, maintaining Idaho Power's hydroelectric base, enhancing power quality and reliability, and customer satisfaction; and
- maintain an enterprise safety culture and an effective and motivated workforce, address workforce attrition, and enhance succession planning and training programs in anticipation of a significant number of retirements in the next few years.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by regulatory, economic, and other factors, many of which are described below.

Emphasis on Regulatory Cost Recovery and Expense Management; Support from Regulatory Settlement: The price that Idaho Power is authorized to charge for its electric service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Because of the significant impact of ratemaking decisions, and in furtherance of its goal of advancing a purposeful regulatory strategy, Idaho Power has focused on timely recovery of its costs through filings with the company's regulators, and the prudent management of expenses and investments after receiving rate orders from the IPUC and OPUC. Effective implementation of Idaho Power's regulatory strategy is particularly important in a climate of slow economic recovery that continues to put pressure on regulators to limit rate increases or otherwise take actions to limit the potential adverse impact of rate increases on customers.

The number of regulatory filings and activity during the period from 2010 to 2012 exceeded historical averages, driven by Idaho Power's regulatory strategy. The rate orders Idaho Power has received in recent years and their associated mechanisms have decreased the likelihood that Idaho Power would seek rate relief through a general revenue rate case during 2013, and instead focus on optimizing business operations and processes. Particularly notable regulatory developments that have impacted or that IDACORP and Idaho Power expect will impact results, each of which is discussed in more detail under "Regulatory Matters" in this MD&A or in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, include the following:

Proceeding	Description	Amount and Timing of Rate Increase/Decrease
Idaho General Rate Case Settlement	General rate case, requesting an increase in Idaho-jurisdiction base rates	IPUC approved a $34.0 million **increase** in rates, effective January 1, 2012
Langley Gulch Power Plant	Request for recovery of and return on Idaho Power's investment in the Langley Gulch power plant, including operating costs	IPUC approved a $58.1 million **increase** in rates, effective July 1, 2012; OPUC approved a $3.0 million **increase** in rates effective October 1, 2012
Revenue Sharing	Rate adjustment pursuant to January 2010 and December 2011 settlement agreements(1)	IPUC approved a $27.1 million **decrease** in rates, effective only for the period from June 1, 2012 to May 31, 2013(1)
Oregon General Rate Case Settlement	General rate case, requesting an increase in Oregon-jurisdiction base rates	OPUC approved a $1.8 million **increase** in rates, effective March 1, 2012

(1) The rate change for the Idaho PCA was partially offset by the revenue-sharing order issued pursuant to the January 2010 and December 2011 settlement agreements. Idaho Power's revenue-sharing arrangements had two components: (a) a PCA mechanism component, which reduced net rates by $27.1 million, and (b) a pension balancing account component, which resulted in a $20.3 million net reduction to Idaho Power's pension regulatory asset (reducing Idaho customers' future obligation). Idaho Power recorded the $27.1 million revenue reduction and $20.3 million pension regulatory asset reduction in 2011.

In addition to the rate changes listed in the table above, in December 2011 the IPUC approved a settlement stipulation, separate from the Idaho general rate case settlement, that permits Idaho Power to amortize additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum 9.5 percent rate of return on year-end equity in the Idaho jurisdiction (Idaho ROE) in 2012, 2013, and 2014, subject to prescribed limits and conditions. The settlement stipulation also provides for the potential sharing between the company and customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. The specific terms of the settlement stipulation are described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. While providing no assurance that Idaho Power will obtain a 9.5 percent Idaho ROE in any of the years, IDACORP and Idaho Power believe the ability to amortize additional ADITC provides an element of earnings stability for 2013 and 2014. Because its 2012 Idaho ROE exceeded 9.5

percent, Idaho Power did not amortize additional ADITC in 2012 under the settlement stipulation. Based on the terms of the December 2011 settlement stipulation, Idaho Power recorded during 2012 a $7.2 million provision against current revenues, as a benefit to Idaho customers in the form of a future rate reduction, and an additional $14.6 million of pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future. Idaho Power recorded $47.4 million for the impact of similar sharing mechanisms in 2011.

Economic Conditions and Customer/Load Growth: When seeking to predict utility load changes for both short-term load forecasts and long-term infrastructure planning purposes, Idaho Power monitors a number of economic indicators, including employment rates, growth in customer numbers, and foreclosure rates and other housing-related data on both a national scale and within Idaho Power's service territory. Economic conditions can impact consumer demand for electricity, collectability of accounts, the volume of off-system sales, and the need to purchase power to meet demand.

Since 2008, economic conditions in Idaho Power's service territory have been relatively weak. However, a number of improvements in economic conditions have occurred over the last few months. After peaking at 10.0 percent in early 2011, the service area unemployment rate fell to 8.4 percent by the end of 2011 and reached 6.2 percent by the end of 2012, according to Idaho Department of Labor data. The housing market in Idaho Power's service territory has improved when measured by foreclosure rates and the available supply and pricing of housing. Idaho Power also continues to experience customer growth, and a number of businesses have constructed facilities in Idaho Power's service territory. For the year ended December 31, 2012, the customer growth rate in Idaho Power's service territory was approximately 1.1 percent—roughly twice the growth rate of the prior two years. However, by comparison, for the 20-year period ending in 2011 the average annual customer growth rate in Idaho Power's service territory was 2.6 percent. Idaho Power predicts that customer growth within its service territory in the next few years will be positive, though at a rate below the 20-year historical annual average.

In light of the uncertainty of the timing and pace of economic recovery in its service territory, and general underlying concerns remaining about the strength and pace of recovery of the economy and financial markets, Idaho Power continues to manage costs while executing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use. As the customer growth rate and demand have potentially stabilized, Idaho Power is transitioning from an emphasis on large capital projects, particularly generation, to an emphasis on maintaining and replacing aging assets while planning and building for the future. Idaho Power plans to control operating and maintenance and capital costs through process and project reviews and through process improvement initiatives, and by empowering employees to identify means to reduce costs, build efficiencies, and enhance individual and enterprise performance. These actions are particularly important at a time when customer growth is relatively low and new rates have been approved and implemented.

In December 2012, Idaho Power filed an application with the IPUC requesting the temporary suspension during 2013 of two demand response programs that Idaho Power had previously implemented to reduce peak-hour loads. Included was a discussion of the results of preliminary studies conducted in connection with Idaho Power's 2013 IRP, including a load and resource balance for the 2013 to 2032 period. After application of a number of assumptions, under a scenario that excludes demand response programs and power capacity from the proposed Boardman-to-Hemingway 500-kV transmission line, the peak-hour load and resource balance indicates no peak-hour load deficit until 2016, which under those assumptions the need for near-term peak-hour resources like demand response programs or new near-term supply-side resources does not exist. While these results preliminarily suggest that new generation projects are not necessary in the near-term, Idaho Power has not completed its analysis and will not have completed its analysis until the publication of its 2013 IRP in mid-2013. The 2013 IRP will describe the estimated timing of potential generation and transmission projects.

Weather Conditions and Associated Impacts: Weather and agricultural growing conditions have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy usage for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters, irrigation customers use electricity to operate irrigation pumps. For instance, the 2.6-percent increase in energy use by general business customers during 2012 compared to 2011 was largely attributable to agricultural growing conditions from April through June that required above average use of irrigation equipment. As noted above, Idaho Power also has tiered rates and seasonal rates, which contribute to increased revenues during higher-load periods, most notably the third quarter of each year when customer demand is typically at its peak. On July 12, 2012, Idaho Power achieved a record load demand of 3,245 MW. The previous record load demand was 3,214 MW, set on June 30, 2008.

Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity. The availability and volume of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, base flows in the Snake River, spring flows, rainfall, water leases and other water rights, and other weather and stream flow considerations. Idaho Power expects hydroelectric generation during 2013 to be in the range of 6.0 to 8.0 million megawatt-hours (MWh), based on reservoir storage levels and forecasted weather conditions as of the date of this report, compared to actual generation of 8.0 million MWh in 2012, 10.9 million MWh in 2011, and 7.3 million MWh in 2010. Median annual hydroelectric generation is 8.6 million MWh. When hydroelectric generation is reduced Idaho Power must rely on more expensive generation sources and purchased power; however, most of the increase in power supply costs is deferred as a regulatory asset and collected from customers through its Idaho and Oregon power cost adjustment (PCA) mechanisms described later in this MD&A. Conversely, in periods of greater hydroelectric generation most of the resulting decrease in power supply costs that typically occurs is returned to customers through the PCA mechanisms.

Where favorable hydroelectric generating conditions exist for Idaho Power, they also may be abundant for other Pacific Northwest hydroelectric facility operators, thus increasing the available supply of lower-cost power and depressing regional wholesale market prices, which impacts the revenue Idaho Power receives from off-system sales of its excess power. Conversely, when hydroelectric generating conditions are poor, wholesale market prices may be higher due to lower supply, but Idaho Power would have less surplus energy available for sale into the wholesale markets. Again, much of the adverse or favorable impact of these costs is addressed through the PCA mechanisms.

Fuel and Purchased Power Expense: In addition to hydroelectric generation and power it purchases in the wholesale markets, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's power generation capacity, the rate of expansion of alternative energy generation sources such as wind energy, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. Operation of Idaho Power's newly constructed Langley Gulch power plant has increased Idaho Power's use of natural gas as a generation fuel, and thus its exposure to volatility in natural gas prices.

Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind energy, and wholesale energy market prices. Idaho Power is obligated to purchase power from some PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss. Integration of intermittent, non-dispatchable resources (such as wind energy) into Idaho Power's portfolio also creates a number of complex operational risks and challenges that Idaho Power is working to address, including through evaluation of the results of a recent comprehensive wind integration study. Notably, integration of these sources of power into Idaho Power's portfolio does not eliminate Idaho Power's need to construct facilities and infrastructure that provide reliable power. For instance, at the time Idaho Power reached its all-time system peak demand of 3,245 MW on July 12, 2012, wind resources on Idaho Power's system, representing roughly 500 MW of capacity, were contributing only 14 MW of power due to lack of wind. Increases in federally mandated PURPA power purchases were a significant driver of increased power purchase costs during 2012 and will likely continue to push power purchase costs, and correspondingly, customer rates, higher.

The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts to Idaho Power of fluctuations in Idaho Power's power supply costs, including 100-percent of the Idaho-jurisdiction PURPA power purchase costs. Idaho Power also uses physical and financial forward contracts for both electricity and fuel in order to manage the risks relating to fuel and power price exposures.

Regulatory and Environmental Compliance Costs and Expenditures: Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits, including FERC and North American Electric Reliability Corporation (NERC) reliability requirements. Compliance with these requirements directly influences Idaho Power's operating environment and may significantly increase Idaho Power's operating costs. Further, potential monetary and non-monetary penalties for a violation of applicable laws or regulations may be substantial. Accordingly, Idaho Power has in place numerous compliance policies and initiatives, and frequently evaluates, updates, and supplements those policies and initiatives.

In particular, environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power cease operating certain power generation plants. For instance, the Boardman coal-fired power plant, in which Idaho Power owns a 10-percent interest, is scheduled to cease coal-fired operations by the end of 2020, the decision for which was driven in large part by the substantial cost of environmental controls. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade. As legislation and regulations concerning greenhouse gas emissions develop, Idaho Power assesses, when and to the extent determinable, the potential impact on the costs to operate its power generation facilities, as well as the willingness or ability of joint owners of power plants to fund any required pollution control equipment upgrades in lieu of early plant retirements. For instance, Idaho Power recently concluded cost studies and scenario analyses to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal-fired generation facilities. Idaho Power published the results of the study with its IRP update filed with the OPUC in February 2013, concluding that planned investments in environmental controls at the plants are appropriate.

Other Notable Matters and Areas of Focus

Pension Plan Funding: From 2010 to 2012 Idaho Power contributed $123 million to its defined benefit pension plan. In May 2011 the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. While Idaho Power does not anticipate that any cash contributions will be required in 2013, it does expect to make additional significant cash contributions to the pension plan in the future. Idaho Power defers pension costs related to its Idaho jurisdiction until those costs are recovered through rates. While the IPUC's authorization to increase the annual recovery has mitigated in large part the adverse impacts of the contributions, the magnitude of the contributions relative to the annual cost recovery creates a lag between the timing of expenditures and their recovery, which impacts IDACORP's and Idaho Power's cash flows. While Idaho Power does not, as of the date of this report, have an expected date to request from regulators an additional increase in cost recovery, it may determine to do so if future contributions continue to be similar in magnitude to those made in recent years.

Water Management and Relicensing of the Hells Canyon Hydroelectric Project: Because of Idaho Power's reliance on stream flow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for use at its hydroelectric projects. Also, Idaho Power is involved in renewing federal licenses for the HCC, its largest hydroelectric generation source, and recently received a 30-year license renewal from the FERC for its Swan Falls hydroelectric project. Relicensing involves numerous environmental issues and substantial costs. Idaho Power is working with the states of Idaho and Oregon, regulatory authorities, and interested parties to address concerns and take appropriate measures relating to the relicensing of the HCC. However, given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial.

Transmission Projects: Idaho Power continues to focus on expansion of its transmission system in an effort to improve system reliability and access to wholesale markets. Its most notable projects in progress include the proposed Boardman-to-Hemingway and Gateway West 500-kV transmission projects. In January 2012, Idaho Power entered into cost-sharing arrangements with third parties for the permitting phases of both projects. Construction of these projects cannot commence until all federal, state, and local regulatory requirements are met. Based on Idaho Power's assessment of the status and future milestones for the Boardman-to-Hemingway project, Idaho Power has determined that an in-service date prior to 2018 is unlikely.

Summary of 2012 Financial Results

The following is a summary of Idaho Power's net income, net income attributable to IDACORP, and IDACORP's earnings per diluted share for the years ended December 31, 2012, 2011, and 2010 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2012	2011	2010
Idaho Power net income	$ 168,168	$ 164,750	$ 140,634
Net income attributable to IDACORP, Inc.	$ 168,761	$ 166,693	$ 142,798
Average outstanding shares – diluted (000's)	50,010	49,558	48,340
IDACORP, Inc. earnings per diluted share	$ 3.37	$ 3.36	$ 2.95

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for 2011 to 2012 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2011			**$ 166.7**
Change in Idaho Power net income before taxes:			
Rate and other regulatory changes, including power cost adjustment, pension expense recovery, and fixed cost adjustment mechanisms		$ 65.2	
Changes in sales volumes		16.1	
Change in payroll-related expenses		(6.8)	
Change in pension expense funded through rate increases		(5.1)	
Increased depreciation expense, property tax, and other		(8.7)	
Increase in Idaho Power operating income prior to sharing mechanisms		60.7	
Greater pension expense in 2011 than in 2012 as a result of sharing mechanisms	5.7		
Greater revenue sharing in 2011 than in 2012	19.9		
Increase in operating income as a result of sharing mechanisms		25.6	
Increase in Idaho Power operating income		86.3	
Decrease in allowance for funds used during construction (AFUDC)		(4.5)	
Other net decreases		(1.0)	
Change in income tax expense		(22.1)	
Increase in Idaho Power net income prior to effects of tax method changes and related examination settlements		58.7	
Net decrease in tax method changes and related examination settlements		(55.3)	
Total increase in Idaho Power net income			3.4
Other net decreases (net of tax)			(1.3)
Net income attributable to IDACORP, Inc. - December 31, 2012			**$ 168.8**

IDACORP's net income was $168.8 million in 2012, an increase of $2.1 million compared to 2011. IDACORP's 2012 results reflect an $86.3 million increase in operating income at Idaho Power compared to 2011, which was largely driven by increases in rates and higher irrigation sales volumes. This increase was substantially offset by the net impact of a tax method change and favorable IRS examination settlements recorded in 2011.

General rate increases implemented in the first quarter of 2012, a July 2012 rate increase related to Idaho Power's new Langley Gulch power plant, and other rate changes combined to increase operating income by $65.2 million when compared to 2011. Higher sales volumes, driven primarily by a warmer, drier spring in 2012 that caused significant increases in irrigation usage when compared with the prior year, increased operating income by $16.1 million. As a result of an IRS examination settlement reached in 2011, Idaho Power recognized approximately $56.9 million of previously unrecognized tax benefits related to a uniform capitalization method agreement with the IRS for tax years 2009 and prior.

As a result of the impact on 2012 earnings of the rate and sales volume increases described above, Idaho Power recorded a total of $21.8 million related to a December 2011 settlement agreement with the IPUC, which required sharing with customers of a portion of 2012 Idaho-jurisdiction earnings exceeding a specified return on year-end equity. Of the total, $14.6 million was recorded as additional pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will need to be collected from customers in the future, and $7.2 million was recorded as a provision against current revenues to be refunded to customers through a future rate reduction. In 2011, Idaho Power recorded $20.3 million of additional pension expense and a $27.1 million provision against revenues to be refunded to customers under similar agreements. The table below summarizes the effect of the sharing mechanisms on operating income between 2012 and 2011.

Effect of Sharing on Operating Income

	2012	2011	Variance
Provision against current revenue as a result of sharing	$ (7.2)	$ (27.1)	$ 19.9
Additional pension expense funded through sharing	(14.6)	(20.3)	5.7
Total	$ (21.8)	$ (47.4)	$ 25.6

Key Operating and Financial Metrics for 2013

IDACORP's and Idaho Power's outlook for 2013 full year metrics as of the date of this report are as follows:

	2013 Estimate	2012 Actual
Idaho Power Operating & Maintenance Expense (millions)	$340-$350	$ 349
Idaho Power Additional Amortization of ADITC (millions)	Less than $5	None
Idaho Power Capital Expenditures, excluding AFUDC (millions)	$245-$255	$ 228
Idaho Power Hydroelectric Generation (million MWh)	6.0-8.0	8.0

The estimated hydroelectric generation range is based on reservoir storage levels and forecasted weather conditions as of the date of this report.

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and Idaho Power's earnings during the year ended December 31, 2012. In this analysis, the results for 2012 are compared to 2011 and the results for 2011 are compared to 2010.

Megawatt-hours (MWh) and dollar amounts are in thousands unless otherwise indicated.

Utility Operations

The table below presents Idaho Power's energy sales, in MWh, and supply for the last three years.

	Year Ended December 31,		
	2012	2011	2010
General business sales	14,085	13,734	13,513
Off-system sales	2,183	3,635	1,982
Total energy sales	16,268	17,369	15,495
Hydroelectric generation	7,956	10,937	7,344
Coal generation	5,227	4,820	6,864
Natural gas and other generation	676	138	160
Total system generation	13,859	15,895	14,368
Purchased power	3,670	2,751	2,401
Line losses	(1,261)	(1,277)	(1,274)
Total energy supply	16,268	17,369	15,495

Sales Volume and Generation: In 2012, general business sales volume increased by 0.4 million MWh, mostly related to increased irrigation customer usage compared to the prior year. Off-system sales volume decreased by 1.5 million MWh in 2012 as decreases in output from hydroelectric resources and a small increase in customer load decreased surplus power available for sale.

Hydroelectric generation comprised 57 percent of Idaho Power's total system generation during 2012. Hydroelectric generation in 2012 was 93 percent of the annual median generation of 8.6 million MWh, which is based on hydrologic conditions for the period 1928 through 2011 and adjusted to reflect the current level of water resource development. The 3.0 million MWh decrease in hydroelectric generation in 2012 compared to 2011 was primarily due to lower than normal hydroelectric generating conditions. The 3.6 million MWh increase in hydroelectric generation in 2011 compared to 2010 was due largely to favorable hydroelectric generating conditions.

The decrease in hydroelectric generation during 2012 led to an increased utilization of coal-fired and natural-gas fired generation. The commencement of operations of the Langley Gulch natural gas-fired power plant in the summer of 2012 allowed for less reliance on purchased power to replace the decreased hydroelectric generation.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. During 2012, 2011, and 2010, to reduce the magnitude of peak demands, Idaho Power utilized a number of demand response and energy efficiency programs. On July 12, 2012, Idaho Power achieved a record load demand of 3,245 MW. The highest winter peak demand of 2,527 MW was set on December 10, 2009. During these and other similar heavy load periods, Idaho Power's system is fully committed to serve loads and meet required operating reserves. When loads exceed Idaho Power's generation capacity, Idaho Power must rely on power obtained through purchase contracts (from which power may not be available when needed if the source is intermittent power such as wind) and may be required to purchase power in the wholesale energy spot market.

General Business Revenues: The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the past three years.

	Year Ended December 31,		
	2012	2011	2010
Revenue			
Residential	$ 431,555	$ 405,982	$ 400,607
Commercial	241,519	220,962	231,440
Industrial	145,054	140,701	138,394
Irrigation	137,424	104,635	110,555
Total	955,552	872,280	880,996
Provision for sharing	(7,151)	(27,099)	—
Deferred revenues [1]	(10,636)	(10,636)	(10,625)
Total general business revenues	$ 937,765	$ 834,545	$ 870,371
MWh			
Residential	5,039	5,146	4,967
Commercial	3,865	3,815	3,763
Industrial	3,133	3,100	3,076
Irrigation	2,048	1,673	1,707
Total	14,085	13,734	13,513
Customers at year-end			
Residential	416,020	411,487	408,754
Commercial	65,920	65,226	64,647
Industrial	119	121	125
Irrigation	19,045	18,736	18,547
Total	501,104	495,570	492,073

[1] As part of its January 30, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the HCC relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power expects to collect approximately $10.7 million annually in the Idaho jurisdiction, but will defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service.

Changes in rates and changes in customer demand are the primary causes of fluctuations in general business revenue. The table below presents the most significant rate increases and decreases, shown on an annualized basis, that impacted revenues over the last three years.

Description	Effective Date	Estimated Annualized $ Impact (millions)
2010 Idaho settlement agreement	6/1/2010	89
2010 Idaho PCA	6/1/2010	(147)
2010 Idaho pension expense recovery	6/1/2010	5
2011 Idaho PCA	6/1/2011	(40)
2011 Idaho pension expense recovery	6/1/2011	12
2011 Idaho general rate case settlement agreement	1/1/2012	34
2012 Idaho PCA	6/1/2012	43
2012 Idaho non-AMI meter depreciation	6/1/2012	(11)
2012 Idaho Langley Gulch	7/1/2012	58
2012 Oregon Langley Gulch	10/1/2012	3

The primary influences on customer demand are weather and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Precipitation levels during the agricultural growing season affect sales to customers who use electricity to operate irrigation pumps, with increased precipitation reducing electricity usage. Rates are also seasonally adjusted and based on a tiered rate structure that provides for higher rates during peak load periods. These seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings. Boise, Idaho weather-related information for the last three years is included in the table that follows.

	Year Ended December 31,			
	2012	2011	2010	Normal
Heating degree-days [(1)]	4,723	5,554	5,078	5,514
Cooling degree-days [(1)]	1,274	1,076	914	942

[(1)] Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day.

General Business Revenues - 2012 Compared to 2011: General business revenue increased $103.2 million in 2012 compared to 2011. The factors affecting general business revenues are discussed below.

- Rates. Rate changes, including those shown in the table above, combined to increase general business revenue by $73.5 million in 2012 compared to 2011. The revenue impact of several of these rate changes was directly offset by associated changes in operating expenses. For example, Idaho-jurisdiction pension expense recovery rate changes were fully offset by increased pension expense.

- Sharing. A part of the increase in 2012 revenue resulted from revenue sharing mechanisms associated with two Idaho regulatory agreements that provide for the sharing of Idaho-jurisdiction earnings exceeding a specified Idaho ROE. The amount to be shared through future rate reduction is recorded as a current reduction to general business revenue. Reductions of $7.2 million and $27.1 million were recorded in 2012 and 2011, respectively, resulting in a net increase to general business revenue of $19.9 million in 2012. The smaller amount recorded in 2012 when compared with the prior year is partially due to changes in the terms of the mechanism in place each year, described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

- Usage. For 2012, higher summer usage per customer increased general business revenue $13.7 million compared to 2011. Irrigation usage per customer was 20.9 percent higher for 2012 when compared with 2011 due to agricultural growing conditions, including warm temperatures that allowed for the earlier planting of crops, and lower relative springtime precipitation, which resulted in greater electricity use to operate irrigation pumps.

- Customers. Termination of service to Hoku Materials, Inc. (Hoku) during 2012 under an electric service agreement, offset by only moderate customer growth, decreased general business revenues by $3.9 million. Customer growth from 2011 to 2012 was 1.1 percent.

  In March 2009, the IPUC approved an electric service agreement between Idaho Power and Hoku, to provide electric service to Hoku's polysilicon production facility then under construction in Idaho. The initial term of the agreement was four years beginning December 1, 2009, with a maximum demand obligation during the initial term of 82 MW. In connection with an overdue invoice for electric service, in February 2012 Idaho Power, Hoku, and the IPUC Staff filed with the IPUC a settlement stipulation to amend the electric service agreement, and on March 15, 2012, the IPUC approved the stipulation revising the contract. As a result of Hoku's failure to remain timely in payments under the revised agreement, Idaho Power terminated its provision of electric service under the revised agreement in May 2012. Idaho Power applied a $2 million deposit to Hoku's April, May, and June 2012 invoices under the revised agreement and fully exhausted the deposit required by the revised agreement. For full year 2012 and prior to termination of service, Idaho Power had anticipated contract payments of $5.4 million that are unaffected by the PCA mechanism and $6.8 million of revenues that are affected by and flow through the PCA mechanism, for a total of $12.2 million. As a result of termination of service and non-payment, Idaho Power recognized $6.6 million of full year 2012 revenues that are unaffected by the PCA mechanism and no revenues that are affected by and flow through the PCA mechanism. The impact of non-payment and associated decreases in revenue on 2012 net income was tempered in part by a decrease in costs Idaho Power would have incurred in connection with the provision of service to Hoku and the impact of the PCA mechanism.

General Business Revenues - 2011 Compared to 2010: General business revenue decreased $35.8 million in 2011 compared to 2010. The factors affecting general business revenues are discussed below.

- Rates. Rate changes noted in the table above combined to reduce general business revenue by $38.8 million in 2011 as compared to 2010. The $10.5 million decline in revenue from commercial customers in 2011 relative to 2010, notwithstanding an increase in usage, was largely due to the disproportionate impact of the PCA rate reductions that went into effect in 2010 and 2011. Commercial customer rates are typically subject to a greater adjustment when PCA rates increase or decrease.

- Sharing. Much of the decrease in 2011 revenue resulted from revenue sharing mechanisms associated with Idaho regulatory agreements that provide for the sharing of Idaho-jurisdiction earnings exceeding a specified Idaho ROE. The amount shared through rate reduction was recorded as a reduction to general business revenue. A reduction of $27.1 million was recorded in 2011. No such amount was recorded in 2010.

- Usage. Higher usage per customer in 2011 increased general business revenue $13.5 million compared to 2010. The increase was due primarily to colder first quarter temperatures, which increased power demand for residential heating purposes, as well as a 17.7 percent increase in cooling degree-days during the year, which increased power demand for air conditioning purposes. This increase was partially offset by a 2.3 percent decrease in irrigation usage resulting from the cooler spring weather and the timing and level of precipitation during the second quarter of 2011.

- Customers. Changes related to the Hoku contract discussed above, along with a small increase in customer count, increased general business revenues by $16.6 million. Customer growth from 2010 to 2011 was 0.7 percent.

Off-System Sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Revenue	$ 61,534	$ 101,602	$ 78,133
MWh sold	2,183	3,635	1,982
Revenue per MWh	$ 28.19	$ 27.95	$ 39.42

Off-System Sales - 2012 Compared to 2011: Off-system sales revenue decreased by $40.1 million, or 39 percent, in 2012 as compared to 2011, as a result of lower volumes. Sales volumes decreased by 40 percent due to lower output from hydroelectric plants (as a result of less favorable snow pack and spring season run-off) and a small increase in load needs when compared with 2011.

Off-System Sales - 2011 Compared to 2010: Off-system sales revenue increased $23.5 million, or 30 percent, in 2011 as compared to 2010. Sales volumes nearly doubled, as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. This increase was partially offset by a 29 percent decrease in average prices due in part to abundant hydroelectric generation in the region.

Other Revenues: The table below presents the components of other revenues for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Transmission services, facility rental and other	$ 50,126	$ 48,918	$ 40,364
Energy efficiency	27,300	37,663	44,184
Total	$ 77,426	$ 86,581	$ 84,548

Other Revenues - 2012 Compared to 2011: Other revenues decreased $9.2 million in 2012 as compared to 2011, mainly due to:

- a decrease in energy efficiency revenues of $10.4 million, primarily due to demand response incentive payments to customers, which had been treated as an energy efficiency expense and recovered through the energy efficiency rider in 2011 and prior, were recorded as purchased power expense and recovered through the PCA mechanism during 2012, as discussed in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report; and
- an increase of $1.7 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2011 and October 1, 2012.

Energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected.

Other Revenues - 2011 Compared to 2010: Other revenues increased $2.0 million in 2011 as compared to 2010, mainly due to:

- an increase of $7.4 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases; and
- a decrease in energy efficiency revenues of $6.5 million, due in part to an IPUC order that moved custom efficiency payments to a regulatory asset to be amortized over time and recovered through general rate cases rather than through the energy efficiency rider. The remaining decrease relates to lower customer incentives paid versus the prior year.

Purchased Power: The table below presents Idaho Power's purchased power expenses and volumes for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Expense			
PURPA contracts	$ 117,618	$ 90,251	$ 56,022
Other purchased power (including wheeling)	79,317	73,085	87,747
Total purchased power expense	$ 196,935	$ 163,336	$ 143,769
MWh purchased			
PURPA contracts	1,961	1,495	910
Other purchased power	1,709	1,256	1,491
Total MWh purchased	3,670	2,751	2,401
Cost per MWh from PURPA contracts	$ 59.98	$ 60.36	$ 61.56
Cost per MWh from other sources	$ 46.41	$ 58.19	$ 58.85
Weighted average - all sources	$ 53.66	$ 59.37	$ 59.88

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase more power during heavy load periods, which is higher priced energy, than during light load periods, which is lower priced energy, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Also, in accordance with Idaho Power's risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transaction prices.

Purchased Power - 2012 Compared to 2011: Purchased power expense increased $33.6 million, or 21 percent, in 2012 as compared to 2011, principally due to additional PURPA wind generation that came on-line and less favorable hydroelectric generating conditions. MWh purchased through PURPA contracts increased 31 percent, contributing to a $27.4 million increase in PURPA power purchase expense in 2012 compared to 2011, while MWh purchased through other sources increased 36 percent. Overall MWh purchases increased due to less favorable hydroelectric generating conditions decreasing Idaho Power's volume of self-generated power. The increase in MWh purchased was partially offset by a reduction in expense per MWh purchased. Average wholesale electricity prices were lower in 2012 relative to 2011 as a result of lower natural gas prices in the region, which reduced generation costs and, correspondingly, power prices. In addition, $14.5 million of demand response program charges were recorded as purchased power expense in 2012. These costs had been treated as an energy efficiency expense and recovered through the energy efficiency rider in 2011 and prior.

Purchased Power - 2011 Compared to 2010: Purchased power expense increased $19.6 million, or 14 percent, in 2011 as compared to 2010. This increase was driven by MWh purchased from PURPA contracts, which increased 64 percent due to new PURPA wind generation facilities coming on-line. The increase was partially offset by reduced wholesale market purchases resulted from Idaho Power's above average hydroelectric generation in 2011, and continued reliance on financial hedges to mitigate potential changes in forecasted hydroelectric conditions. Wholesale market purchases were also down due to lower system loads resulting from relatively mild weather.

Fuel Expense: Idaho Power's fuel expenses and generation at its thermal generating plants for the last three years are included in the table below.

	Year Ended December 31,		
	2012	**2011**	**2010**
Expense			
Coal	$ 134,501	$ 119,845	$ 146,927
Natural gas and other	24,912	11,697	12,746
Total fuel expense	$ 159,413	$ 131,542	$ 159,673
MWh generated			
Coal	5,227	4,820	6,864
Natural gas and other	676	138	160
Total MWh generated	5,903	4,958	7,024
Cost per MWh			
Coal	$ 25.73	$ 24.86	$ 21.41
Natural gas and other	36.85	84.76	79.66
Weighted average, all sources	27.01	26.53	22.73

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh (such as the cost per MWh for natural gas and other in 2012 compared to 2011 and 2010) are noticeably impacted by these fixed charges when generation output is substantially different between the two periods.

Fuel Expense - 2012 Compared to 2011: In 2012, fuel expense increased $27.9 million, or 21 percent, compared to 2011, due to higher output at the coal-fired power plants and at the Langley Gulch plant, which came on-line during the summer of 2012. The output at the coal-fired plants was up 0.4 million MWh, or 8 percent, in 2012 compared to 2011. The increased dispatch was primarily caused by lower hydroelectric generation in 2012 than in 2011.

Fuel Expense - 2011 Compared to 2010: In 2011, fuel expense decreased $28.1 million, or 18 percent, compared to 2010 due to lower generation at Idaho Power's thermal plants. The output at these plants was down 2.0 million MWh, or 30 percent in 2011 compared to 2010. The reduced dispatch was primarily caused by lower regional power prices due to higher regional hydroelectric and wind generation. The impact of lower thermal generation was partially offset by higher coal prices. During parts of 2010, the Bridger and Valmy generating plants received fuel from prior lower-cost contracts.

PCA Mechanisms: Idaho Power's power supply costs can vary significantly from year to year, primarily because of the impacts of weather, system loads, and commodity markets. To address the volatility of power supply costs, in addition to its hedging program Idaho Power has PCA mechanisms for both the Idaho and Oregon jurisdictions. These mechanisms allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. Because of these mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers, resulting in fluctuations in operating cash flows from year to year. PCA expense represents the effects of the Idaho and Oregon PCA mechanisms. The table below presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2012	**2011**	**2010**
Idaho power supply cost (deferral) accrual	$ (45,064)	$ 27,768	$ (14,324)
Oregon power supply cost (deferral) accrual	(1,523)	1,523	—
Amortization to expense of prior year authorized balances	(14,503)	9,206	65,550
Total power cost adjustment expense	$ (61,090)	$ 38,497	$ 51,226

The power supply accruals or deferrals represent the portion of that period's power supply cost fluctuations accrued or deferred under the PCA mechanisms. Accruals represent additional costs being recorded as a result of actual power supply costs that were less than the amount forecasted in PCA rates. The power supply cost is a deferral in 2012 because actual power supply costs in 2012 were higher than the amounts forecasted in PCA rates. If actual power supply costs are greater than the amount forecasted in PCA rates, the majority of the excess is deferred. The amortization of the prior year's balances represents the amounts being collected (refunded) in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2012 Compared to 2011: Actual net power supply costs increased in 2012 relative to 2011, resulting in a change of $75.9 million—from accruals of $29.3 million to deferrals of $46.6 million. The $14.5 million of amortization reflects the net refunding to customers of prior years' accruals.

PCA Mechanisms - 2011 Compared to 2010: Actual net power supply costs decreased in 2011 relative to 2010, resulting in a change of $43.6 million—from a deferral of $14.3 million to an accrual of $29.3 million. For 2011, net collections on previously deferred amounts have decreased due to lower PCA true-up rates, reducing the PCA amortization by $56.3 million.

Other Operations and Maintenance Expenses: An explanation of the changes in operations and maintenance expenses for the periods presented is below.

O&M - 2012 Compared to 2011: A $10.4 million increase in other O&M expense in 2012 as compared to 2011 was principally due to:

- $9.0 million in higher administrative expenses related to various increases in consultant costs, software licenses and maintenance, insurance reserves, and other purchased services. A significant portion of the increase related to a lower reimbursement from the U.S. Department of Energy (DOE) for Smart Grid-related items in 2012 compared to 2011;
- increased payroll and other benefit expenses of $6.8 million related to normal increases in employee wages and costs of providing employee benefits; and
- a $3.2 million increase in transmission system maintenance expenses primarily related to line inspection costs; offset by
- a $9.1 million decrease in thermal plant O&M related to costs for maintenance outages that occurred in 2011 that did not recur in 2012, as well as lower overall maintenance costs and consumable supplies due to lower utilization of these plants during the first half of 2012. The lower utilization was predominantly driven by low wholesale energy prices in the region during that period.

O&M - 2011 Compared to 2010: The $44.7 million increase in other O&M expense in 2011 as compared to 2010 was principally due to:

- $20.3 million of increased pension expenses relating to the settlement stipulation that reduced a portion of Idaho customers' future obligation through a reduction in the pension regulatory asset;
- increased pension and other benefit expenses of $11.5 million, primarily due to pension expense amortization that began in June 2010 and was increased in June 2011 in conjunction with recovery of deferred pension costs in rates;
- $5.0 million in higher thermal O&M due to maintenance outages at the Valmy plant, partially offset by an equipment impairment taken in 2010 at the Bridger plant that did not recur in 2011; and
- an increase in other payroll related costs of $5.7 million; offset by
- a combination of lower meter reading expense and the completed amortization of certain DSM expenses of $3.5 million, and lower outside service fees of $2.3 million.

Income Taxes

Income Tax Expense: IDACORP's and Idaho Power's income tax expense for 2012 increased significantly relative to 2011, primarily as a result of greater pre-tax earnings in 2012 and the tax benefits from IRS examination settlements recorded in 2011. Income tax expense in 2011 decreased significantly compared to 2010, principally as a result of an IRS examination settlement in 2011 related to Idaho Power's uniform capitalization tax accounting method. For additional information relating to IDACORP's and Idaho Power's income taxes, see Note 2 - "Income Taxes" to the consolidated financial statements included in this report.

Bonus Depreciation: The Small Business Jobs Act (Jobs Act) and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) include provisions for the extension and increase of bonus depreciation. Bonus depreciation provides for the accelerated deduction of current capital expenditures from certain asset classes. The Jobs Act extended 50 percent bonus depreciation to 2010 and the Tax Relief Act extended bonus depreciation to 2011-2012 and increased it to 100 percent for a portion of 2010 and 2011. In addition, the American Taxpayer Relief Act of 2012 extended 50 percent bonus depreciation to 2013. Idaho Power has included an estimated bonus deprecation deduction in its current income tax provision. The estimated deduction would reduce Idaho Power's 2012 federal income tax liability by approximately $81 million. Idaho Power is evaluating the impacts the extension of bonus depreciation could have on its 2013 income taxes. The state of Idaho did not conform to the federal bonus depreciation rules for 2010-2013.

Net Operating Loss and Tax Credit Carryforwards: IDACORP finished 2012 with a federal net operating loss carryforward of $156 million, a federal general business tax credit carryforward of $107 million, and a $38 million Idaho investment tax credit carryforward. Based on the expiration dates of the credits, as described in Note 2 - "Income Taxes - Tax Credit Carryforwards and Net Operating Loss Carryforwards" to the consolidated financial statements included in this report, these amounts are expected to provide future cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Overview

IDACORP's and Idaho Power's operating cash flows are driven principally by Idaho Power's sales of electricity and transmission capacity. Significant uses of cash flows from operations include the purchase of fuel and power, other operating expenses, capital expenditures, pension plan contributions, and interest. Operating cash flows can be significantly influenced by factors such as weather conditions, rates and the outcome of regulatory proceedings, and economic conditions. As fuel and purchased power are significant uses of cash, and at the same time their prices can be volatile and difficult to predict, Idaho Power has regulatory mechanisms in place that provide for the deferral and recovery of the majority of the fluctuation in those costs. However, if actual costs rise above the level allowed in retail rates, deferral balances increase (reflected as a regulatory asset), negatively affecting operating cash flows until such time as those costs, with interest, are recovered from customers. Idaho Power uses operating and capital budgets to control operating costs and optimize capital expenditures, and funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. Idaho Power seeks to recover its operating costs and earn a return on its capital expenditures through rates, periodically filing for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators.

Idaho Power continues to make significant infrastructure investments. During 2012 Idaho Power added capacity to its baseload generation through the completion of construction of the Langley Gulch power plant. Idaho Power has also been pursuing significant transmission system enhancements and upgrading distribution facilities in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Additionally, Idaho Power's aging hydroelectric and thermal generation facilities require continuing upgrades and component replacement, and the costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Idaho Power estimates that total capital expenditures will be between $815 million and $835 million over the period from 2013 through 2015. A significant focus for 2013 will be to control costs and generate sufficient cash from operations to meet operating needs, contribute to capital expenditure requirements, and pay dividends to shareholders.

As of February 15, 2013, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $125 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement, which it may use for the issuance of debt securities and common stock, including up to 3.0 million shares of IDACORP common stock available for issuance under its continuous equity program. Approximately $539 million of debt and equity securities issuances remained available under the shelf registration statement;
- Idaho Power's shelf registration statement, which it may use for the issuance of first mortgage bonds and debt securities; $150 million remained available under the shelf registration statement, which expires in May 2013; and
- IDACORP's and Idaho Power's issuance of commercial paper, which may be issued up to an amount equal to the available credit capacity under their respective credit facilities, and is used to meet short-term liquidity requirements.

IDACORP and Idaho Power monitor capital markets with a view toward opportunistic debt and equity transactions where possible in light of future needs. To meet maturing long-term debt obligations and costs of infrastructure development, such as Idaho Power's 500-kV transmission projects, the companies may use a combination of internally generated funds, credit facilities, the issuance of long-term debt or equity and, in the case of Idaho Power, capital contributions from IDACORP. IDACORP and Idaho Power expect to continue financing capital requirements during 2013 with a combination of internally generated funds and externally financed capital, and believe that access to their credit facilities and commercial paper, operating cash flows generated by Idaho Power's utility business, and ability to issue medium-term notes will be sufficient to meet short-term obligations and debt maturities in 2013. Idaho Power has $70 million of first mortgage bonds due in October 2013, with no first mortgage bonds due thereafter until 2018. IDACORP and Idaho Power expect a minimal need for any additional external financing in 2013, other than for the repayment of the first mortgage bonds due in October 2013 and issuances of commercial paper to meet cash balancing needs from time-to-time.

Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases of IDACORP common stock for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. However, IDACORP may determine at any time to resume original issuances of common stock under those plans. IDACORP may also determine to issue common stock from time-to-time under its continuous equity program, depending on market conditions and capital needs. An important component of that determination will be IDACORP's and Idaho Power's capital structure. IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2012, IDACORP's and Idaho Power's capital structures were as follows:

	IDACORP	Idaho Power
Debt	48%	49%
Equity	52%	51%

Operating Cash Flows

IDACORP's and Idaho Power's operating cash inflows for the year ended December 31, 2012 were $249 million and $258 million, respectively. IDACORP's operating cash flows decreased by $61 million and Idaho Power's decreased by $35 million compared to the year ended December 31, 2011. With the exception of cash flows related to income taxes, IDACORP's operating cash flows are principally derived from the operating cash flows of Idaho Power. Significant items that affected the companies' operating cash flows in 2012 relative to 2011 included:

- Idaho Power made contributions of $44.3 million to its defined benefit pension plan in 2012, compared with a $18.5 million cash contribution in 2011;

- cash outflows related to income taxes increased by $14 million for IDACORP, while cash inflows related to income taxes increased by $14 million for Idaho Power. IDACORP paid income taxes of $1 million in 2012 compared with receiving $12 million of income tax refunds in 2011. Idaho Power's net refunds from IDACORP for income tax were $15 million for 2012, compared with $1 million for 2011;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $100 million, as Idaho Power collected $24 million less of previously deferred costs due to decreases in PCA rates and incurred $76 million less in the current year PCA accrual, as compared with 2011; and
- Idaho Power's joint venture, BCC, made net distributions to Idaho Power of $18 million for 2012, as compared to a $3 million net contribution for 2011. The change from year to year is the result of BCC having more cash to distribute in 2012 than 2011. There were less capital investments in 2012 than 2011, less operating cash invested in coal inventory in 2012 than 2011, and higher reclamation activities in 2012 than 2011 causing an increase in the amount of disbursements from the reclamation trust to BCC.

IDACORP's and Idaho Power's operating cash inflows for the year ended December 31, 2011 were $310 million and $292 million, respectively. IDACORP's operating cash flows increased by $5 million and Idaho Power's decreased by $38 million compared to the year ended December 31, 2010. Significant items that affected operating cash flows in 2011 included:

- income before income taxes decreased by $27 million for IDACORP and $28 million for Idaho Power;
- in 2011, Idaho Power recorded a $27 million regulatory liability in addition to a $20 million reduction to pension-related regulatory assets as a result of sharing mechanisms, which reduced income before income taxes but did not reduce operating cash flows. No sharing was recorded during 2010;
- cash outflows related to the pension and postretirement benefit plans decreased by $44 million. Idaho Power made an $18.5 million cash contribution to its defined benefit pension plan in 2011, compared with a $60 million cash contribution in 2010;
- cash inflows related to income taxes decreased by $15 million and $57 million for IDACORP and Idaho Power, respectively. IDACORP received income tax refunds of $12 million in 2011 compared with $27 million in 2010. Idaho Power's net refunds from IDACORP for income tax were $1 million for 2011, compared with $57 million for the same period in 2010;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $13 million, as Idaho Power collected $56 million less of previously deferred costs due to decreases in PCA rates, partially offset by a $44 million increase in the 2011 PCA accrual, as compared with 2010;
- changes in fuel inventories reduced operating cash flows by $18 million, as fuel on hand increased by $20 million during 2011 due to decreased thermal plant operation, compared with $2 million during the same period in 2010; and
- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances decreased cash flows by $10 million, as Idaho Power collected more during 2010 than it recorded as revenues while collecting less during 2011 than it recorded as revenues.

Investing Cash Flows

Investing activities are predominantly related to capital expenditures for new construction and improvements to Idaho Power's generation, transmission, and distribution facilities. These capital expenditures address peak demand growth, aging plant and equipment, and customer growth. Idaho Power's construction expenditures were $240 million, $338 million, and $338 million in 2012, 2011, and 2010, respectively. Construction expenditures during the periods were heavily impacted by construction costs for the Langley Gulch power plant. In 2010, construction expenditures were partially offset by proceeds from the sale of $19 million of transmission-related assets to PacifiCorp. IDACORP cash flows relating to investments in affordable housing through IFS were $0.1 million, $2 million, and $13 million in 2012, 2011, and 2010, respectively.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, energy and price hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, credit facilities, and contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho

Power, and non-utility expenses allocated to IDACORP, through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities.

Debt: On June 17, 2010, Idaho Power entered into a Selling Agency Agreement with Banc of America Securities LLC; BNY Mellon Capital Markets, LLC; J.P. Morgan Securities Inc.; KeyBanc Capital Markets Inc.; Merrill Lynch, Pierce, Fenner & Smith Incorporated; Mitsubishi UFJ Securities (USA), Inc.; RBC Capital Markets Corporation; SunTrust Robinson Humphrey, Inc.; U.S. Bancorp Investments, Inc.; and Wells Fargo Securities, LLC in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds under a shelf registration statement.

On August 30, 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, Series I due 2020 and $100 million of 4.85% first mortgage bonds, Series I due 2040 under a shelf registration statement. On March 2, 2011, Idaho Power repaid at maturity $120 million of its 6.60% first mortgage bonds (secured notes) using a portion of the proceeds from the first mortgage bonds issued in August 2010. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022 and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042, under the Selling Agency Agreement and shelf registration statement. In April 2012, Idaho Power issued an irrevocable notice of redemption to redeem, prior to maturity, its $100 million in principal amount of 4.75% first mortgage bonds, medium-term notes due November 2012. In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 issuance of first mortgage bonds, medium-term notes to effect the redemption. Idaho Power's next upcoming material long-term debt principal repayment obligation is its $70 million of 4.25% first mortgage bonds that mature in October 2013.

Equity: IDACORP has entered into sales agency agreements as a means of selling its common stock from time to time in at-the-market offerings. IDACORP did not issue any shares under these agreements in 2012 or 2011. In 2010, IDACORP received $34 million, net of agent's fees, from the issuance of 973,585 shares of IDACORP common stock at an average price of $35.47. IDACORP entered into a new sales agency agreement with BNY Mellon Capital Markets, LLC on December 16, 2011, replacing a December 2008 sales agency agreement that provided for the sale of up to 3 million shares of IDACORP common stock. At the time of expiration of the December 2008 sales agency agreement in December 2011, 1,165,233 shares were unissued. As of February 15, 2013, 3 million shares remained available for issuance under the current sales agency agreement.

During the first half of 2012, IDACORP continued to issue common stock under the pre-existing dividend reinvestment and employee-related stock purchase plans. Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. Under these plans, IDACORP issued 111,380 shares in 2012, 211,276 shares in 2011, and 250,030 shares in 2010, for proceeds of $4.5 million, $8.2 million, and $8.6 million, respectively.

IDACORP issued 8,600 shares of IDACORP common stock in 2012, 255,746 shares in 2011, and 194,860 shares in 2010, in connection with the exercise of stock options, for proceeds of $0.4 million, $9.4 million, and $5.4 million, respectively.

IDACORP and Idaho Power paid dividends of $69 million, $60 million, and $58 million in 2012, 2011, and 2010, respectively. IDACORP made capital contributions of $8 million, $16 million, and $50 million to Idaho Power in 2012, 2011, and 2010, respectively.

Financing Programs

Shelf Registrations: IDACORP has an effective shelf registration statement that, as of the date of this report, can be used for the issuance of up to $539 million of debt securities and common stock. Idaho Power has an effective registration statement that, as of the date of this report, can be used for the issuance of up to $150 million of first mortgage bonds and unsecured debt.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture of Mortgage and Deed of Trust, market conditions, regulatory authorizations, and covenants contained in other financing agreements. The Indenture of Mortgage and Deed of Trust limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture of Mortgage and Deed of Trust. As of December 31, 2012, Idaho Power could issue approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. However, the Indenture of Mortgage and

Deed of Trust further limits the maximum amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2012 was limited to approximately $489 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust.

Refer to Note 4 - "Long-Term Debt" to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

Credit Facilities: IDACORP and Idaho Power have $125 million and $300 million credit facilities, respectively. Each of the credit facilities may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $125 million at any one time outstanding, including swingline loans not to exceed $15 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 0.65 as of the end of each fiscal quarter. In determining the leverage ratio, "consolidated indebtedness" broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). "Consolidated total capitalization" is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities, which could limit the ability of the companies to issue first mortgage bonds and debt securities. There are additional 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 from any material subsidiary. At February 15, 2013, IDACORP and Idaho Power were in compliance with all facility covenants. Further, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2013, but were circumstances to arise that may alter that view management would take appropriate action to mitigate any such issue.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

While the credit facilities provide for an original maturity date of October 26, 2016, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On October 12, 2012, IDACORP and Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity date under both agreements to October 26, 2017. No other terms of the credit agreements, including the amount of permitted borrowings under the credit agreements, were affected by the extension.

Without additional approval from the IPUC, the OPUC, and the Public Service Commission of Wyoming, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

Commercial Paper: IDACORP and Idaho Power have commercial paper programs under which they may issue unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time not to exceed the available capacity under their respective credit facilities, described above. IDACORP's and Idaho Power's credit facilities are available to the companies to support borrowings under their commercial paper programs. The commercial paper issuances are used to provide an additional financing source for the companies' short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Individual instruments carry a fixed rate during their respective terms, although the interest rates are reflective of current market conditions, subjecting the companies to fluctuations in interest rates.

Available Short-Term Liquidity: The following table outlines available short-term borrowing liquidity as of the dates specified.

	December 31, 2012		December 31, 2011	
	IDACORP[2]	Idaho Power	IDACORP[2]	Idaho Power
Revolving credit facility	$ 125,000	$ 300,000	$ 125,000	$ 300,000
Commercial paper outstanding	(69,700)	—	(54,200)	—
Identified for other use[1]	—	(24,245)	—	(24,245)
Net balance available	$ 55,300	$ 275,755	$ 70,800	$ 275,755

[1] Port of Morrow and American Falls bonds that Idaho Power could be required to purchase prior to maturity under the optional or mandatory purchase provisions of the bonds, if the remarketing agent for the bonds were unable to sell the bonds to third parties.

[2] Holding company only.

At February 15, 2013, IDACORP had no loans outstanding under its credit facility and $64.0 million of commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding. The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2012 and 2011:

	December 31, 2012		December 31, 2011	
	IDACORP [1]	Idaho Power	IDACORP[1]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$ 69,700	$ —	$ 54,200	$ —
Weighted average interest rate	0.50%	—%	0.47%	—%
Daily average amount outstanding during the year	$ 57,947	$ 3,578	$ 65,574	$ —
Weighted average interest rate during the year	0.48%	0.47%	0.41%	—%
Maximum month-end balance	$ 69,800	$ 12,000	$ 74,400	$ —

[1] Holding company only.

Impact of Credit Ratings on Liquidity and Collateral Obligations

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, depends in part on their respective credit ratings. The following table outlines the ratings of Idaho Power's and IDACORP's securities, and the ratings outlook, by Standard & Poor's Ratings Services and Moody's Investors Service as of the date of this report:

	S&P		Moody's	
	IDACORP	Idaho Power	IDACORP	Idaho Power
Corporate Credit Rating/Long-Term Issuer Rating	BBB	BBB	Baa 2	Baa 1
Senior Secured Debt	None	A-	None	A2
Senior Unsecured Debt	None	BBB	None	Baa 1
Short-Term Tax-Exempt Debt	None	BBB/A-2	None	Baa 1/ VMIG-2
Commercial Paper	A-2	A-2	P-2	P-2
Senior Unsecured Credit Facility	None	None	Baa 2	Baa 1
Rating Outlook	Stable	Stable	Stable	Stable

These security ratings reflect the views of the ratings agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2012, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on its unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral, and counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2012, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $7.2 million. To minimize capital requirements, Idaho Power actively monitors its portfolio exposure and the potential exposure to additional requests for performance assurance collateral, through sensitivity analysis.

Capital Requirements

Idaho Power's construction expenditures, excluding AFUDC, were $228 million during the year ended December 31, 2012, including $28 million for construction of the Langley Gulch power plant. The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2013 through 2015 (in millions of dollars).

	2013	2014-2015
Ongoing capital expenditures (excluding item listed below in this table)	$210-218	$500-505
Jim Bridger plant SCR (detailed below)	35-37	70-75
Total	$245-255	$570-580

Major Infrastructure Projects: Idaho Power has recently completed and is undertaking a number of significant infrastructure projects, described below.

<u>Langley Gulch Power Plant</u>: The Langley Gulch power plant is a natural gas-fired combined-cycle combustion turbine power generating plant with a generation nameplate capacity of 318 MW. Idaho Power placed the plant in service on June 29, 2012. Idaho Power incurred approximately $397 million ($352 million, excluding AFUDC) of capital expenditures associated with the project from inception to December 31, 2012.

<u>AMI/Smart Grid and American Recovery and Reinvestment Act of 2009 (ARRA)</u>: The advanced metering infrastructure project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In December 2011, Idaho Power completed the installation of its advanced metering technology at a cost of $71.8 million. Under the ARRA, Idaho Power was awarded a grant of $47 million from the DOE for the advanced metering technology and a new customer information and billing system. The grant was signed by the DOE in April 2010 and applies to project costs incurred beginning in August 2009 for a three-year term. As of December 31, 2012, Idaho Power had invoiced approximately $41.5 million to the DOE, of which $41 million had been received. The costs to be reimbursed by the grant are not included in the Capital Requirements table above.

Jim Bridger Plant Selective Catalytic Reduction: Idaho Power and the plant co-owners intend to install selective catalytic reduction (SCR) equipment to reduce nitrogen oxide (NO_x) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. SCR is required to be installed and operational on unit 3 by 2015 and unit 4 by 2016. An equivalent technology will be required for NO_x reductions on unit 2 by 2021 and unit 1 by 2022. Idaho Power estimates that the total cost for Idaho Power's share of the upgrades on units 3 and 4 is approximately $120 million, excluding AFUDC. While Idaho Power does not have estimates for the cost to install SCR on units 1 and 2, particularly given the technological changes that may occur prior to the installation date on those units, it is possible that the costs will be equal to, or greater than, the costs for units 3 and 4. Refer to Part I, Item I - "Business - Environmental Regulation and Costs" and Part II, Item 7 - "MD&A - Environmental Matters" for additional discussion on environmental controls and anticipated costs, which will be significant in the foreseeable future.

Boardman-to-Hemingway Transmission Line: The Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, would provide transmission service to meet needs identified in the 2011 IRP. Idaho Power's estimated share of the cost of the permitting phase of the project is $13 million, including AFUDC. Total cost estimates for the project are between approximately $890 million and $940 million, including AFUDC. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the permitting phase are not included in the table above.

In January 2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into a Joint Permit Funding Agreement (B2H Funding Agreement), which provides that the parties will seek to jointly fund and support the process of completing environmental studies, including an environmental impact statement (EIS) pursuant to the National Environmental Policy Act, and obtaining governmental authorizations and permits for rights-of-way over public lands, necessary to develop the project. The planning, design, procurement, and acquisition of private rights-of-way, private easements, and similar private property interests are not within the scope of the B2H Funding Agreement. Idaho Power is designated as the project manager, responsible for administering and overseeing the project and for the day-to-day activities involved in advancing the project. The B2H Funding Agreement assigns each party a permitting interest based on each party's specified capacity ownership interests. The agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 for PacifiCorp in the project. The agreement further provides that during future negotiations pertaining to development and construction agreements, the parties will seek to retain interests in the project equal to their respective permitting interests. PacifiCorp or BPA may withdraw from the B2H Funding Agreement at any time.

In October 2012, the BPA issued a statement that it had completed an initial prioritization of potential service arrangements for its customer load in southeastern Idaho and, while it had not made a final decision on options for this service, the BPA identified the Boardman-to-Hemingway line with a transmission asset swap as a top priority for pursuit during 2013 and beyond. According to the BPA, of the options it evaluated, the Boardman-to-Hemingway line with a transmission asset swap has the potential to keep the BPA's costs low relative to the other options considered.

Federal and state permitting continues to move forward with a draft EIS expected to be issued in mid-2013. The completion date of the project is subject to siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions. Based on Idaho Power's assessment of those and other factors, Idaho Power continues to believe that a project in-service date prior to 2018 is unlikely.

Memorandum of Understanding, dated January 12, 2012, among Idaho Power, PacifiCorp, and BPA (2012 MOU): Executed in connection with the BPA's participation in the joint funding agreement for the Boardman-to-Hemingway line, the 2012 MOU provides that the parties will negotiate in good faith the terms of mutually satisfactory definitive agreements that would allow BPA to meet its load service obligations in southeast Idaho. It provides that the parties will explore opportunities to establish eastern Idaho load service from the Hemingway substation in exchange for similar service from the Federal Columbia River Transmission System. The 2012 MOU outlines at least two potential alternatives for further negotiation, including a network service option and an asset ownership rights option on the parties' transmission systems, both of which include BPA participation in the Boardman-to-Hemingway transmission line. Any party may terminate the 2012 MOU at any time, without penalty, and the 2012 MOU automatically expires on December 31, 2014.

Gateway West Transmission Line: Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $24 million, including AFUDC. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $150 million and $300 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs are not included in the table above. Timing of the construction of each segment of the project is subject to siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions.

In January 2012, Idaho Power and PacifiCorp entered into a Project Development Agreement (Gateway Funding Agreement) outlining the terms under which the parties will jointly own, develop, design, permit, site, 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, comprised of 88, 126, 152, and 34 miles, respectively and each of which is 500-kV. PacifiCorp is designated as the project manager under the agreement. The Gateway Funding Agreement provides that the project manager may seek to reconfigure portions of the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations. Further, PacifiCorp retains the right to remove specified segments from the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations specified in the Gateway Funding Agreement.

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 percent for each of segments 8, 9, and 10, with a federal permitting interest in the project of 11 percent. The Gateway Funding Agreement provides for the parties to subsequently meet to negotiate the terms and conditions of one or more definitive development and construction agreements for the Gateway West transmission line. The agreement specifies that the parties intend that the terms of any construction agreement would provide that Idaho Power is entitled to one-third of the anticipated bi-directional transmission capacity on segments 8, 9, and 10, and one-third of any total incremental system capacity on those segments, and that PacifiCorp is entitled to the remaining two-thirds interest. A party may withdraw from the federal permitting project, all or a portion of the state permitting project (relating to one or two of segments 8, 9, and 10), or the agreement in its entirety. Upon withdrawal, the withdrawing party forfeits its rights, title, and interest in the agreement and associated tangible and intangible property rights or, if withdrawing from less than all segments, its rights, title, and interest in those segments from which it withdraws.

In October 2012, the U.S. Bureau of Land Management (BLM) released its preferred routes for the project, and Idaho Power is engaged in discussions with stakeholders as the routes are evaluated. While the BLM's schedule provides for the issuance of a final EIS in the first quarter of 2013 and a record of decision in mid-2013, Idaho Power expects that those milestones could be delayed until later in 2013.

<u>Shoshone Falls Plant Expansion:</u> The Shoshone Falls plant expansion project was included in Idaho Power's 2011 IRP and consists of constructing a new powerhouse, intake structure, penstock, and substation and the installation of a new turbine to increase the nameplate generation capacity of the plant from 12.5 MW to 61.5 MW. Idaho Power estimates the total cost of the generation capacity expansion project to be $116 million, excluding AFUDC, with an in-service date during 2019, subject to the outcomes of further engineering and cost studies and regulatory authorization. The estimated 2019 in-service date is a two year delay from the prior estimated 2017 in-service date.

2013 IRP Update and Potential Changes to Capital Project Mix: As a public utility under the jurisdiction of the FERC, the IPUC, and the OPUC, Idaho Power is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, to construct and place in service sufficient generation and transmission capacity to reliably deliver resources to network customers and the company's retail customers, and otherwise take actions to fulfill its obligation to provide safe and reliable electric service. As part of its resource planning, and in accordance with regulatory requirements, Idaho Power prepares and publishes an IRP every two years. The IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and near-term and long-term action plans. Idaho Power's future resource build-out plans are heavily influenced by the results of the IRP process. Refer to Item 1 - "Business - Utility Operations - Resource Planning" in this report for additional information on Idaho Power's IRP.

Based on preliminary work conducted on the 2013 IRP, Idaho Power expects a significant change in its assumptions relative to the 2011 IRP. In the 2011 IRP, Idaho Power identified resource needs in the relative near-term. However, based on one scenario that would exclude demand response programs and power capacity from the proposed Boardman-to-Hemingway 500-kV transmission line, the preliminary peak-hour load and resource balance prepared for the 2013 IRP indicates no peak-hour load deficit until 2016. Under those assumptions, the need for near-term peak-hour resources does not exist. Idaho Power anticipates that the expected near-term resource sufficiency will impact the timing of development of supply-side resources, including those described above, and the need for demand response programs in the near-term.

At times, Idaho Power may seek to accelerate, scale back, modify, or eliminate projects, or seek alternative projects, to accommodate anticipated resource needs and to help ensure its ability to provide reliable electric service and meet load and transmission capacity obligations. Scaling back or eliminating a project due to regulatory challenges or other factors influencing the feasibility of a project may result in Idaho Power pursuing one or more separate, more costly projects. For instance, if Idaho Power were unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, develop additional generation facilities within areas where Idaho Power has available transmission capacity. Idaho Power's IRP seeks to address these potential alternatives and their associated risks and costs. Termination of a project carries with it the potential for a write-off of all or a significant portion of the costs associated with the project.

Environmental Regulation Costs: Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal plants and for its hydroelectric relicensing efforts. These cost estimates are summarized in Item 1 - "Business" of this report. The capital portion of these amounts is included in the Capital Requirements table above but do not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

Other Capital Requirements: IDACORP's non-regulated capital expenditures are primarily related to IFS's tax-structured investments. As of the date of this report, IDACORP does not anticipate any significant non-regulated expenditures for the period from 2013 through 2015.

Defined Benefit Pension Plan Contributions

Idaho Power contributed $44.3 million, $18.5 million, and $60 million to its defined benefit pension plan in 2012, 2011, and 2010, respectively. Idaho Power has evaluated the potential impact of recently approved federal legislation that will alter the timing and amount of future contributions to the defined benefit pension plan. The legislation, signed into law in July 2012, provides a smoothing mechanism applicable to the calculation of plan minimum contributions, and will reduce minimum amounts required to be contributed to the plan in at least the next few years. The legislation's partial funding relief is automatically effective for all contributions beginning in 2013, and Idaho Power chose to adopt the funding relief for its 2012 contributions. Idaho Power does not have a minimum contribution requirement for 2013. In 2014 and beyond, Idaho Power expects significant contribution obligations under the pension plan. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations. In May 2011, the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. The primary impact of pension contributions is on cash flows, as cost recovery lags the timing of contributions.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations for the respective periods in which they are due:

	Payment Due by Period				
	Total	2013	2014-2015	2016-2017	Thereafter
	(millions of dollars)				
Idaho Power:					
Long-term debt[1]	$ 1,540	$ 71	$ 2	$ 2	$ 1,465
Future interest payments[2]	1,304	79	152	152	921
Operating leases	24	2	4	2	16
Purchase obligations:					
Cogeneration and small power production	3,858	171	369	379	2,939
Fuel supply agreements	308	74	120	19	95
Purchased power & transmission[3]	27	6	9	7	5
Other[4]	169	49	37	24	59
Pension and postretirement benefit plans[5]	277	7	91	136	43
Other long-term liabilities - Idaho Power	1	—	—	1	—
Total Idaho Power	7,508	459	784	722	5,543
Other	1	1	—	—	—
Total IDACORP	$ 7,509	$ 460	$ 784	$ 722	$ 5,543

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.

(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2012.

(3) Approximately $9 million of the obligations included in purchased power and transmission have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information estimated based on current contract terms has been included in the table for presentation purposes.

(4) Approximately $114 million of the amounts in other purchase obligations are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(5) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2017 with any level of precision, and amounts through 2017 are estimates only. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP's common stock are within the discretion of IDACORP's board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power.

IDACORP has a dividend policy that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the IDACORP board of directors' dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the foregoing factors, among others.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend, commencing with the dividend paid on February 29, 2012, to $0.33 per share of IDACORP common stock, from the prior quarterly dividend amount of $0.30 per share of IDACORP common stock. On September 20, 2012, IDACORP's board of directors voted to increase the quarterly dividend again in 2012, commencing with the dividend payable on November 30, 2012, to $0.38 per share of IDACORP common stock. As of the date of this report, IDACORP's management anticipates recommending to the board of directors an additional increase to the quarterly dividend in September 2013 of at least ten percent.

For additional information relating to IDACORP and Idaho Power dividends, including additional restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 – "Common Stock" to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future results of operations and financial condition. Certain legal or administrative proceedings to which IDACORP or Idaho Power are parties or are otherwise involved, and certain actual or potential legal claims pertaining to Idaho Power, are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, in many instances IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of potential new regulations, but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

Off-Balance Sheet Arrangements

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. 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.

Impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) establishes regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) and the SEC for certain swaps (which include a variety of derivative instruments) and the users of such swaps. While Idaho Power believes that a number of obligations arising from rules issued under the Dodd-Frank Act will not directly apply to Idaho Power, the company believes that other participants in the commodities markets (such as swap dealers and major swap participants) will pass along their increased costs. While implementation of the rules is in its infancy, and temporary operational disruptions and liquidity in the commodities markets could be adversely impacted, as of the date of this report Idaho Power expects that the long-term financial and operational impact of the swap-related provisions of the Dodd-Frank Act and the CFTC's and SEC's associated rules will not be significant.

REGULATORY MATTERS

Introduction

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the IPUC and the OPUC, which determine the rates that Idaho Power charges to its general business customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its OATT. Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, seeking to earn a return on investment where permitted by regulators. Idaho Power remains focused on communicating with regulators the necessity of investments to better serve its customers, the prudence of the costs incurred, and the importance of a reasonable return on investment for IDACORP's shareholders.

Idaho Power's need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, among other things, in-service dates of major capital investments and the timing of changes in major revenue and expense items. Idaho Power filed general rate cases in Idaho and Oregon during 2011, as well as a single-issue rate case for the Langley Gulch power plant in Idaho and Oregon in 2012, which have largely concluded. Idaho Power will continue to assess its need for general rate relief in consideration of the factors described above. Between general rate cases, Idaho Power relies upon power cost adjustment mechanisms, riders, and other mechanisms to reduce regulatory lag, which refers to the period of time between making an investment or incurring an expense and earning a return and recovering that investment or expense. Management's focus on constructive regulatory outcomes in 2011 and 2012 has been targeted largely at general revenue rate cases and rate mechanisms. For 2013, management will have a renewed focus on optimizing operations, evaluating and managing employee attrition, and managing growth in expenses.

Regulatory mechanisms and other regulatory matters, including in many cases their design and their financial impact on IDACORP and Idaho Power, are also discussed in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, which should be read in conjunction with the discussion below.

Idaho and Oregon Significant Regulatory Developments

Included below are notable regulatory developments affecting Idaho Power and largely completed during 2010, 2011, and 2012. Refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for a description of the applicable regulatory mechanism and associated orders of the IPUC and OPUC.

Description	Effective Date	Estimated Annualized $ Impact (millions)[1]
2010 Idaho settlement	6/1/2010	$ 89
2010 Idaho PCA [2]	6/1/2010	(147)
2010 Idaho pension expense recovery	6/1/2010	5
2010 Oregon annual power cost update [2]	6/1/2010	3
2011 Idaho PCA [2]	6/1/2011	(40)
2011 Idaho pension expense recovery	6/1/2011	12
2011 Oregon annual power cost update [2]	6/1/2011	(2)
2011 Idaho general rate case settlement	1/1/2012	34
2012 Oregon general rate case settlement	3/1/2012	2
2012 Idaho PCA[2]	6/1/2012	43
Idaho - Boardman power plant cost recovery	6/1/2012	1
Revenue sharing pursuant to January 2010 Idaho settlement agreement [2]	6/1/2012	(27)
Idaho depreciation rate for non-AMI meters	6/1/2012	(11)
Idaho depreciation update (other than non-AMI meters and Boardman plant)	6/1/2012	(1)
2012 Oregon annual power cost update [2]	6/1/2012	2
Idaho - Langley Gulch power plant	7/1/2012	58
Oregon - Langley Gulch power plant	10/1/2012	3

(1) The annual amount collected in rates is typically not recovered on a linear basis (i.e., 1/12th per month), and is instead recovered based on seasonality of sales and through Idaho Power's tiered rate structure, described above in this MD&A. Under a tiered rate structure, Idaho Power generally records revenues disproportionately during higher-load periods.

(2) The rate changes for the Idaho PCA and $27.1 million rate decrease resulting from revenue sharing pursuant to the January 2010 settlement agreement are applicable only for one-year periods. Similarly, a portion of the rate changes from the Oregon annual power cost update are applicable only for one-year periods.

Resetting of Idaho Base Rates -- 2011 Idaho General Rate Case Settlement: In December 2011, the IPUC approved a settlement stipulation in Idaho Power's Idaho general rate case, which provided for a 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdictional base rate revenues. New rates in conformity with the settlement became effective on January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

Resetting of Oregon Base Rates - 2012 Oregon General Rate Case Settlement: On February 23, 2012, the OPUC approved a settlement stipulation in Idaho Power's Oregon general rate case providing for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation went into effect on March 1, 2012. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger coal-fired power plant.

Idaho ROE Support Through 2014 via December 2011 Settlement: In December 2011, the IPUC issued an order, separate from the then-pending Idaho general rate case proceeding, approving a settlement stipulation that provided as follows:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdictional earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA adjustment; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho-jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 25 percent to Idaho Power and 75 percent to benefit Idaho customer rates through an offset in the pension balancing account, which would reduce the amount Idaho Power would collect from customers in future rates.

The December 2011 settlement stipulation provided that the Idaho ROE 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. As Idaho Power's 2012 Idaho ROE exceeded 10.5 percent, Idaho Power did not amortize additional ADITC in 2012. In accordance with the sharing provisions of the settlement stipulation, Idaho Power recorded a $7.2 million provision against current revenues, to be refunded to customers through a future rate reduction, and an additional $14.6 million of pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future.

The December 2011 settlement and sharing mechanism followed a similar Idaho settlement and sharing mechanism approved in January 2010, described further in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, which had a substantial impact on IDACORP's and Idaho Power's 2011 results of operations (as discussed in Note 3).

Increase in Rate Base -- Completion and Inclusion of the Langley Gulch Power Plant: The Langley Gulch power plant became commercially available on June 29, 2012. On that date the IPUC issued an order approving a $58.1 million, or 6.83 percent, increase in annual Idaho-jurisdiction base rates, effective July 1, 2012, for recovery of Idaho Power's investment in the power plant and associated costs. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon-jurisdiction base rates for recovery of the investment and associated costs, with new rates in effect October 1, 2012.

Change in Deferred (Accrued) Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual forecasts of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. The table that follows summarizes the change in deferred net power supply costs over the last two years.

		Idaho		Oregon[1]		Total
Balance at December 31, 2010	$	17,559	$	12,194	$	29,753
Current period net power supply costs accrued		(27,768)		(1,523)		(29,291)
Prior costs expensed and recovered through rates		(6,849)		(2,357)		(9,206)
Transfer of energy efficiency expenditures		10,000		—		10,000
SO_2 allowance and renewable energy certificate (REC) sales		(5,884)		(447)		(6,331)
Interest and other		(179)		623		444
Balance at December 31, 2011		(13,121)		8,490		(4,631)
Current period net power supply costs deferred		45,063		1,523		46,586
2011 revenue sharing liability applied to PCA true-up mechanism[2]		(27,201)		—		(27,201)
Prior deferred costs amortized and refunded (recovered) through rates		33,332		(2,178)		31,154
SO_2 allowance and renewable energy certificate (REC) sales		(3,217)		(160)		(3,377)
Interest and other		(285)		656		371
Balance at December 31, 2012	$	34,571	$	8,331	$	42,902

(1) Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $3 million). Deferrals are amortized sequentially.

(2) 2011 revenue sharing includes a $27.1 million liability together with carrying charges.

FERC Compliance Programs

The FERC has approved an extensive number of reliability standards developed by the NERC and the Western Electricity Coordinating Council (WECC), including critical infrastructure protection (CIP) standards and regional standard variations. As part of its compliance program, Idaho Power periodically reviews its operations for compliance with FERC rules, orders, and standards and self-reports compliance issues to the FERC and the WECC. Recent reports Idaho Power has submitted to the FERC have generally focused on Standards of Conduct and Idaho Power's FERC OATT. Consistent with prior years, during 2012 Idaho Power self-reported to the FERC and received notices of alleged violations from the FERC and the WECC. Idaho Power has also received notification that the FERC intends to take no further action regarding several issues previously reported by Idaho Power. Consistent with its historical practice, Idaho Power is working with the FERC and the WECC to resolve alleged violations and items it self-reported to the FERC and the WECC. Idaho Power is unable to predict what action, if any, the WECC or the FERC will take on those unresolved matters, but based on the nature of the potential violations Idaho Power does not expect any material adverse effect from currently alleged violations on its financial position, results of operations, or cash flows. Idaho Power plans to continue its efforts to reduce potential violations through its compliance program and its approach of self-reporting compliance issues to, and working with, the FERC and the WECC.

Relicensing of Hydroelectric Projects

Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses have a term of 30 to 50 years depending on the size, complexity, and cost of the project. Costs for the relicensing of Idaho Power's hydroelectric projects are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $161 million for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2012. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.6 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. Through December 31, 2012, Idaho Power has collected approximately $24.7 million ($41.6 million grossed up for income taxes) of AFUDC related to the HCC relicensing project through customer rates. In addition to the discussion below, see "Environmental Matters" in this MD&A for a discussion of environmental compliance under FERC licenses for Idaho Power's hydroelectric generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application with the FERC for a new license in anticipation of the July 2005 expiration of the then-existing license. Since the expiration of that license, Idaho Power has been operating the project under annual licenses issued by the FERC. In December 2004, Idaho Power and eleven other parties, including NMFS and

USFWS, involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. In August 2007 the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act (CWA) and formal consultations under the Endangered Species Act (ESA), which remain unresolved.

In connection with its relicensing efforts, Idaho Power has filed water quality certification applications, required under Section 401 of the CWA, with the states of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Section 401 of the CWA requires that a state either approve or deny a Section 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its Section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

In September 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species, including the bull trout and fall Chinook salmon and steelhead, under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed. Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns. Measures that have been contemplated include potential watershed improvements or the installation of a temperature control structure to address water temperatures during a small portion of the year. Both the watershed approach and temperature control structure would add substantially to project costs. For instance, in its August 2007 final EIS the FERC's proposed protection, mitigation, and enhancement measures had an estimated cost of approximately $15 million per year, excluding costs associated with the Section 401 certification because they had not been defined at that time, and remain undefined. As of the date of this report, Idaho Power is unable to predict the timing of issuance by the FERC of any license order or the ultimate capital investment and ongoing operating and maintenance costs Idaho Power will incur in complying with the license.

Swan Falls Project: In September 2012, the FERC issued to Idaho Power a 30-year license for continued operation of the Swan Falls hydroelectric project (SFP). Idaho Power believes that operational changes associated with the new license for the SFP will be modest and that the capital investments it will be required to make under the terms of the license will be within the range Idaho Power expected at the time of submission of its application for the license.

Shoshone Falls Plant Expansion: On July 1, 2010, the FERC amended the license for the Shoshone Falls project to expand its nameplate generating capacity from approximately 12.5 MW to approximately 61.5 MW. The amended license has an expiration date of 2034, but provides that the license will be extended to 2044 following completion of the proposed generation capacity expansion project. On May 1, 2012, FERC granted Idaho Power a two-year schedule extension, through July 2017, to complete construction of the expansion. However, Idaho Power does not expect that it would complete the generation capacity expansion project prior to 2019, and thus plans to request an additional two-year extension from the FERC. Idaho Power's determination to proceed with the expansion project remains subject to the outcome of additional cost studies and analysis and the results of further engineering and design work, and further analysis of Idaho Power's supply-side resource needs. If Idaho Power ultimately determines to move forward with the full project, Idaho Power plans to obtain regulatory support from the IPUC and OPUC prior to commencement of construction to mitigate in part the regulatory cost-recovery risk associated with the project.

Renewable Energy Contracts, Renewable Energy Certificates, and Emission Allowances

Renewable Portfolio Standards: Numerous proponents have introduced legislation in the U.S. Congress that would require electric utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal or State of Idaho RPS is in effect.

Idaho Power will be required to comply with a 10-percent RPS in Oregon beginning in 2025, and Idaho Power expects to meet this requirement with RECs from the Elkhorn Valley wind project. Idaho Power continues to monitor proposed federal RPS legislation and the possibility of additional state RPS legislation.

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2012 and 2011, Idaho Power's REC sales totaled $3.5 million and $6.5 million, respectively. Idaho Power has sold all of its 2011 and earlier vintage RECs. Idaho Power has sold a portion of its 2012 RECs and intends to continue selling its 2012 and later RECs as they are generated and become available for sale.

Were Idaho Power to be subject to additional RPS legislation, it may cease in full or in part the sale of RECs it receives, seek to obtain RECs from additional projects, generate RECs from any REC-generating facilities it may own, or purchase RECs in the market. Ordinarily, Idaho Power does not receive the RECs associated with PURPA projects. However, an order issued by the IPUC on December 18, 2012, described below, provides that Idaho Power will own a portion of the RECs generated by some future PURPA projects. The required purchase of RECs to meet RPS requirements would increase Idaho Power's costs, which Idaho Power expects would be wholly or largely passed on to customers through rates and the power cost adjustment mechanism.

Renewable Energy Contracts: Idaho Power purchases wind power from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project -- the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of December 31, 2012, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of power from other renewable generation sources, such as biomass, solar, and small hydroelectric projects. As of December 31, 2012, Idaho Power had the number and nameplate capacity of signed CSPP-related agreements with terms ranging from one to 35 years set forth in the table below.

Status	**Number of CSPP Contracts**	**Nameplate Capacity (MW)**
On-line as of December 31, 2012	103	779
Contracted and projected to come on-line by year-end 2014	6	52

Pursuant to the requirements of Section 210 of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from CSPP facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements may result in Idaho Power acquiring energy it does not need at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's power supply cost mechanisms, and thus the primary impact of PURPA agreements is on customer rates.

PURPA Proceedings at the IPUC and OPUC: In response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011 the IPUC issued an order temporarily reducing the eligibility cap for PURPA projects entitled to published avoided cost rates from 10 aMW to 100 kW for wind and solar PURPA projects while the IPUC further investigated the implications of large projects disaggregating into smaller projects to qualify for higher published avoided cost rates and other benefits. On June 8, 2011, the IPUC issued an order maintaining the 100 kW eligibility cap for published avoided cost rates for wind and solar PURPA projects, and initiating additional proceedings to allow the parties to investigate and analyze the methodologies used in determining the appropriate power purchase price for PURPA projects. On that same date, the IPUC issued orders disapproving 13 PURPA wind power purchase agreements. Idaho Power estimates that the payments over the lives of the disapproved agreements would have totaled approximately $1.3 billion.

Idaho Power recently concluded proceedings at the IPUC relating to the determination of appropriate power purchase prices and other terms of PURPA power purchase agreements. On December 18, 2012, the IPUC issued an order addressing that and other aspects of PURPA contracts. The IPUC retained the existing 100 kW threshold for wind and solar projects eligible for published avoided cost rates and determined that for projects not eligible for published avoided cost rates, the price used for power purchase determinations would be updated annually based on updated natural gas prices and Idaho Power's updated load forecast. The IPUC also determined that RECs will be owned by the PURPA project developer for projects eligible for published avoided cost rates, and apportioned equally between the project developer and Idaho Power for other projects. The IPUC's order also provided that new projects will be paid for capacity based on the project's ability to deliver during peak hours and when Idaho Power's long-range plan shows the company is capacity deficient. Similar proceedings at the OPUC are also ongoing.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the environment. Current and pending environmental legislation relates to, among other items, climate change, greenhouse gas emissions and air quality, mercury and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species, and include, among others, the Clean Air Act (CAA), the CWA, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the ESA. In addition to imposing continuing compliance obligations and associated costs, these laws and regulations provide authority to levy substantial penalties for noncompliance, injunctive relief, and other sanctions. These laws and regulations are administered by federal agencies including the U.S. Environmental Protection Agency (EPA), the USFWS, and the National Oceanic and Atmospheric Administration (NOAA) (formerly the National Marine Fisheries Service), and state and local agencies. Idaho Power's three coal-fired power plants and three natural gas-fired combustion turbine power plants are also subject to many of these regulations. Idaho Power's 17 hydroelectric projects are also subject to a number of water discharge standards and other environmental requirements. Because these plants utilize different fuel sources, there is the likelihood that each plant will be subject to different regulations and requirements. See Part I, Item 2 - "Properties" in this report for further information on these power plants.

Compliance with current and future environmental laws and regulations may:

- increase the operating costs of generating plants;
- increase the construction costs and lead time for new facilities;
- require the modification of existing generating plants;
- require the curtailment or shut down of existing generating plants; or
- reduce the output from current generating facilities.

Current and future environmental laws and regulations will increase the cost of operating coal-fired power plants and constructing new facilities, will necessitate installation of additional pollution control devices at existing generating plants, or result in Idaho Power discontinuing operation of one or more coal-fired plants where operation becomes uneconomical. These regulations could, in turn, affect IDACORP's and Idaho Power's results of operations and financial condition if the costs associated with these environmental requirements and plant shut-downs cannot be fully recovered in rates on a timely basis. Part I - "Business - Environmental Regulation and Costs" in this report includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2013 to 2015. Given the uncertainty of future environmental regulations, Idaho Power is unable to predict its environmental-related expenditures beyond that time, though they could be substantial. IDACORP's and Idaho Power's boards of directors review environmental issues on a regular basis, including in connection with the strategic planning process.

In connection with its IRP process, Idaho Power has been conducting cost studies and scenario analysis to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal generation facilities, in light of the body of environmental laws and regulations impacting the cost of operating those plants. The Boardman coal facility was not included in the study because of the existing schedule to cease coal-fired operations at that plant by the end of 2020. Some of the future environmental control requirements for the Jim Bridger and Valmy plants are known; however, many potential additional requirements could arise from future regulations. In the analysis, the cost of future compliance was compared to the cost of replacement generation capacity provided by combined-cycle combustion turbine technology. Because of the speculative nature of many of the future requirements, the analysis was performed under a range of fuel pricing assumptions, carbon cost assumptions, plant upgrade and retirement costs, environmental regulation assumptions, and replacement costs. Idaho Power published the results of the study with its 2011 IRP update filed with the IPUC and OPUC in February 2013. Idaho Power concluded in its study that both plants should be retained in its resource portfolio. In addition to the estimated cost savings of retaining the plants under most scenarios, even with the installation of planned controls, retaining the plants also satisfies Idaho Power's desire to maintain a diversified portfolio of generation assets and fuel diversity that can mitigate risk associated with increases in natural gas prices. However, in the event significant additional operating and maintenance or capital expenditures are necessary at the Valmy plant as a result of new environmental requirements, Idaho Power will conduct a further review to determine whether such investments are economically appropriate, and whether conversion of the facility to a natural-gas fired plant would be appropriate.

Endangered Species and Fisheries Matters

Overview: The listing of a species of fish, wildlife, or plants as threatened or endangered under the ESA may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or relicense or operate its hydroelectric projects. When a species is added to the federal list of threatened and endangered species, it is protected from "take" and from being transported, traded, or sold. The term "take" under the ESA is interpreted to include "harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct." Section 7 of the ESA also provides that each federal agency shall ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of its critical habitat. The construction of generation, transmission, or distribution facilities and the licensing of Idaho Power's hydroelectric projects can be federally authorized actions that fall under Section 7 of the ESA. There are a number of threatened or endangered species within Idaho Power's service territory, which have the potential to impact the ability to construct, or the timing of construction, of infrastructure such as transmission lines. Further, there are a number of ESA listed fish and other aquatic species located in waterways in which Idaho Power has hydroelectric facilities, including fall Chinook salmon, bull trout, Bliss Rapids snail, and Snake River physa snail. To date, efforts to protect these and other listed species have not significantly affected generation levels at any of Idaho Power's hydroelectric facilities. However, the ongoing relicensing of the HCC presents endangered species and fisheries issues that may require generation or other operational adjustments. These adjustments may reduce the generation output or operating costs (and hence the economics) of the plants, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

ESA Developments Related to Specific Species:

Slickspot Peppergrass: This southwestern Idaho plant species was listed as threatened by the USFWS in 2009. In May 2011, the USFWS issued a proposed rule to designate critical habitat for the slickspot peppergrass and proposed to designate approximately 58,000 acres of critical habitat in four southeast Idaho counties. Approximately 98 percent of the plant species is located on federal land owned by the BLM and the U.S. Department of Defense. To date the USFWS has yet to issue a final designation of critical habitat. In August 2012, a federal district court in Idaho issued a decision vacating and remanding the USFWS's decision to list slickspot peppergrass. The BLM is now treating the species as a proposed species under ESA and will confer with the USFWS until a final decision is made. Parts of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines will cross BLM land upon which this species is located. The listing of the slickspot peppergrass will require that Idaho Power engage in an ESA Section 7 consultation with the USFWS, which will increase the cost of the transmission projects and potentially delay the receipt of a permit for construction.

Greater Sage Grouse: The greater sage grouse is considered a "candidate species" under the ESA, which allows land management agencies to implement additional conservation measures. In March 2010, the USFWS announced that listing of the greater sage grouse as threatened or endangered under the ESA is warranted but precluded by higher priority listing actions. On February 2, 2012, a federal district court in Idaho issued an order denying a request to expedite the listing of the greater sage grouse under the ESA. As a result, the USFWS has until 2015 to make a final listing determination under the ESA. On February 6, 2012, the same court issued an order holding that the BLM had violated the National Environmental Policy Act and other federal laws in connection with the granting of livestock grazing permit renewals in sage grouse habitat. Due to the presence of sage grouse in the vicinity of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines, siting of these projects has required more extensive, costly, and time consuming evaluation, permitting, and engineering. In the event the USFWS lists the greater sage grouse as threatened or endangered, federal agencies that may authorize rights-of-way to Idaho Power would be required to conduct a Section 7 consultation under the ESA for these transmission projects. Any required additional conservation measures may increase the costs of existing operations and impact the timing for siting, permitting, and constructing the Boardman-to-Hemingway and Gateway West transmission lines and other construction and transmission projects.

ESA Developments Related to Specific Projects:

Hells Canyon Relicensing Project: In 2007, the FERC requested initiation of formal consultation under the ESA with the NMFS (now the NOAA) and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has yet to be initiated and the NOAA and USFWS continue to gather and consider information relative to the effects of relicensing on relevant ESA listed species. Idaho Power continues to cooperate with the USFWS, the NOAA, and the FERC in an effort to address ESA concerns. In December 2004, Idaho Power and eleven other parties, including NOAA and USFWS, involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. At the conclusion of formal consultation and with the issuance of biological opinions by NOAA and USFWS and a license by the FERC, Idaho

Power may be required to further modify or adjust operations to comply with Section 7 of the ESA. The issuance of a final biological opinion during 2013 is unlikely.

Bliss and Lower Salmon Falls Projects: As part of a settlement agreement for the current FERC hydroelectric license, Idaho Power has finalized a snail protection plan for the Bliss and Lower Salmon Falls projects in cooperation with the USFWS. Idaho Power has filed applications with the FERC to amend the licenses for the projects that will maintain operating flexibility at both projects for the remainder of their licenses. The FERC requested formal consultation with the USFWS regarding the license amendments in July 2012. The ESA Section 7 consultation included two listed snails -- the Bliss Rapids snail and the Snake River physa snail. The USFWS filed its biological opinion with the FERC in November 2012.

Swan Falls Project: In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail was found in the area during the EIS review. While the biological opinion includes a provision for the incidental take of the snail, Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license.

Boardman-to-Hemingway and Gateway West Transmission Projects: As noted above, the existence of slickspot peppergrass and the greater sage grouse in the proposed routes for these projects is impacting, and Idaho Power expects it to continue to impact, the cost and timing of permitting and construction of the projects.

Climate Change and the Regulation of Greenhouse Gas (GHG) Emissions

Overview: Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand and energy loads;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general; and
- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. However, the regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units. Due in part to the uncertainty of future GHG regulations, in its 2011 IRP Idaho Power did not include any new conventional coal resources in its resource portfolios.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National and International GHG Initiatives: There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. In support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. Other communications from the Obama Administration have proposed the adoption of a clean energy standard in the U.S., calling for 80 percent of American energy to come from clean sources by 2035. Further, climate change regulation has been a recent priority of the U.S. Congress. In prior legislative sessions, legislation in both the U.S. House and Senate was introduced to enact a comprehensive climate change program, but these attempts were unsuccessful. At the same time, legislation has also been introduced seeking to amend the CAA to prohibit the EPA from promulgating regulations on the emissions of GHGs to address climate change and excluding GHGs from the definition of an "air pollutant" for purposes of addressing climate change. Neither areas of focus have culminated in legislation and have led to greater uncertainty as to the direction of GHG regulation.

At the same time, the EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. Lawsuits opposing EPA's endangerment finding and Tailoring Rule were unsuccessful. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the new GHG Tailoring Rules.

In addition, in April 2012, the EPA proposed New Source Performance Standards (NSPS) limiting CO_2 emissions from new electric utility generating units (EGUs) fired by fossil fuels. The proposed requirements, which are limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh. The EPA did not propose standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, if promulgated the new rule would impact the cost effectiveness of developing new generation units.

State and Regional GHG Initiatives: On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The mechanism was implemented in two phases, with Title V sources and entities with an air discharge permit required to start reporting 2009 emissions in 2010 and all other sources required to start reporting 2010 emissions in 2011. The Boardman coal-fired power plant, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel plants operating (i.e. Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

Idaho Power's Voluntary GHG Reduction Initiatives: Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated CO_2 emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 672, 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2011, 2010, 2009, 2008, and 2007, respectively.

In 2010, Idaho Power and Ida-West together ranked as the 37th lowest emitter of CO_2 per MWh produced and the 35th lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, and other entities using publicly reported 2010 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the 58th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

Public Nuisance-Related Suits for GHGs: In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court's decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

Clean Air Act Developments

Overview: In addition to the CAA developments related to GHG emissions described above, several other regulatory programs developed under the CAA impact Idaho Power. These include the final Utility Maximum Available Control Technology (MACT) rule, National Ambient Air Quality Standards (NAAQS), NSR/PSD Rules, and the Regional Haze Rule.

Final MACT Rule: The CAA requires the EPA to develop industry-based standards to control emissions of hazardous air pollutants, or HAPs. These standards are referred to as the MACT rules. In February 2012, the EPA issued final MACT rules to control emissions of mercury and other HAPs from coal- and oil-fired EGUs under the CAA and new NSPS for fossil fuel-fired EGUs. The regulations impose MACT and NSPS on all coal-fired EGUs and replace the former Clean Air Mercury Rule. Specifically, the regulations set numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrogen chloride, and mercury. In addition, the regulations impose a work practice standard for organic HAPs, including dioxins and furans. For the revised NSPS, for EGUs commencing construction of a new source after publication of the final rule, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. The compliance deadline for the new MACT rules could be as early as 2015. Mercury continuous emission monitoring systems have been installed on all of the coal-fired units at the Jim Bridger, Boardman, and Valmy generating plants in compliance with the NSPS rule. Idaho Power is reviewing the MACT final rule and is in the process of determining how these regulations will impact the Bridger, Boardman, and Valmy generating plants, including whether those coal-fired plants can meet HAP limits with current and planned control technologies. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, the new rules would impact the cost effectiveness of developing new EGUs.

NAAQS: The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. These six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans, or SIPs, based on attainment of these ambient air quality standards. Recent developments related to three of these pollutants - $PM_{2.5}$, NO_x, and SO_2 are relevant to Idaho Power.

- *Particular Matter ($PM_{2.5}$).* In 1997, the EPA adopted NAAQS for fine particulate matter of less than 2.5 micrometers in diameter ($PM_{2.5}$ standard), setting an annual limit of 15 micrograms per cubic meter ($\mu g/m^3$), calculated as a three-year average. In 2006, the EPA adopted a 24-hour NAAQS for $PM_{2.5}$. of 35 $\mu g/m^3$. All of the counties in Idaho, Nevada, Oregon, and Wyoming in which Idaho Power's power plants are located have been designated as "attainment" with these $PM_{2.5}$ standards. However, on December 14, 2012, the EPA released final revisions to the $PM_{2.5}$ NAAQS. The revised annual standard is 12 $\mu g/m^3$, calculated as a three-year average. The EPA retained the existing 24-hour standard of 35 $\mu g/m^3$. Now that the PM2.5 NAAQS has been finalized, states will make recommendations to the EPA regarding designations of attainment or non-attainment. States also will be required to review, modify, and supplement their SIPs, which could require the installation of additional controls and requirements for Idaho Power's coal-fired generation plants, depending on the level ultimately finalized. The revised NAAQS would also have an impact on the applicable air permitting requirements for new and modified facilities. The EPA has stated that it plans to issue nonattainment designations by late 2014, with states having until 2020 to comply with the standards.

- *NO_x.* In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a 1-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power owns or has an interest in a natural gas or coal-fired power plant as "unclassifiable/attainment" for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants. As the designations have not yet been finalized, as of the date of this report Idaho Power is unable to predict the impact of the NAAQS for NO_x on its operations. However, the costs of installation and implementation of any additional pollution reduction technology could be substantial.

- $\underline{SO_2}$. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Idaho, Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data.

Because the EPA has not yet completed the designation of areas as attaining or not attaining these new NAAQS, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations, though it does expect at least some increases in capital and operating costs from the standards.

Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any "Class I" (wilderness) areas. This includes all four units at the Jim Bridger and the Boardman coal-fired plants.

Jim Bridger Plant: In December 2009, the Wyoming Department of Environmental Quality (WDEQ) issued a RH BART permit to PacifiCorp as the operator of the Jim Bridger plant. The WDEQ determined that low NO_x burners with over-fire air is RH BART for NO_x for all four Bridger units and that RH BART is not required for SO_2 at the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install selective catalytic reduction (SCR) for NO_x control at Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by January 15, 2015 to install add-on NO_x controls at Jim Bridger Units 1 by 2022 and 2 by 2021. PacifiCorp has installed low NO_x burners and SO_2 scrubber upgrades at the plant. The SO_2 scrubber upgrade project has been completed on all four Jim Bridger units. Idaho Power spent approximately $1 million in 2012 for its share of these pollution control projects. Idaho Power's estimated share of the cost to install SCR on Jim Bridger Units 3 and 4 is $120 million. In addition to the installation costs, installation of SCR could require extended maintenance outages. Design and cost estimates for add-on NO_x controls at Jim Bridger Units 1 and 2 are not yet available.

In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp agreed to the timing and nature of controls described above. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan (RH SIP) that are consistent with the terms of the settlement agreement. In May 2012, the EPA proposed to partially reject Wyoming's regional haze SIP for NO_x reduction at the Jim Bridger plant, instead proposing to substitute the EPA's own RH BART determination and its Federal Implementation Plan (FIP). The EPA's primary proposal would result in an acceleration of the installation of SCR additions at Bridger Units 1 and 2 to within five years after the FIP, or a SIP revised to be consistent with the proposed FIP, is adopted by the EPA. In November 2012, the EPA approved the general provisions of the WDEQ's RH SIP. However, in December 2012 the EPA announced that it would re-propose the plant-specific NO_x control provisions of its RH FIP in March 2013 and would not finalize the RH FIP until September 2013.

Boardman Plant: Following the introduction of various plans and an extensive public process, in December 2010 the Oregon Environmental Quality Commission (OEQC) approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The rules implementing the plan were approved by the EPA and published in the Federal Register in July 2011, and require the installation of a number of emissions controls. The new rules repeal the OEQC's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more extensive suite of emissions controls. The estimated combined total capital cost of the required controls under the plan approved by the OEQC for controlling mercury, NO_x and SO_2 is approximately $60 million. Idaho Power is a 10 percent owner of the Boardman plant, and thus Idaho Power's estimated share of the capital cost is $6 million, which is in addition to normal capital expenditures and maintenance costs. As of December 31, 2012, Idaho Power had incurred charges of $3.8 million, including AFUDC, of its total estimated share of the capital cost for the new controls.

NSR / PSD: NSR/PSD is a preconstruction permitting program that requires a stationary source of air pollution to obtain a permit before beginning construction. The purpose of the program is to ensure that air quality is not significantly degraded by the addition of new and modified facilities, industrial boilers, and power plants. Under current NSR provisions of the CAA, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory equivalent before beginning the construction of a stationary source that will emit regulated pollutants, or before modifying an existing stationary source that will increase its emission levels. Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS under the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. As part of an industry-wide assessment of compliance with NSR and NSPS, EPA has sought information from a number of utilities regarding their coal-fired generating facilities. In 2003, the EPA sent information requests pursuant to the CAA to the Jim Bridger plant, seeking information relevant to NSR and NSPS compliance. Additional requests were received by the Valmy plant in 2009 and the Boardman plant in 2008, with a follow up request for information in 2009. In September 2010, the EPA issued a Notice of Violation to Portland General Electric Company, the operator of the Boardman plant, alleging that PGE violated the NSPS under Section 111 of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. To date, the EPA has not taken action on the Notice of Violation, and a related private lawsuit under the CAA was settled in 2011.

Potential Regulation of Coal Combustion Residuals (CCRs)

The Resource Conservation and Recovery Act is a federal statute regulating the generation, treatment, storage, and disposal of solid and hazardous wastes. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties. In response, in June 2010 the EPA proposed regulations governing the disposal and management of CCRs. The EPA requested comments on two options for regulating CCRs. The first option would regulate CCRs as a new "special waste" subject to many of the requirements for hazardous waste, while the second would regulate CCRs in a manner similar to typical solid waste, subject to fewer and less stringent requirements. To date the EPA has not issued final regulations. Both of the EPA's proposed options represent a shift toward more comprehensive and potentially more expensive requirements for CCR management and disposal. If this or other new legislation or regulations increase the cost of managing and disposing of CCRs or create additional liability with respect to historic disposal practices, they could have an adverse impact on Idaho Power's consolidated financial position, operations, or cash flows. However, the financial and operational consequences cannot be determined until final legislation is passed or regulations are issued.

Regulation of Polychlorinated Biphenyls (PCBs)

The Toxic Substances Control Act is a federal statute providing the EPA with the authority to, among other things, require use restrictions relating to chemical substances including PCBs. Generally, PCBs are prohibited from use, but some uses of PCBs - such as in electrical equipment - remain authorized under certain conditions. In April 2010, the EPA issued an advance notice of proposed rulemaking stating that it is considering revisiting the authorization allowing the continued use of PCBs in equipment. If new regulations require the replacement of existing equipment, they could have an adverse effect on IDACORP's and Idaho Power's financial condition and results of operations. However, the financial and operational consequences cannot be determined until final regulations are issued. Idaho Power currently records asset retirement obligation liabilities and associated regulatory assets for the estimated retirement costs of equipment containing PCBs. Final regulations could accelerate Idaho Power's estimated timing for the retirement of equipment with PCBs.

CWA - Potential Section 316(b) Regulation of Cooling Water Intake Structures

The CWA generally prohibits the discharge of any "pollutant" from a point source into waters of the United States without a permit. Pollutants are broadly defined to include changes in temperature. Section 316(b) of the CWA requires that National Pollutant Discharge Elimination System permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures employ the best technology available (BTA) to minimize harmful impacts on the environment, such as the removal of fish, fish larvae, marine mammals and other aquatic organisms from waters of the U.S.

In March 2011, the EPA issued a proposed rule that would establish requirements under Section 316(b) of the CWA for all existing power generation facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rule establishes national requirements applicable to cooling water intake structures at these facilities that reflect the BTA for minimizing adverse environmental impacts. An existing facility may choose one of two options for meeting BTA requirements for impingement mortality under this proposed rule. The owner or operator may monitor to show the specified performance standards for impingement mortality of fish and shellfish have been met, or they may demonstrate that the intake velocity meets specified design criteria. For entrainment mortality, this proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the BTA for entrainment mortality would be implemented at each facility. Since issuing the proposed rule, EPA has collected more than 80 studies from the public with additional biological data, some of which may help address the intent of the proposed rule to reduce damage to ecosystems while accommodating site-specific circumstances and providing cost-effective options for compliance. Based on the qualification criteria, Idaho Power expects that the new requirements would apply to the Jim Bridger plant, but it is unable to determine the potential increased costs that may result from implementation of the rule until the final rule is issued and cost studies are performed. The EPA has announced it intends to finalize the rules by June 2013.

Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See "Relicensing of Hydroelectric Projects" in this MD&A for additional information on the impact of the CWA on that relicensing effort.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with generally accepted accounting principles (GAAP), IDACORP's and Idaho Power's management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management's control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates. Management believes the accounting policies and estimates discussed below are the most critical to the portrayal of their financial condition and results of operations and require management's most difficult, subjective, or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power had recorded $1.2 billion of regulatory assets and $386 million of regulatory liabilities at December 31, 2012. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Either circumstance could have a material effect on Idaho Power's financial condition or results of operations.

Income Taxes

IDACORP and Idaho Power use judgment and estimation in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes for other items are provided for the temporary differences between the income tax and financial accounting treatment of such items. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax temporary differences where the prescribed regulatory accounting methods, or flow-through, direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

Refer to Note 1 - "Summary of Significant Accounting Policies" and Note 2 - "Income Taxes" to the consolidated financial statements included in this report for additional information relating to income taxes.

Asset Impairment

Available-for-sale Securities: Idaho Power is required to evaluate available-for-sale securities periodically to determine whether a decline in fair value below cost is other than temporary. If the decline in fair value is other than temporary, the cost of the investment is written down to fair value and the loss is recorded as a realized loss. Two significant factors that are considered when evaluating investments for impairment are the length of time and the extent to which the market value has been less than cost.

Idaho Power has investments in four mutual funds that experienced a significant decline in fair value in 2008. Idaho Power's investments had lost between 32 percent and 43 percent of their value, primarily during the stock market downturn in September and October 2008, and had been in loss positions from 6 to 12 months at December 31, 2008. Because of the severity of the declines in value, Idaho Power determined that the loss in value was other-than-temporary and recorded a pre-tax loss of $6.8 million in the fourth quarter of 2008. At December 31, 2012 and 2011, the fair values of these investments were at or above their new cost bases and no impairment was recorded.

Equity-Method Investments: IFS has affordable housing investments with a net book value of $51 million at December 31, 2012, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for one investment which is consolidated, these investments are accounted for under the equity method of accounting and have a net book value of $12 million. The standard for determining whether impairment must be recorded for these investments is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses are performed on these investments when indicators of impairment are noted. An immaterial impairment was recorded on one of the Ida-West joint ventures in 2011, and no impairments were recorded in 2012 or in 2010. These estimates required IDACORP to make assumptions about future revenues, cash flows, and other items that are inherently uncertain. Actual results could vary significantly from the assumptions used, and the impact of such variations could be material.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future stock market performance, changes in interest rates, and other factors used to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2012, with maturities matching the projected cash outflows of the plans. The discount rate used to calculate the 2013 pension expense will be decreased to 4.2 percent from the 4.9 percent used in 2012.

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 Idaho Power believes 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 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. The long-term rate of return used to calculate the 2013 pension expense will be 7.75 percent, which is the same assumption as was used for 2012.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $51 million, $39 million, and $39 million for the years ended December 31, 2012, 2011, and 2010, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2013, gross pension and other postretirement benefit costs are expected to total approximately $57 million, which takes into account the change in the discount rate noted above. No changes were made to the other key assumptions used in the actuarial calculation.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in the discount rate and rate-of-return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2013	2012	2013	2012
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (6.9)	$ (5.7)	$ (2.5)	$ (2.2)
Effect of 0.5% rate decrease on net periodic benefit cost	8.0	6.6	2.4	2.2

Additionally a 0.5 percent increase in the plans' discount rates would have resulted in a $67 million decrease in the combined benefit obligations of the plans as of December 31, 2012. A 0.5 percent decrease in the plans' discount rates would have resulted in a $76 million increase in the combined benefit obligations of the plans as of December 31, 2012.

Idaho Power made contributions of $60 million, $18.5 million, and $44.3 million to the pension plan in 2010, 2011, and 2012 respectively. Idaho Power's required contributions to the pension plan during 2013 are estimated to be zero. Under the SMSP, Idaho Power makes payments directly to participants in the plan. Benefit payments are expected to be $3.7 million in 2013 and averaged $3.3 million per year from 2010 to 2012. Postretirement benefit plan contributions are expected to be $0.3 million in 2013, and averaged $0.9 million from 2010 to 2012.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2012, a total of $65 million of expense was deferred as a regulatory asset. Approximately $26 million is expected to be deferred in 2013. Idaho Power recorded pension expense in 2012, 2011, and 2010 of $34 million, $34 million, and $5 million, respectively.

Refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated, no accrual is recorded but disclosure of the contingency in the notes to the financial statements is required. Gain contingencies are not recorded until realized.

IDACORP and Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria have been met, liabilities have been recorded. Estimates of this nature are highly subjective and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

There have been no recently issued accounting pronouncements that have had or are expected to have a material impact on IDACORP's or Idaho Power's results of operations or financial condition. See Note 1 - "Summary of Significant Accounting Policies" to the consolidated financial statements included in this report for a summary of significant accounting policies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk, and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments, and derivative commodity instruments sensitive to changes in interest rates, commodity prices, and equity prices that were held at December 31, 2012.

Interest Rate Risk

IDACORP and Idaho Power manage interest expense and short- and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may be used to achieve the desired combination.

***Variable Rate Debt*:** As of December 31, 2012, IDACORP and Idaho Power had $96.6 million and $24.1 million, respectively, in net floating-rate debt. The fair market value of this debt was $96.6 million and $24.1 million, respectively. Assuming no change in financial structure, if variable interest rates were to average one percentage-point higher than the average rate on December 31, 2012, interest rate expense would increase and pre-tax earnings would decrease by approximately $1.0 million for IDACORP and $0.2 million for Idaho Power.

***Fixed Rate Debt*:** As of December 31, 2012, IDACORP and Idaho Power each had $1.5 billion in fixed rate debt, with a fair market value equal to $1.8 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $147 million for both IDACORP and Idaho Power if interest rates were to decline by one percentage point from their December 31, 2012 levels.

Commodity Price Risk

Idaho Power's exposure to changes in commodity prices is related to its ongoing utility operations that produce electricity to meet the demand of its retail electric customers. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. Idaho Power anticipates that the additional volume of natural gas needed to operate the Langley Gulch power plant will increase its exposure in the future to natural gas commodity price risk. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of production. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

Idaho Power's exposure to commodity price risk is largely offset by the PCA mechanisms in Idaho and Oregon. Therefore, the primary objectives of Idaho Power's energy purchase and sale activity are to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power's Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power's Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power's strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power does not engage in trading activities for non-retail purposes.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The Power Supply business unit produces and evaluates projections of the operating plan based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. Idaho Power representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the board of directors for approval.

Credit Risk

Idaho Power is subject to credit risk based on its activity with market counterparties. Idaho Power is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy, or complete financial settlement for market activities. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash, or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2012, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade, Idaho Power could be subject to requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2012, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7.2 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Idaho Power is obligated to provide service to all electric customers within its service area. Credit risk for Idaho Power's retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC or OPUC. Idaho Power records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. Idaho Power will continue to monitor the impact of the current economic conditions on nonpayment from customers and will make any necessary adjustments to its provision for uncollectible accounts.

Idaho utility customer relations rules prohibit Idaho Power from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly, or infirm persons. Idaho Power's provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC or OPUC regulations.

Equity Price Risk

IDACORP and Idaho Power are exposed to price fluctuations in equity markets, primarily through their defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity investments at Idaho Power. During 2012, the fair value of the defined benefit pension plan's assets increased; however, increases in the benefit liabilities were greater than the increases in the plan's assets, therefore resulting in an increase in future amounts required to be contributed to the plan. A hypothetical ten percent decrease in equity prices would result in an approximate $3.2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities as of December 31, 2012.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 937,765	$ 834,545	$ 870,371
Off-system sales	61,534	101,602	78,133
Other revenues	77,426	86,581	84,548
Total electric utility revenues	1,076,725	1,022,728	1,033,052
Other	3,937	4,028	2,977
Total operating revenues	1,080,662	1,026,756	1,036,029
Operating Expenses:			
Electric utility:			
Purchased power	196,935	163,336	143,769
Fuel expense	159,413	131,542	159,673
Power cost adjustment	(61,090)	38,497	51,226
Other operations and maintenance	349,033	338,640	293,925
Energy efficiency programs	27,300	37,663	44,184
Depreciation	123,941	119,789	115,921
Taxes other than income taxes	30,489	28,895	24,046
Total electric utility expenses	826,021	858,362	832,744
Other	12,039	13,042	11,474
Total operating expenses	838,060	871,404	844,218
Operating Income	242,602	155,352	191,811
Allowance for Equity Funds Used During Construction	22,433	25,484	16,551
(Losses) Earnings of Unconsolidated Equity-Method Investments	(328)	798	3,008
Other Income, Net	4,209	4,621	5,473
Interest Expense:			
Interest on long-term debt	78,922	79,349	80,490
Other interest	6,876	5,510	5,299
Allowance for borrowed funds used during construction	(11,929)	(13,333)	(10,675)
Total interest expense, net	73,869	71,526	75,114
Income Before Income Taxes	195,047	114,729	141,729
Income Tax Expense (Benefit)	26,113	(52,133)	(731)
Net Income	168,934	166,862	142,460
Adjustment for (income) loss attributable to noncontrolling interests	(173)	(169)	338
Net Income Attributable to IDACORP, Inc.	$ 168,761	$ 166,693	$ 142,798
Weighted Average Common Shares Outstanding - Basic (000's)	49,930	49,457	48,193
Weighted Average Common Shares Outstanding - Diluted (000's)	50,010	49,558	48,340
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.38	$ 3.37	$ 2.96
Earnings Attributable to IDACORP, Inc. - Diluted	$ 3.37	$ 3.36	$ 2.95
Dividends Declared Per Share of Common Stock	$ 1.37	$ 1.20	$ 1.20

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Net Income	$ 168,934	$ 166,862	$ 142,460
Other Comprehensive Income:			
Net unrealized holding gains (losses) arising during the year, net of tax of $1,006, ($257), and $738	1,567	(400)	1,149
Unfunded pension liability adjustment, net of tax of ($4,532), ($1,062), and ($1,573)	(7,061)	(1,654)	(2,450)
Total Comprehensive Income	163,440	164,808	141,159
Comprehensive (income) loss attributable to noncontrolling interests	(173)	(169)	338
Comprehensive Income Attributable to IDACORP, Inc.	$ 163,267	$ 164,639	$ 141,497

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2012	December 31, 2011
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 26,527	$ 27,813
Receivables:		
Customer (net of allowance of $1,551 and $1,239, respectively)	66,111	66,296
Other (net of allowance of $322 and $196, respectively)	23,608	8,197
Income taxes receivable	1,753	421
Accrued unbilled revenues	51,448	46,441
Materials and supplies (at average cost)	51,037	46,490
Fuel stock (at average cost)	42,388	47,865
Prepayments	12,823	12,405
Deferred income taxes	56,532	16,159
Current regulatory assets	30,078	34,279
Other	4,948	4,606
Total current assets	367,253	310,972
Investments	189,020	199,931
Property, Plant and Equipment:		
Utility plant in service	4,915,772	4,466,873
Accumulated provision for depreciation	(1,703,159)	(1,677,609)
Utility plant in service - net	3,212,613	2,789,264
Construction work in progress	298,470	591,475
Utility plant held for future use	7,101	6,974
Other property, net of accumulated depreciation	17,847	18,877
Property, plant and equipment - net	3,536,031	3,406,590
Other Assets:		
American Falls and Milner water rights	17,909	20,015
Company-owned life insurance	22,646	24,060
Regulatory assets	1,132,960	953,068
Long-term receivables (net of allowance of $1,260 and $2,743, respectively)	4,437	5,621
Other	49,260	40,352
Total other assets	1,227,212	1,043,116
Total	$ 5,319,516	$ 4,960,609

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2012	December 31, 2011
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 71,064	$ 101,064
Notes payable	69,700	54,200
Accounts payable	90,165	81,769
Income taxes accrued	1,005	505
Interest accrued	22,311	21,797
Accrued compensation	42,343	39,726
Current regulatory liabilities	30,277	29,738
Other	24,438	39,448
Total current liabilities	351,303	368,247
Other Liabilities:		
Deferred income taxes	894,616	772,047
Regulatory liabilities	355,362	332,057
Pension and other postretirement benefits	423,409	363,209
Other	65,228	75,805
Total other liabilities	1,738,615	1,543,118
Long-Term Debt	1,466,632	1,387,550
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 50,158,486 and 49,964,172 shares issued, respectively)	834,922	828,389
Retained earnings	940,968	840,916
Accumulated other comprehensive loss	(17,116)	(11,622)
Treasury stock (1,817 and 12,177 shares at cost, respectively)	(21)	(29)
Total IDACORP, Inc. shareholders' equity	1,758,753	1,657,654
Noncontrolling interests	4,213	4,040
Total equity	1,762,966	1,661,694
Total	$ 5,319,516	$ 4,960,609

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Operating Activities:			
Net income	$ 168,934	$ 166,862	$ 142,460
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	128,611	124,659	121,849
Deferred income taxes and investment tax credits	26,293	(52,913)	41,742
Changes in regulatory assets and liabilities	(53,468)	68,045	46,510
Pension and postretirement benefit plan expense	45,230	45,223	14,728
Contributions to pension and postretirement benefit plans	(47,695)	(22,088)	(65,601)
Losses (earnings) of unconsolidated equity-method investments	328	(798)	(3,008)
Distributions from unconsolidated equity-method investments	18,546	2,500	6,530
Allowance for equity funds used during construction	(22,433)	(25,484)	(16,551)
Other non-cash adjustments to net income, net	5,919	4,487	3,061
Change in:			
Accounts receivable and prepayments	(3,919)	(2,232)	14,243
Accounts payable and other accrued liabilities	10,580	5,428	4,014
Taxes accrued/receivable	(604)	15,113	(14,216)
Other current assets	(4,077)	(19,684)	3,848
Other current liabilities	(8,500)	2,171	13,682
Other assets	(7,064)	4,330	(3,662)
Other liabilities	(7,412)	(5,376)	(4,229)
Net cash provided by operating activities	249,269	310,243	305,400
Investing Activities:			
Additions to property, plant and equipment	(239,761)	(337,765)	(338,252)
Proceeds from the sale of utility assets	—	—	18,982
Proceeds from the sale of emission allowances and RECs	2,739	6,314	6,408
Investments in affordable housing	(139)	(1,558)	(13,390)
Investments in unconsolidated affiliates	—	(2,645)	—
Purchase of available-for-sale securities	(7,000)	—	(7,000)
Other	340	3,296	4,918
Net cash used in investing activities	(243,821)	(332,358)	(328,334)
Financing Activities:			
Issuance of long-term debt	150,000	—	200,000
Retirement of long-term debt	(101,064)	(121,064)	(1,064)
Dividends on common stock	(68,928)	(59,668)	(57,872)
Net change in short-term borrowings	15,500	(12,700)	13,150
Issuance of common stock	4,882	17,501	48,644
Acquisition of treasury stock	(2,062)	(1,933)	(869)
Other	(5,062)	(885)	(3,365)
Net cash (used in) provided by financing activities	(6,734)	(178,749)	198,624
Net (decrease) increase in cash and cash equivalents	(1,286)	(200,864)	175,690
Cash and cash equivalents at beginning of the year	27,813	228,677	52,987
Cash and cash equivalents at end of the year	$ 26,527	$ 27,813	$ 228,677
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Income taxes	$ 1,451	$ (12,405)	$ (27,112)
Interest (net of amount capitalized)	$ 70,887	$ 70,969	$ 69,049
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 26,882	$ 26,331	$ 33,949
Investments in affordable housing	$ —	$ —	$ 1,509

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 828,389	$ 807,842	$ 756,475
Issued	4,882	17,501	48,644
Other	1,651	3,046	2,723
Balance at end of year	834,922	828,389	807,842
Retained Earnings:			
Balance at beginning of year	840,916	733,879	649,180
Net income attributable to IDACORP, Inc.	168,761	166,693	142,798
Common stock dividends ($1.37, $1.20, and $1.20 per share, respectively)	(68,709)	(59,656)	(58,099)
Balance at end of year	940,968	840,916	733,879
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(11,622)	(9,568)	(8,267)
Net unrealized holding gain (loss) on securities (net of tax)	1,567	(400)	1,149
Unfunded pension liability adjustment (net of tax)	(7,061)	(1,654)	(2,450)
Balance at end of year	(17,116)	(11,622)	(9,568)
Treasury Stock:			
Balance at beginning of year	(29)	(40)	(53)
Issued	2,070	1,944	882
Acquired	(2,062)	(1,933)	(869)
Balance at end of year	(21)	(29)	(40)
Total IDACORP, Inc. shareholders' equity at end of year	1,758,753	1,657,654	1,532,113
Noncontrolling Interests:			
Balance at beginning of year	4,040	3,871	4,209
Net income (loss) attributable to noncontrolling interests	173	169	(338)
Balance at end of year	4,213	4,040	3,871
Total equity at end of year	$ 1,762,966	$ 1,661,694	$ 1,535,984

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Operating Revenues:			
General business	$ 937,765	$ 834,545	$ 870,371
Off-system sales	61,534	101,602	78,133
Other revenues	77,426	86,581	84,548
Total operating revenues	1,076,725	1,022,728	1,033,052
Operating Expenses:			
Operation:			
Purchased power	196,935	163,336	143,769
Fuel expense	159,413	131,542	159,673
Power cost adjustment	(61,090)	38,497	51,226
Other operations and maintenance	349,033	338,640	293,925
Energy efficiency programs	27,300	37,663	44,184
Depreciation	123,941	119,789	115,921
Taxes other than income taxes	30,489	28,895	24,046
Total operating expenses	826,021	858,362	832,744
Income from Operations	250,704	164,366	200,308
Other Income (Expense):			
Allowance for equity funds used during construction	22,433	25,484	16,551
Earnings of unconsolidated equity-method investments	9,412	9,018	11,281
Other expense, net	(4,982)	(4,462)	(2,868)
Total other income	26,863	30,040	24,964
Interest Charges:			
Interest on long-term debt	78,922	79,349	80,490
Other interest	6,436	5,039	4,110
Allowance for borrowed funds used during construction	(11,929)	(13,333)	(10,675)
Total interest charges	73,429	71,055	73,925
Income Before Income Taxes	204,138	123,351	151,347
Income Tax Expense (Benefit)	35,970	(41,399)	10,713
Net Income	$ 168,168	$ 164,750	$ 140,634

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Net Income	$ 168,168	$ 164,750	$ 140,634
Other Comprehensive Income:			
Net unrealized holding gains (losses) arising during the year, net of tax of $1,006, ($257), and $738	1,567	(400)	1,149
Unfunded pension liability adjustment, net of tax of ($4,532), ($1,062), and ($1,573)	(7,061)	(1,654)	(2,450)
Total Comprehensive Income	$ 162,674	$ 162,696	$ 139,333

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2012	2011
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$ 4,915,772	$ 4,466,873
Accumulated provision for depreciation	(1,703,159)	(1,677,609)
In service - net	3,212,613	2,789,264
Construction work in progress	298,470	591,475
Held for future use	7,101	6,974
Electric plant - net	3,518,184	3,387,713
Investments and Other Property	128,145	128,674
Current Assets:		
Cash and cash equivalents	17,251	19,316
Receivables:		
Customer (net of allowance of $1,551 and $1,239, respectively)	66,111	66,296
Other (net of allowance of $322 and $196, respectively)	20,618	8,011
Income taxes receivable	2,559	4,644
Accrued unbilled revenues	51,448	46,441
Materials and supplies (at average cost)	51,037	46,490
Fuel stock (at average cost)	42,388	47,865
Prepayments	12,688	12,274
Deferred income taxes	48,774	14,099
Current regulatory assets	30,078	34,279
Other	4,950	4,606
Total current assets	347,902	304,321
Deferred Debits:		
American Falls and Milner water rights	17,909	20,015
Company-owned life insurance	22,646	24,060
Regulatory assets	1,132,960	953,068
Other	47,965	38,988
Total deferred debits	1,221,480	1,036,131
Total	$ 5,215,711	$ 4,856,839

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2012	2011
	(thousands of dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	712,258	704,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	834,732	735,304
Accumulated other comprehensive loss	(17,116)	(11,622)
Total common stock equity	1,625,654	1,524,220
Long-term debt	1,466,632	1,387,550
Total capitalization	3,092,286	2,911,770
Current Liabilities:		
Long-term debt due within one year	71,064	101,064
Accounts payable	89,651	81,054
Accounts payable to related parties	252	1,512
Interest accrued	22,311	21,797
Accrued compensation	42,282	39,670
Current regulatory liabilities	30,277	29,738
Other	23,813	38,777
Total current liabilities	279,650	313,612
Deferred Credits:		
Deferred income taxes	1,001,877	863,044
Regulatory liabilities	355,362	332,057
Pension and other postretirement benefits	423,409	363,209
Other	63,127	73,147
Total deferred credits	1,843,775	1,631,457
Commitments and Contingencies		
Total	$ 5,215,711	$ 4,856,839

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Operating Activities:			
Net income	$ 168,168	$ 164,750	$ 140,634
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	128,009	124,028	121,219
Deferred income taxes and investment tax credits	48,255	(57,929)	78,631
Changes in regulatory assets and liabilities	(53,467)	68,045	46,509
Pension and postretirement benefit plan expense	45,230	45,223	14,728
Contributions to pension and postretirement benefit plans	(47,695)	(22,088)	(65,601)
Earnings of unconsolidated equity-method investments	(9,412)	(9,018)	(11,281)
Distributions from unconsolidated equity-method investments	17,921	—	4,755
Allowance for equity funds used during construction	(22,433)	(25,484)	(16,551)
Other non-cash adjustments to net income, net	236	1,159	(576)
Change in:			
Accounts receivables and prepayments	(4,519)	(2,468)	13,118
Accounts payable	10,762	5,357	4,080
Taxes accrued/receivable	3,301	19,217	(9,392)
Other current assets	(4,077)	(19,684)	3,848
Other current liabilities	(8,506)	2,169	13,674
Other assets	(7,064)	4,330	(3,662)
Other liabilities	(6,856)	(5,117)	(3,711)
Net cash provided by operating activities	257,853	292,490	330,422
Investing Activities:			
Additions to utility plant	(239,761)	(337,765)	(338,252)
Proceeds from the sale of utility assets	—	—	18,982
Proceeds from the sale of emission allowances and RECs	2,739	6,314	6,408
Investments in unconsolidated affiliates	—	(2,645)	—
Purchase of available for sale securities	(7,000)	—	(7,000)
Other	367	2,665	4,366
Net cash used in investing activities	(243,655)	(331,431)	(315,496)
Financing Activities:			
Issuance of long-term debt	150,000	—	200,000
Retirement of long-term debt	(101,064)	(121,064)	(1,064)
Dividends on common stock	(68,740)	(59,705)	(58,070)
Capital contribution from parent	7,500	16,000	50,000
Other	(3,959)	(1,207)	(3,184)
Net cash (used in) provided by financing activities	(16,263)	(165,976)	187,682
Net (decrease) increase in cash and cash equivalents	(2,065)	(204,917)	202,608
Cash and cash equivalents at beginning of the year	19,316	224,233	21,625
Cash and cash equivalents at end of the year	$ 17,251	$ 19,316	$ 224,233
Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$ (14,558)	$ (759)	$ (57,378)
Interest (net of amount capitalized)	$ 70,447	$ 70,491	$ 67,868
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 26,882	$ 26,331	$ 33,949

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 735,304	$ 630,259	$ 547,695
Net Income	168,168	164,750	140,634
Dividends on Common Stock	(68,740)	(59,705)	(58,070)
Retained Earnings, End of Year	$ 834,732	$ 735,304	$ 630,259

The accompanying notes are an integral part of these statements.

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This Annual Report on Form 10-K is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (Idaho Power). Therefore, the Notes to the Consolidated Financial Statements apply to both IDACORP and Idaho Power. However, Idaho Power makes no representation as to the information relating to IDACORP's other operations.

Nature of Business

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

IDACORP's other wholly-owned subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), which is the former limited partner of, and current successor by merger to, IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. Intercompany balances have been eliminated in consolidation. Investments in subsidiaries that the companies do not control and investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

The entities that IDACORP and Idaho Power consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2012, Marysville had approximately $20 million of assets, primarily a hydroelectric plant, and approximately $15 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is the primary beneficiary because the ownership of the intercompany note and the EEC note result in it controlling the entity. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

The BCC joint venture is also a VIE, but because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner, the company is not the primary beneficiary. The carrying value of BCC was $94 million at December 31, 2012, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $66 million guarantee for mine reclamation costs, which is discussed further in Note 9.

IFS's investments in affordable housing and other real estate are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 5 to 99 percent and were acquired between 1996 and 2010. As a limited partner, IFS does not control these entities and they are not consolidated. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $51 million at December 31, 2012.

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

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Other receivables, primarily notes receivable from business transactions, are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that IDACORP or Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2012 and 2011. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options, and swaps are used to manage exposure to commodity price risk in the electricity and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet unless they are designated as normal purchases and normal sales. Idaho Power's physical forward contracts are designated as normal purchases and normal sales with the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities. The objective of Idaho Power's risk management program is to mitigate the price risk associated with the purchase and sale of electricity and natural gas. Because of Idaho Power's regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, AFUDC, and indirect charges for engineering, supervision, and similar overhead items. Repair and maintenance costs associated with planned major maintenance are expensed as the costs are incurred, as are maintenance and repairs of property and replacements and renewals of items determined to be less than units of property. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.75 percent in 2012, 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 2012, 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, as discussed above for the Hells Canyon Complex relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power's weighted-average monthly AFUDC rates for 2012, 2011, and 2010 were 7.7 percent, 7.8 percent, and 8.0 percent, respectively.

Income Taxes

IDACORP and Idaho Power account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method (commonly referred to as normalized accounting), deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities at the beginning and end of the period. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not provide deferred income taxes for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are provided for other temporary differences unless accounted for using flow-through.

The state of Idaho allows a three percent investment tax credit on qualifying plant additions. Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties. Credits earned on non-regulated assets or investments are recognized in the year earned.

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan. The following table presents IDACORP's and Idaho Power's accumulated other comprehensive loss balance at December 31 (net of tax):

	2012	2011
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 4,136	$ 2,569
Senior Management Security Plan	(21,252)	(14,191)
Total	$ (17,116)	$ (11,622)

Other Accounting Policies

Debt discount, expense, and premium are deferred and are being amortized over the terms of the respective debt issues.

Reclassifications

Certain prior year amounts on the IDACORP consolidated statements of income have been reclassified to conform to the current year presentation. In the current year, the allowance for equity funds used during construction has been classified to a separate line item. Previously, such amounts had been classified within the line item captioned "Other Income, Net." In addition, the components of the line item "Other interest, net of AFUDC" have been expanded to present a separate line item for the portion attributable to the allowance for borrowed funds used during construction. See also Note 18 concerning a corrective reclassification made to certain 2011 and 2010 operating expenses.

To conform with IDACORP's and Idaho Power's 2012 consolidated balance sheet presentation, certain employee compensation liabilities as of December 31, 2011, have been reclassified from "Accounts payable" and "Other" current liabilities and are now reported in the accompanying 2011 consolidated balance sheet in a separate line item captioned "Accrued compensation."

Previously reported net income, cash flows, and shareholders' equity were not affected by these reclassifications.

2. INCOME TAXES

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
			(thousands of dollars)			
Federal income tax expense at 35% statutory rate	$ 68,206	$ 40,096	$ 49,723	$ 71,448	$ 43,173	$ 52,972
Change in taxes resulting from:						
AFUDC	(12,027)	(13,586)	(9,529)	(12,027)	(13,586)	(9,529)
Capitalized interest	5,075	6,465	3,674	5,075	6,465	3,674
Investment tax credits	(3,267)	(3,355)	(3,378)	(3,267)	(3,355)	(3,378)
Removal costs	(2,697)	(2,244)	(2,850)	(2,697)	(2,244)	(2,850)
Capitalized overhead costs	(8,750)	(5,950)	(3,500)	(8,750)	(5,950)	(3,500)
Capitalized repair costs	(19,250)	(14,000)	(10,500)	(19,250)	(14,000)	(10,500)
Tax method change – uniform capitalization	—	—	(65,333)	—	—	(65,333)
Tax method change – capitalized repairs	(7,845)	—	(44,466)	(7,845)	—	(44,466)
Uncertain tax positions – established	—	—	74,436	—	—	74,436
Uncertain tax positions – settled	—	(63,138)	(1,138)	—	(63,138)	(1,138)
State income taxes, net of federal benefit	7,503	1,375	4,565	7,646	1,846	5,074
Depreciation	14,398	14,100	13,138	14,398	14,100	13,138
Affordable housing tax credits	(5,493)	(6,438)	(7,309)	—	—	—
Other, net	(9,740)	(5,458)	1,736	(8,761)	(4,710)	2,113
Total income tax expense (benefit)	$ 26,113	$ (52,133)	$ (731)	$ 35,970	$ (41,399)	$ 10,713
Effective tax rate	13.4%	(45.5)%	(0.5)%	17.6%	(33.6)%	7.1%

The items comprising income tax expense (benefit) are as follows:

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
			(thousands of dollars)			
Income taxes current:						
Federal	$ 547	$ (10)	$ (39,518)	$ (13,131)	$ 9,234	$ (62,338)
State	306	790	(5,960)	846	7,296	(5,580)
Total	853	780	(45,478)	(12,285)	16,530	(67,918)
Income taxes deferred:						
Federal	26,026	23,940	(22,582)	48,839	24,559	10,902
State	(9,822)	(1,285)	(4,436)	(9,640)	(6,920)	(4,036)
Total	16,204	22,655	(27,018)	39,199	17,639	6,866
Uncertain tax positions:						
Federal	—	(66,225)	65,222	—	(66,225)	65,222
State	—	(8,211)	8,076	—	(8,211)	8,076
Total	—	(74,436)	73,298	—	(74,436)	73,298
Investment tax credits:						
Deferred	12,323	2,223	1,845	12,323	2,223	1,845
Restored	(3,267)	(3,355)	(3,378)	(3,267)	(3,355)	(3,378)
Total	9,056	(1,132)	(1,533)	9,056	(1,132)	(1,533)
Total income tax expense (benefit)	$ 26,113	$ (52,133)	$ (731)	$ 35,970	$ (41,399)	$ 10,713

The components of the net deferred tax liability are as follows:

	IDACORP		Idaho Power	
	2012	2011	2012	2011
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 55,085	$ 45,473	$ 55,085	$ 45,473
Advances for construction	3,010	5,118	3,010	5,118
Deferred compensation	23,556	22,172	23,463	22,067
Advanced payments	17,856	12,958	17,856	12,958
Power cost adjustments	—	1,711	—	1,711
Tax credits	145,710	119,310	21,217	8,571
Net operating losses	53,254	—	47,351	—
Revenue sharing	2,796	10,594	2,796	10,594
Retirement benefits	146,546	122,445	146,546	122,445
Other	5,834	5,380	4,340	3,758
Total	453,647	345,161	321,664	232,695
Deferred tax liabilities:				
Property, plant and equipment	406,283	333,335	406,283	333,335
Regulatory assets	677,795	599,992	677,795	599,992
Conservation programs	5,114	3,464	5,114	3,464
Power cost adjustments	16,832	—	16,832	—
Fixed cost adjustment	5,246	5,652	5,246	5,652
Partnership investments	19,178	19,749	7,970	6,181
Retirement benefits	142,270	122,712	142,270	122,712
Other	19,013	16,145	13,257	10,304
Total	1,291,731	1,101,049	1,274,767	1,081,640
Net deferred tax liabilities	$ 838,084	$ 755,888	$ 953,103	$ 848,945

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP. See Note 1 for further discussion of accounting policies related to income taxes.

Tax Credit Carryforwards and Net Operating Loss Carryforwards

As of December 31, 2012, IDACORP had $107 million of general business credit and $1 million of alternative minimum tax credit carryforwards for federal income tax purposes and $38 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2032, and the Idaho investment tax credit expires from 2019 to 2026. IDACORP has a $156 million federal net operating loss carryforward with expiration periods from 2031 to 2032.

Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits for IDACORP and Idaho Power is as follows (in thousands of dollars):

	2012	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

IDACORP and Idaho Power recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Both companies recognized no interest expense in 2012, a net reduction of $0.2 million in 2011, and $0.2 million of interest expense in 2010. Accrued interest at both companies was zero as of December 31, 2012 and 2011, and $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 for examination are 2012 for federal and 2009-2012 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2012, the IRS completed its examination of IDACORP's 2011 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no material tax uncertainties for 2012 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

In 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. The capitalized repairs method is effectively settled and no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

In the third quarter of 2012 Idaho Power completed an income tax accounting method change for its 2011 tax year related to a portion of the capitalized repairs method. The change was made pursuant to Revenue Procedure 2011-43 to bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric transmission and distribution property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP's 2011 consolidated federal income tax return. The IRS approved the method change prior to the filing of the return as part of IDACORP's 2011 CAP examination. A $7.8 million tax benefit was recognized in 2012 for the filed deduction related to the cumulative method change adjustment for years prior to 2011.

For the year ended December 31, 2012, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $21.5 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized the remaining $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2012, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $9.8 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Cash Impacts of Tax Method Changes

In 2011, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. 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, IDACORP and Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $33 million and $42 million, respectively. 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 $45 million and $65 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

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Total as of December 31, 2012	2011
Regulatory Assets:					
Income taxes		$ —	$ 677,795	$ 677,795	$ 603,772
Unfunded postretirement benefits[2]		—	308,850	308,850	262,503
Pension expense deferrals[3]		50,036	14,959	64,995	58,044
Energy efficiency program costs[3]		17,085	—	17,085	15,956
Power supply costs[3]	Varies	60,680	—	60,680	8,490
Fixed cost adjustment[3]	2013-2014	13,418	—	13,418	14,457
Asset retirement obligations[4]		—	15,411	15,411	15,557
Mark-to-market liabilities[5]		—	1,055	1,055	4,707
Other	2013-2021	1,202	2,547	3,749	3,861
Total		$ 142,421	$ 1,020,617	$ 1,163,038	$ 987,347
Regulatory Liabilities:					
Income taxes		$ —	$ 55,085	$ 55,085	$ 49,253
Removal costs[4]		—	168,651	168,651	163,173
Investment tax credits		—	79,897	79,897	70,841
Deferred revenue-AFUDC[3]		29,404	16,269	45,673	33,145
Energy efficiency program costs[3]		4,130	—	4,130	—
Power supply costs[3]	Varies	17,778	—	17,778	13,121
Settlement agreement sharing mechanism[3]	2013-2014	7,151	—	7,151	27,099
Mark-to-market assets[5]		—	4,579	4,579	3,754
Other		2,439	256	2,695	1,409
Total		$ 60,902	$ 324,737	$ 385,639	$ 361,795

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) These items are discussed in more detail in this Note 3.
(4) Asset retirement obligations and removal costs are discussed in Note 13.
(5) Mark-to-market assets and liabilities are discussed in Note 16.

Idaho Power's regulatory assets and liabilities are amortized over the period in which they are reflected in customer rates. In the event that recovery of Idaho Power's costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power's operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a significant financial impact.

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes (including PURPA power purchases), and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments consist of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during each of the years ended December 31, 2012, 2011, and 2010.

Effective Date	$ Change (millions)	Notes
June 1, 2012	$ 43.0	The PCA rate increase was offset by $27.1 million to be shared with customers pursuant to the revenue sharing order described below, resulting in a net rate increase of $15.9 million for these orders.
June 1, 2011	$ (40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.
June 1, 2010	$ (146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below. 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 each of the three years ended December 31, 2012, 2011, and 2010 are summarized in the table that follows.

Year and Mechanism	APCU or PCAM Adjustment
2012 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2012 APCU	A rate increase of $1.8 million annually took effect June 1, 2012.
2011 PCAM	Actual net power supply costs were below the deadband, which would have resulted in a $1.5 million deferral. However, Oregon-jurisdiction earnings were below the ROE threshold described above, resulting in no deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
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 Settlement: On June 1, 2011, Idaho Power filed a general rate case with the IPUC requesting approximately $82.6 million in additional Idaho jurisdiction annual revenues through base rates. On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case, and on December 30, 2011 the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 2011 order provided for a 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity and did not impose a moratorium on Idaho Power's filing a general rate case at a future date.

In addition to a base rate increase, the settlement stipulation addressed Idaho Power's calculation of the load change adjustment rate (LCAR) to be applied in Idaho Power's PCA mechanism. The LCAR is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The LCAR adjusts power supply cost recovery within the Idaho-jurisdiction PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provided for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

January 2010 Idaho Settlement Agreement: In January 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power's customers, the IPUC Staff, and other interested parties. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

In April 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. In May 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Because Idaho Power's actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdiction earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

December 2011 Idaho Settlement Agreement: The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power extending, with modifications, some of the provisions of the January 2010 settlement agreement. The settlement stipulation provided that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA adjustment; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

The December 2011 settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the December 2011 settlement stipulation further provided that Idaho Power would allocate to customers as a reduction to the pension regulatory asset 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE.

Revenue Sharing Under January 2010 and December 2011 Idaho Settlement Agreements: On May 31, 2012, the IPUC issued an order approving Idaho Power's request to share revenues under the January 2010 and December 2011 settlement agreements. Idaho Power recorded in 2011 a $27.1 million reduction to revenue for amounts to be refunded to customers and a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers (reducing Idaho customers' future obligation). The refund is being applied to the PCA rates in effect from June 1, 2012 to May 31, 2013.

Idaho Power's 2012 Idaho ROE exceeded 10.5 percent, triggering the sharing mechanism of the December 2011 settlement stipulation. For 2012, Idaho Power recorded a $7.2 million provision against current revenues, to be refunded to customers through a future rate reduction, and an additional $14.6 million of pension expense, to benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future.

Fixed Cost Adjustment: The fixed cost adjustment (FCA) began as a pilot program for Idaho Power's Idaho residential and small general service customers, with a term from 2007 through 2009. The FCA is designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. In April 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011, and in March 2012 the IPUC issued an order approving the FCA as a permanent program. The order also maintained the existing cap on the FCA of no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The IPUC noted in its order, however, that the FCA does not isolate or identify changes in cost recovery associated solely with Idaho Power's energy efficiency programs, and instead responds to all changes in load, and directed Idaho Power to file with the IPUC a proposal to adjust the FCA. On September 28, 2012, Idaho Power submitted a compliance filing and motion to the IPUC requesting that the IPUC approve the FCA methodology used during the pilot program, without change, or an alternative methodology proposed by Idaho Power. On January 31, 2013, the IPUC issued an order stating that the FCA will continue unchanged, but that the IPUC will continue to monitor the FCA results annually.

On May 8, 2012, the IPUC issued an order authorizing Idaho Power to increase its annual FCA collection to $10.3 million for the period from June 1, 2012 to May 31, 2013. The following table summarizes FCA rate adjustments since inception:

FCA Year	Period rates in effect	Annual Amount (in millions)	
2011	June 1, 2012-May 31, 2013	$	10.3
2010	June 1, 2011-May 31, 2012	$	9.3
2009	June 1, 2010-May 31, 2011	$	6.3
2008	June 1, 2009-May 31, 2010	$	2.7

As of December 31, 2012, Idaho Power had a $13.4 million regulatory asset associated with the FCA.

Cost Recovery for Langley Gulch Power Plant: On March 2, 2012, Idaho Power filed an application with the IPUC requesting an increase in annual Idaho-jurisdiction base rates of $59.9 million for recovery of Idaho Power's investment and associated costs for the Langley Gulch power plant, which became commercially available on June 29, 2012. Idaho Power's application stated that its estimated investment in the plant through June 2012 was approximately $398 million. After the impact of depreciation, deferred income taxes, amounts currently included in rates, and an Idaho-jurisdictional cost allocation, Idaho Power's application requested a $336.7 million increase in Idaho-jurisdiction rate base. Idaho Power's requested base rate increase was based on an overall rate of return of 7.86 percent, as authorized by a prior IPUC order. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Inclusion of the Langley Gulch power plant in Idaho Power's power supply portfolio also resulted in a change in Idaho Power's power supply cost assumptions. Accordingly, in the Langley Gulch order the IPUC also updated Idaho Power's LCAR to $17.64 per MWh, effective July 1, 2012.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2012, Idaho Power's deferral balance associated with the Idaho-jurisdiction was $62.9 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. Idaho Power has made substantial contributions to its defined benefit pension plan in recent years. The single largest contribution occurred in September 2010, when Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount. The amount contributed over the minimum required contribution was intended to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power's application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan and during 2012 contributed $44.3 million.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. In the 2012 PCA filing, $14.5 million of certain demand response program costs were shifted from the rider mechanism to the PCA mechanism, as these costs are closely related to and directly impact the other power supply costs collected through the PCA.

On March 15, 2012, Idaho Power filed an application with the IPUC requesting an order designating Idaho Power's 2011 demand-side management expenditures of $42.6 million as prudently incurred. On October 22, 2012 and December 11, 2012, the IPUC issued orders approving as prudently incurred $42.5 million of demand-side management expenditures, and deferring a portion of Idaho Power's additional requested amount for further review. Of Idaho Power's 2011 demand-side management expenditures, approximately $36 million were funded through a rider mechanism on customer bills and approximately $7 million were recorded as a regulatory asset. As of December 31, 2012, the Idaho energy efficiency rider balance was a regulatory liability of $4.1 million. Idaho Power's previous application filed in March 2011, which was approved by the IPUC in August 2011, designated Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. The IPUC also issued an order in November 2010 designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred and approved for ratemaking purposes.

On October 31, 2012, Idaho Power filed an application with the IPUC requesting authorization to begin amortization and collection of the 2011 portion of the regulatory asset associated with its custom efficiency program (a demand-side resources program) over a four-year period, equal to approximately $2.9 million per year, including a carrying charge. A decision of the IPUC is pending.

The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Cost Recovery for Cessation of Boardman Coal-Fired Operations: In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The plan results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. In response to an application filed by Idaho Power, on February 15, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early plant shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On May 17, 2012, the IPUC issued an order approving a $1.5 million annual increase in Idaho-jurisdiction base rates, with new rates effective June 1, 2012. As of December 31, 2012, Idaho Power's net book value in the Boardman plant was $23.1 million.

Idaho Depreciation Rate Filings: Idaho Power's advanced metering infrastructure (AMI) project provides the means to automatically retrieve and store energy consumption information, eliminating manual meter reading expense. Commencing June 1, 2009, the IPUC approved a rate increase, coincident with a related increase in depreciation expense, allowing Idaho Power to recover the three-year accelerated depreciation of the existing non-AMI metering equipment and to begin earning a return on its AMI investment. On April 27, 2012, the IPUC approved Idaho Power's February 15, 2012 application requesting approval of a $10.6 million decrease in rates for specified customer classes, effective June 1, 2012, as a result of the removal of accelerated depreciation expense associated with non-AMI metering equipment.

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated service life estimates and net salvage percentages for all plant assets, and adjust Idaho-jurisdiction base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdiction base rates. On May 31, 2012, the IPUC issued an order approving a settlement stipulation agreed to by Idaho Power, the IPUC Staff, and a large industrial customer of Idaho Power, which provided for a $1.3 million annual decrease in Idaho-jurisdiction base rates, effective June 1, 2012.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues and an authorized rate of return on equity of 10.5 percent, with an Oregon retail rate base of approximately $121.9 million. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolved all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The OPUC approved the settlement stipulation on February 23, 2012, which provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger plant.

Cost Recovery for Langley Gulch Power Plant: On March 9, 2012, Idaho Power filed an application with the OPUC requesting an annual increase in Oregon jurisdiction revenues of $3.0 million for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates effective October 1, 2012.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its open access transmission tariff (OATT), which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per kW-year)[1]	
October 1, 2012 to September 30, 2013	$	21.32
October 1, 2011 to September 30, 2012	$	19.79
October 1, 2010 to September 30, 2011	$	19.60
October 1, 2009 to September 30, 2010	$	15.83

(1) 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.

Idaho Power's most recent OATT filing was based on a net annual transmission revenue requirement of $108.4 million.

4. LONG-TERM DEBT

The following table summarizes IDACORP's and Idaho Power's long-term debt at December 31 (in thousands of dollars):

	2012	2011
First mortgage bonds:		
4.75% Series due 2012	$ —	$ 100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
2.95% Series Due 2022	75,000	—
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	—
Total first mortgage bonds	1,345,000	1,295,000
Pollution control revenue bonds:		
5.15% Series due 2024[1]	49,800	49,800
5.25% Series due 2026[1]	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	5,318	6,382
Unamortized premium/discount - net	(2,967)	(3,113)
Total IDACORP and Idaho Power outstanding debt[2]	1,537,696	1,488,614
Current maturities of long-term debt	(71,064)	(101,064)
Total long-term debt	$ 1,466,632	$ 1,387,550

[1] Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2012 to $1.511 billion.

[2] At December 31, 2012 and 2011, the overall effective cost of Idaho Power's outstanding debt was 5.44 percent and 5.43 percent, respectively.

At December 31, 2012, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2013	2014	2015	2016	2017	Thereafter
$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,064	$ 1,465,343

IDACORP Long-Term Financing

As of December 31, 2012, IDACORP had approximately $539 million remaining on a shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) that can be used for the issuance of debt securities or IDACORP common stock. Common stock is discussed further in Note 6.

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. In August 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, medium-term notes, Series I maturing in August 2020, and $100 million of 4.85% first mortgage bonds, medium-term notes, Series I maturing in August 2040. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022, and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042. The first mortgage bonds were issued under Idaho Power's shelf registration statement. As a result of these issuances, as of December 31, 2012, $150 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 sale of first mortgage bonds, medium-term notes to effect the early redemption in full of its $100 million of 4.75% first mortgage bonds, medium-term notes due November 2012.

Mortgage: As of December 31, 2012, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

The Mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the Mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of Idaho Power are subject to easements, leases, contracts, covenants, workmen's compensation awards, and similar encumbrances and minor defects and clouds common to properties. The Mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities, or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The Mortgage creates a lien on the interest of Idaho Power in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger, or sale of all or substantially all of the assets of Idaho Power. The Mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

5. NOTES PAYABLE

Credit Facilities

IDACORP and Idaho Power have $125 million and $300 million credit facilities, respectively, which may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. 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.

IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

The IDACORP and Idaho Power credit facilities have similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities. While the credit facilities provide for an original maturity date of October 26, 2016, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On October 12, 2012, IDACORP and Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity dates under both agreements to October 26, 2017.

At December 31, 2012, no amounts were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2012, Idaho Power had regulatory authority to incur up to $450 million principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of IDACORP's and Idaho Power's short-term borrowings were as follows at December 31:

	IDACORP		Idaho Power		Total	
	2012	2011	2012	2011	2012	2011
Commercial paper balances:						
At the end of year	$ 69,700	$ 54,200	$ —	$ —	$ 69,700	$ 54,200
Average during the year	$ 57,947	$ 65,574	$ 3,578	$ —	$ 61,525	$ 65,574
Weighted-average interest rate						
At the end of the year	0.50%	0.47%	—%	—%	0.50%	0.47%

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes common stock transactions during the last three years and shares reserved at December 31, 2012:

	Shares issued			Shares reserved
	2012	2011	2010	December 31, 2012
Balance at beginning of year	49,964,172	49,419,452	47,925,882	
Continuous equity program	—	—	973,585	3,000,000
Dividend reinvestment and stock purchase plan	62,084	119,999	144,655	2,576,723
Employee savings plan	49,296	91,277	105,375	3,567,954
Long-term incentive and compensation plan	82,934	333,444	256,662	1,618,260
Restricted stock plan	—	—	13,293	256,154
Balance at end of year	50,158,486	49,964,172	49,419,452	

IDACORP enters into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. IDACORP's current sales agency agreement is with BNY Mellon Capital Markets, LLC. As of December 31, 2012, there were approximately 3 million shares remaining available to be sold under the current sales agency agreement. No shares were issued under the sales agency agreement in 2011 or 2012. IDACORP sold 973,585 shares in 2010 at an average price of $35.47.

Idaho Power Common Stock

In 2012, 2011, and 2010, IDACORP contributed $7.5 million, $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 IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios 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 and IDACORP's ability to pay dividends on its common stock are 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, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $889 million and $794 million, respectively, at December 31, 2012. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2012, IDACORP and Idaho Power were in compliance with all facility covenants.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2012, Idaho Power's common equity capital was 51 percent of its total adjusted capital. Further, Idaho Power must obtain the approval of the OPUC before it may directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. As of the date of this report, Idaho Power has no shares of preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act but could be interpreted to limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

7. STOCK-BASED COMPENSATION

IDACORP has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2012, the maximum number of shares available under the LTICP and RSP were 1,371,305 and 15,796, respectively.

Stock Awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the closing market price of common stock on the grant date and is charged to compensation expense over the vesting period, based on the number of shares expected to vest.

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. Based on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The performance awards are based on two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of these awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of these awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock and performance share activity is presented below. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	IDACORP			Idaho Power		
	Number of Shares		Weighted-Average Grant Date Fair Value	Number of Shares		Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2012	339,938	$	26.40	337,183	$	26.40
Shares granted	123,048		37.59	120,549		37.56
Shares forfeited	(2,098)		35.59	(2,098)		35.59
Shares vested	(140,150)		22.42	(138,923)		22.42
Nonvested shares at December 31, 2012	320,738	$	32.36	316,711	$	32.32

The total fair value of shares vested during the years ended December 31, 2012, 2011, and 2010 was $4.9 million, $4.1 million, and $3.3 million, respectively. At December 31, 2012, IDACORP had $4.8 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4.7 million. These costs are expected to be recognized over a weighted-average period of 1.71 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2012, a total of 14,820 shares were awarded to directors at a grant date fair value of $40.48 per share. Directors elected to defer receipt of 7,410 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2012, all compensation costs have been recognized. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

IDACORP's and Idaho Power's stock option transactions are summarized below. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	Number of Shares		Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)		Aggregate Intrinsic Value (000s)
IDACORP						
Outstanding at December 31, 2011	27,806	$	32.29	1.75	$	281
Exercised	(8,600)		33.62			
Expired	(4,000)		39.50			
Outstanding at December 31, 2012	15,206	$	29.64	1.45	$	208
Vested and exercisable at December 31, 2012	15,206	$	29.64	1.45	$	208
Idaho Power						
Outstanding at December 31, 2011	9,456	$	33.67	1.58	$	83
Exercised	(1,500)		28.45			
Expired	(4,000)		39.50			
Outstanding at December 31, 2012	3,956	$	29.75	2.05	$	54
Vested and exercisable at December 31, 2012	3,956	$	29.75	2.05	$	54

The following table presents information about options vested and exercised (in thousands of dollars):

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
Fair value of options vested	$ —	$ —	$ 110	$ —	$ —	$ 96
Intrinsic value of options exercised	74	884	1,491	36	535	1,475
Cash received from exercises	289	9,423	5,475	77	3,838	5,394
Tax benefits realized from exercises	29	345	583	14	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):

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
Compensation cost	$ 4,696	$ 4,207	$ 3,706	$ 4,577	$ 4,082	$ 3,489
Income tax benefit	1,836	1,645	1,449	1,789	1,596	1,364

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share (EPS) for the years ended December 31, 2012, 2011, and 2010 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2012	2011	2010
Numerator:			
Net income attributable to IDACORP, Inc.	$ 168,761	$ 166,693	$ 142,798
Denominator:			
Weighted-average common shares outstanding - basic	49,930	49,457	48,193
Effect of dilutive securities:			
Options	4	16	32
Restricted Stock	76	85	115
Weighted-average common shares outstanding - diluted	50,010	49,558	48,340
Basic earnings per share	$ 3.38	$ 3.37	$ 2.96
Diluted earnings per share	$ 3.37	$ 3.36	$ 2.95

The diluted EPS computation excludes 137,880 and 332,182 options for the years ended December 31, 2011 and 2010, respectively, because the options' exercise prices were greater than the average market price of the common stock during that year. No such options were required to be excluded from the December 31, 2012 calculation. In total, 15,206 options were outstanding at December 31, 2012, with expiration dates between 2014 and 2015.

9. COMMITMENTS

Purchase Obligations

At December 31, 2012, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2013	2014	2015	2016	2017	Thereafter
Cogeneration and power production	$ 170,939	$ 182,123	$ 187,151	$ 189,880	$ 188,734	$2,938,582
Power and transmission rights	6,408	5,035	4,320	3,992	2,840	4,743
Fuel	73,627	63,236	56,942	9,418	9,317	94,849

As of December 31, 2012, Idaho Power had 779 MW nameplate capacity of PURPA-related projects on-line, with an additional 52 MW nameplate capacity of projects projected to be on-line by the end of 2014. The power purchase contracts for these projects have terms ranging from one to 35 years. During 2012, Idaho Power purchased 1,961,208 megawatt-hours (MWh) from these projects at a cost of $118 million, resulting in a blended price of $59.98 per MWh. Idaho Power purchased 1,495,108 MWh at a cost of $90 million in 2011, and 910,429 MWh at a cost of $55 million in 2010.

In addition, Idaho Power has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousands of dollars):

	2013	2014	2015	2016	2017	Thereafter
Operating leases	$ 1,888	$ 2,116	$ 2,123	$ 1,243	$ 955	$ 15,741
Equipment, maintenance, and service agreements	35,233	9,483	5,464	4,277	4,484	21,176
FERC and other industry-related fees	13,789	11,066	11,066	7,472	7,472	37,361

IDACORP's expense for operating leases was approximately $6.1 million in 2012, $5.3 million in 2011, and $3.4 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 $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

IDACORP and Idaho Power enter 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. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2012, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish 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. IDACORP and Idaho Power monitor 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, IDACORP and Idaho Power do 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, IDACORP's and Idaho Power's accruals for loss contingencies are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and 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 IDACORP and Idaho Power are able to estimate the loss may change, and the estimates themselves may change. For matters that affect Idaho Power's operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending petitions and predict that these matters will not have a material adverse effect on IDACORP's or Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC characterized these ripple claims as "speculative." However, the FERC refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve a settlement that provided for waivers of all claims in those proceedings, despite only limited objections from two market participants. Idaho Power and IESCo have petitioned for review of the FERC's decision. Based on its evaluation of the merits of such claims and the inability to estimate any potential exposure should the claims ultimately have merit, Idaho Power and IESCo have no remaining amount accrued for financial statement purposes relating to the western energy proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses. Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970s and early 1980s these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation in March 1988.

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power also continues its active participation in the SRBA in seeking to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, as of the date of this report Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Proceedings

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the companies believe that resolution of those matters will not have a material adverse effect on their consolidated financial statements. Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

11. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. IDACORP also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power's pension plans include a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power's funding policy for its pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2012, 2011, and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

The following table summarizes the changes in benefit obligations and plan assets of these plans (in thousands of dollars):

	Pension Plan		SMSP	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation at January 1	$ 655,439	$ 569,934	$ 65,043	$ 59,126
Service cost	25,571	20,478	2,151	1,950
Interest cost	31,489	30,322	3,218	3,094
Actuarial loss	77,328	55,535	13,335	4,251
Benefits paid	(22,135)	(20,830)	(3,232)	(3,378)
Benefit obligation at December 31	767,692	655,439	80,515	65,043
Change in plan assets:				
Fair value at January 1	390,081	397,003	—	—
Actual return on plan assets	48,616	(4,592)	—	—
Employer contributions	44,300	18,500	—	—
Benefits paid	(22,135)	(20,830)	—	—
Fair value at December 31	460,862	390,081	—	—
Funded status at end of year	$ (306,830)	$ (265,358)	$ (80,515)	$ (65,043)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,651)	$ (3,496)
Noncurrent liabilities	(306,830)	(265,358)	(76,864)	(61,547)
Net amount recognized	$ (306,830)	$ (265,358)	$ (80,515)	$ (65,043)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 291,966	$ 245,632	$ 33,605	$ 21,799
Prior service cost	989	1,335	1,289	1,502
Subtotal	292,955	246,967	34,894	23,301
Less amount recorded as regulatory asset	(292,955)	(246,967)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,894	$ 23,301
Accumulated benefit obligation	$ 640,330	$ 549,503	$ 72,288	$ 59,836

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. These investments totaled approximately $50.4 million and $41.2 million at December 31, 2012 and 2011, respectively, and are reflected in Investments and Company-owned life insurance on the consolidated balance sheets.

The table that follows shows the components of net periodic benefit cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan			SMSP		
	2012	2011	2010	2012	2011	2010
Service cost	$ 25,571	$ 20,478	$ 17,671	$ 2,151	$ 1,950	$ 1,541
Interest cost	31,489	30,322	29,119	3,218	3,094	3,004
Expected return on assets	(31,737)	(32,322)	(26,463)	—	—	—
Amortization of net loss	14,114	8,673	7,675	1,530	1,293	931
Amortization of prior service cost	347	519	650	212	242	233
Net periodic pension cost	39,784	27,670	28,652	7,111	6,579	5,709
Adjustments due to the effects of regulation[(1)]	(5,860)	6,662	(24,104)	—	—	—
Net periodic benefit cost recognized for financial reporting	$ 33,924	$ 34,332	$ 4,548	$ 7,111	$ 6,579	$ 5,709

[(1)] Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's revenue sharing mechanism approved by the IPUC, which resulted in additional Idaho pension expense of $14.6 million and $20.3 million in 2012 and 2011, respectively.

The following table shows the components of other comprehensive income for the plans (in thousands of dollars):

	Pension Plan			SMSP		
	2012	2011	2010	2012	2011	2010
Actuarial loss during the year	$ (60,448)	$ (92,449)	$ (19,334)	$ (13,335)	$ (4,251)	$ (5,187)
Reclassification adjustments for:						
Amortization of net loss	14,114	8,673	7,675	1,530	1,293	931
Amortization of prior service cost	347	519	650	212	242	233
Adjustment for deferred tax effects	17,979	32,193	4,660	4,532	1,062	1,573
Adjustment due to the effects of regulation	28,008	51,064	6,349	—	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ —	$ (7,061)	$ (1,654)	$ (2,450)

In 2013, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $20.4 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2012, relating to the pension plan and SMSP. This amount consists of $17.0 million of amortization of net loss and $0.4 million of amortization of prior service cost for the pension plan, and $2.8 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2013	2014	2015	2016	2017	2018-2022
Pension Plan	$ 23,882	$ 25,591	$ 27,490	$ 29,729	$ 32,179	$ 199,630
SMSP	3,721	3,948	4,130	4,129	4,326	23,932

As of December 31, 2012, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2013. IDACORP and Idaho Power may elect to make discretionary contributions above the minimum funding requirements or at times earlier than the required dates.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

The following table summarizes the changes in benefit obligation and plan assets (in thousands of dollars):

	2012	2011
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 66,669	$ 68,048
Service cost	1,292	1,323
Interest cost	3,135	3,434
Actuarial loss (gain)	3,180	(2,850)
Benefits paid[(1)]	(1,729)	(2,968)
Plan amendments	—	(318)
Benefit obligation at December 31	72,547	66,669
Change in plan assets:		
Fair value of plan assets at January 1	31,901	33,176
Actual return on plan assets	3,346	1,065
Employer contributions[(1)]	(131)	628
Benefits paid[(1)]	(1,729)	(2,968)
Fair value of plan assets at December 31	33,387	31,901
Funded status at end of year (included in noncurrent liabilities)	$ (39,160)	$ (34,768)

[(1)] Contributions and benefits paid are each net of $3,268 and $3,405 of plan participant contributions, and $430 and $444 of Medicare Part D subsidy receipts for 2012 and 2011, respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2012	2011
Net loss	$ 15,796	$ 14,112
Prior service cost (credit)	99	(323)
Transition obligation	—	2,040
Subtotal	15,895	15,829
Less amount recognized in regulatory assets	(15,895)	(15,536)
Less amount included in deferred tax assets	—	(293)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

The net periodic postretirement benefit cost was as follows (in thousands of dollars):

	2012	2011	2010
Service cost	$ 1,292	$ 1,323	$ 1,276
Interest cost	3,135	3,434	3,578
Expected return on plan assets	(2,234)	(2,641)	(2,503)
Amortization of net loss	384	577	562
Amortization of prior service cost	(422)	(421)	(482)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Net periodic postretirement benefit cost	$ 4,195	$ 4,312	$ 4,471

The following table shows the components of other comprehensive income for the plan (in thousands of dollars):

	2012	2011	2010
Actuarial (loss) gain during the year	$ (2,068)	$ 1,274	$ (2,413)
Prior service cost arising during the year	—	318	(629)
Reclassification adjustments for:			
Amortization of net loss	384	577	562
Amortization of prior service cost	(422)	(421)	(482)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Adjustment for deferred tax effects	(153)	(1,659)	18
Adjustment due to the effects of regulation	219	(2,129)	904
Other comprehensive income related to postretirement benefit plans	$ —	$ —	$ —

In 2013, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $0.6 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2012, relating to the postretirement benefit plan. This amount consists of $0.7 million of amortization of net loss and $(0.1) million of amortization of prior service cost.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2013	2014	2015	2016	2017	2018-2022
Expected benefit payments	$ 4,010	$ 4,180	$ 4,320	$ 4,430	$ 4,530	$ 23,420
Expected Medicare Part D subsidy receipts	480	520	560	620	670	4,360

Plan Assumptions

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all Idaho Power-sponsored pension and postretirement benefits plans:

	Pension Plan		SMSP		Postretirement Benefits	
	2012	2011	2012	2011	2012	2011
Discount rate	4.20%	4.90%	4.15%	5.10%	4.20%	5.05%
Rate of compensation increase[(1)]	4.35%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.5%	7.0%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2012	12/31/2011	12/31/2012	12/31/2011	12/31/2012	12/31/2011

[(1)] The 2012 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Pension Plan			SMSP			Postretirement Benefits		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
Discount rate	4.90%	5.40%	5.90%	5.10%	5.40%	5.90%	5.05%	5.40%	5.90%
Expected long-term rate of return on assets	7.75%	8.25%	8.25%	—	—	—	7.25%	8.25%	8.25%
Rate of compensation increase	4.35%	4.50%	4.50%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	6.5%	7.0%	7.5%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.5 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2012 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 343	$ (255)
Effect on accumulated postretirement benefit obligation	3,482	(2,708)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2012 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation December 31, 2012
Debt securities	24%	24%
Equity securities	54%	55%
Real estate	6%	6%
Other plan assets	16%	15%
Total	100%	100%

Assets are rebalanced as necessary to keep the portfolio close to target allocations.

The plan's principal investment objective is to maximize total return (defined as the sum of realized interest and dividend income and realized and unrealized gain or loss in market price) consistent with prudent parameters of risk and the liability profile of the portfolio. Emphasis is placed on preservation and growth of capital along with adequacy of cash flow sufficient to fund current and future payments to pensioners.

The three major goals in Idaho Power's asset allocation process are to:

- determine if the investments have the potential to earn the rate of return assumed in the actuarial liability calculations;
- match the cash flow needs of the plan. Idaho Power sets bond allocations sufficient to cover at least five years of benefit payments and cash allocations sufficient to cover the current year benefit payments. Idaho Power then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan; and
- maintain a prudent risk profile consistent with ERISA fiduciary standards.

Allowable plan investments include stocks and stock funds, investment-grade bonds and bond funds, core real estate funds, private equity funds, and cash and cash equivalents. With the exception of real estate holdings and private equity, investments must be readily marketable so that an entire holding can be disposed of quickly with only a minor effect upon market price.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

Idaho Power's asset modeling process also utilizes historical market returns to measure the portfolio's exposure to a "worst-case" market scenario, to determine how much performance could vary from the expected "average" performance over various time periods. This "worst-case" modeling, in addition to cash flow matching and diversification by asset class and investment style, provides the basis for managing the risk associated with investing portfolio assets.

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 16. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2012				
Pension assets:				
Cash and cash equivalents	$ 7,628	$ —	$ —	$ 7,628
Short-term bonds	—	12,373	—	12,373
Long-term bonds	—	96,671	—	96,671
Equity Securities: Large-Cap	57,526	—	—	57,526
Equity Securities: Mid-Cap	19,944	16,780	—	36,724
Equity Securities: Small-Cap	36,409	—	—	36,409
Equity Securities: Micro-Cap	19,923	—	—	19,923
Equity Securities: International	19,461	59,142	—	78,603
Equity Securities: Emerging Markets	3,101	21,370	—	24,471
Equity Securities: Market Neutral	7,675	—	—	7,675
Real estate	—	—	27,874	27,874
Private market investments	—	—	30,507	30,507
Commodities funds	1,420	23,058	—	24,478
Total pension assets	$ 173,087	$ 229,394	$ 58,381	$ 460,862
Postretirement assets[1]	$ 325	$ 33,062	$ —	$ 33,387

[1] The postretirement benefits assets are primarily life insurance contracts.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2011				
Pension assets:				
Cash and cash equivalents	$ 6,141	$ —	$ —	$ 6,141
Short-term bonds	—	23,443	—	23,443
Long-term bonds	—	74,658	—	74,658
Equity Securities: Large-Cap	51,780	—	—	51,780
Equity Securities: Mid-Cap	17,961	14,002	—	31,963
Equity Securities: Small-Cap	31,825	—	—	31,825
Equity Securities: Micro-Cap	16,087	—	—	16,087
Equity Securities: International	30,444	32,118	—	62,562
Equity Securities: Emerging Markets	1,745	15,112	—	16,857
Real estate	—	—	25,119	25,119
Private market investments	—	—	27,786	27,786
Commodities funds	2,929	18,931	—	21,860
Total pension assets	$ 158,912	$ 178,264	$ 52,905	$ 390,081
Postretirement assets[1]	$ —	$ 31,901	$ —	$ 31,901

[1] The postretirement benefits assets are primarily life insurance contracts.

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3):

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2011	$ 29,932	$ 22,069	$ 52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	27,786	25,119	52,905
Realized gains	95	742	837
Unrealized gains	1,387	1,271	2,658
Purchases	1,779	742	2,521
Sales	(540)	—	(540)
Ending balance - December 31, 2012	$ 30,507	$ 27,874	$ 58,381

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs:

Level 2 Bonds, Equity Securities, and Level 2 Commodities: These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 3 Real Estate: Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

The fair value of the Level 3 assets is determined based on pricing provided or reviewed by third-party vendors to our investment managers. While the input amounts used by the pricing vendors in determining fair value are not provided, and therefore unavailable for Idaho Power's review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar assets classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2012 and 2011.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and which covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $7 million, $6 million, and $5 million in 2012, 2011, and 2010, respectively.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and Idaho Power's consolidated balance sheets at December 31, 2012 and 2011 are $2.6 million and $3.8 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2012 and 2011 (in thousands of dollars):

	2012		2011	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,217,334	2.36%	$ 1,832,287	2.22%
Transmission	931,403	2.02%	871,784	2.06%
Distribution	1,411,740	2.89%	1,434,925	3.12%
General and Other	355,295	6.47%	327,877	7.32%
Total in service	4,915,772	2.75%	4,466,873	2.83%
Accumulated provision for depreciation	(1,703,159)		(1,677,609)	
In service - net	$ 3,212,613		$ 2,789,264	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses are included in the Consolidated

Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2012 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW [(1)]
Jim Bridger Units 1-4	Rock Springs, WY	$ 542,894	$ 16,528	$ 280,875	33	771
Boardman	Boardman, OR	79,031	1,355	55,940	10	64
Valmy Units 1 and 2	Winnemucca, NV	353,541	10,163	198,190	50	284

(1) Idaho Power's share of nameplate capacity.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $75 million, $65 million, and $76 million in 2012, 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, $9 million, and $8 million in 2012, 2011, and 2010, respectively.

See Note 1 for a discussion of the property of IDACORP's consolidated VIE.

13. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, Idaho Power records regulatory assets or liabilities instead of accretion, depreciation, and gains or losses, as approved by the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2012, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $1.4 million in the recorded AROs. The primary cause of the increase in the AROs in 2012 is an increased ARO for the Valmy generating facility evaporation pond as determined by a revised evaporation pond decommissioning study.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, and jointly owned coal-fired generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the costs recorded as regulatory liabilities on IDACORP's and Idaho Power's Consolidated Balance Sheets as of December 31, 2012 and 2011.

The following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	2012	2011
Balance at beginning of year	$ 21,367	$ 16,952
Accretion expense	984	936
Revisions in estimated cash flows	1,416	3,930
Liability settled	(785)	(451)
Balance at end of year	$ 22,982	$ 21,367

14. INVESTMENTS

The table below summarizes IDACORP's and Idaho Power's investments as of December 31 (in thousands of dollars).

	2012	2011
Idaho Power investments:		
Equity method investment	$ 93,650	$ 102,158
Available-for-sale equity securities	31,913	22,205
Executive deferred compensation plan	2,478	3,439
Other investments	2	2
Total Idaho Power investments	128,043	127,804
Investments in affordable housing	50,740	62,556
Equity method investments	11,596	10,782
Total IDACORP investments	$ 190,379	$ 201,142

Equity Method Investments

Idaho Power, through its subsidiary IERCo, is a 33 percent owner of BCC. Ida-West, through separate subsidiaries, owns 50 percent of three electric generation projects that are accounted for using the equity method: South Forks Joint Venture; Hazelton/Wilson Joint Venture, and Snow Mountain Hydro LLC. IFS invests in affordable housing developments. All projects are reviewed periodically for impairment. The table below presents IDACORP's and Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars).

	2012	2011	2010
Bridger Coal Company (Idaho Power)	$ 9,412	$ 9,018	$ 11,281
Ida-West projects	2,215	2,858	2,579
IFS affordable housing projects (excluding tax credits)	(11,955)	(11,078)	(10,852)
Total	$ (328)	$ 798	$ 3,008

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

The table below summarizes investments in equity securities by IDACORP and Idaho Power as of December 31, 2012 and December 31, 2011 (in thousands of dollars).

	December 31, 2012			December 31, 2011		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 6,792	$ —	$ 31,913	$ 4,220	$ 1	$ 22,205

At the end of each reporting period, IDACORP and Idaho Power analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2012, there were no securities in an unrealized loss position. At December 31, 2011, one security was in an immaterial unrealized loss position. No other-than-temporary impairment was recognized for this security due to the limited severity and duration of the unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2012, 2011, or 2010.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. The objective of Idaho Power's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

All commodity-related derivative instruments not meeting the normal purchases and normal sales exception to derivative accounting are recorded at fair value on the balance sheet. Because of Idaho Power's PCA mechanisms, unrealized gains and losses associated with the changes in fair value of these derivative instruments are recorded as regulatory assets or liabilities. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities, Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception.

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges under derivative accounting guidance. Idaho Power offsets fair value amounts recognized on its balance sheet related to derivative instruments executed with the same counterparty under the same master netting agreement.

Derivative Instruments Summary

The tables below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets at December 31, 2012 and 2011 (in thousands of dollars).

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
December 31, 2012				
Current:				
Financial swaps	Other current assets	$ 5,122	Other current assets	$ 978
Financial swaps	Other current liabilities	320	Other current liabilities	1,372
Forward contracts	Other current assets	155	Other current assets	4
Forward contracts			Other current liabilities	2
Long-term:				
Financial swaps	Other assets	96		
Forward contracts	Other assets	189		
Total		$ 5,882		$ 2,356
December 31, 2011				
Current:				
Financial swaps	Other current assets	$ 4,361	Other current assets	$ 1,036
Financial swaps	Other current liabilities	1,526	Other current liabilities	4,755
Forward contracts	Other current assets	70	Other current liabilities	1,370
Long-term:				
Financial swaps	Other assets	359	Other liabilities	108
Total		$ 6,316		$ 7,269

The table below presents the gains and losses on derivatives not designated as hedging instruments for the year ended December 31, 2012 and 2011 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[1] 2012	2011
Financial swaps	Off-system sales	$ 15,104	$ 9,594
Financial swaps	Purchased power	(6,280)	(7,124)
Financial swaps	Fuel expense	(6,359)	501
Financial swaps	Other operations and maintenance	(302)	425
Forward contracts	Fuel expense	(1,755)	—

[1] Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 16 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Idaho Power had volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2012 and 2011 set forth in the table below.

Commodity	Units	December 31, 2012	2011
Electricity purchases	MWh	404,990	225,600
Electricity sales	MWh	1,373,525	1,298,420
Natural gas purchases	MMBtu	13,476,660	7,928,311
Natural gas sales	MMBtu	3,932,889	352,129
Diesel purchases	Gallons	833,921	1,273,997

Credit Risk

At December 31, 2012, Idaho Power did not have material credit exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are under Western Systems Power Pool agreements, physical gas contracts are under North American Energy Standards Board contracts, and financial transactions are under International Swaps and Derivatives Association, Inc. contracts. These contracts all contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2012, was $2.4 million. Idaho Power posted no collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, Idaho Power would have been required to post $5.9 million of cash collateral to its counterparties.

16. FAIR VALUE MEASUREMENTS

IDACORP and Idaho Power have categorized their financial instruments into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument.

Financial assets and liabilities recorded on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

- Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that IDACORP and 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.

  IDACORP and 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 IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2012 and 2011 (in thousands of dollars). IDACORP's and Idaho Power's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels for the years presented.

	December 31, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivatives	$ 2,201	$ 1,674	$ —	$ 3,875	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	2,478	—	—	2,478	3,439	—	—	3,439
Available-for-sale securities: Equity securities	31,913	—	—	31,913	22,205	—	—	22,205
Liabilities:								
Derivatives	$ —	$ 1,055	$ —	$ 1,055	$ 405	$ 4,302	$ —	$ 4,707

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2012 and 2011, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable and long-term debt are based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

	December 31, 2012		December 31, 2011	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable [1]	$ 3,097	$ 3,097	$ 3,097	$ 3,097
Liabilities:				
Long-term debt [1]	1,537,696	1,819,213	1,491,727	1,737,912
Idaho Power				
Liabilities:				
Long-term debt [1]	$ 1,537,696	$ 1,819,213	$ 1,491,727	$ 1,737,912

[1] Notes receivable and long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16.

17. SEGMENT INFORMATION

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of Idaho Power. Idaho Power's regulated operations include the generation, transmission, distribution, purchase, and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of Idaho Power that is also subject to regulation and is a thirty-three percent owner of BCC, an unconsolidated joint venture.

IDACORP's other operating segments are below the quantitative and qualitative thresholds for reportable segments and are included in the "All Other" category in the table below. This category is comprised of IFS's investments in affordable housing developments and historic rehabilitation projects, Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of IESCo, the successor to which wound down its energy marketing operations in 2003, and IDACORP's holding company expenses.

The tables below summarize the segment information for IDACORP's utility operations and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars).

	Utility Operations	All Other	Eliminations	Consolidated Total
2012				
Revenues	$ 1,076,725	$ 3,937	$ —	$ 1,080,662
Operating income	242,179	423	—	242,602
Other income	23,996	368	—	24,364
Interest income	1,980	380	(81)	2,279
Equity method income (loss)	9,412	(9,740)	—	(328)
Interest expense	73,429	521	(81)	73,869
Income (loss) before income taxes	204,138	(9,091)	—	195,047
Income tax expense (benefit)	35,970	(9,857)	—	26,113
Income attributable to IDACORP, Inc.	168,168	593	—	168,761
Total assets	5,215,711	115,748	(11,943)	5,319,516
Expenditures for long-lived assets	239,761	27	—	239,788

	Utility Operations	All Other	Eliminations	Consolidated Total
2011				
Revenues	$ 1,022,728	$ 4,028	$ —	$ 1,026,756
Operating income (loss)	155,470	(118)	—	155,352
Other income	27,772	30	—	27,802
Interest income	2,146	233	(76)	2,303
Equity method income (loss)	9,018	(8,220)	—	798
Interest expense	71,055	547	(76)	71,526
Income (loss) before income taxes	123,351	(8,622)	—	114,729
Income tax benefit	(41,399)	(10,734)	—	(52,133)
Income attributable to IDACORP, Inc.	164,750	1,943	—	166,693
Total assets	4,856,839	122,678	(18,908)	4,960,609
Expenditures for long-lived assets	337,765	5	—	337,770
2010				
Revenues	$ 1,033,052	$ 2,977	$ —	$ 1,036,029
Operating income (loss)	193,514	(1,703)	—	191,811
Other income	18,361	623	—	18,984
Interest income	2,116	1,023	(99)	3,040
Equity method income (loss)	11,281	(8,273)	—	3,008
Interest expense	73,925	1,288	(99)	75,114
Income (loss) before income taxes	151,347	(9,618)	—	141,729
Income tax expense (benefit)	10,713	(11,444)	—	(731)
Income attributable to IDACORP, Inc.	140,634	2,164	—	142,798
Total assets	4,568,393	131,553	(23,891)	4,676,055
Expenditures for long-lived assets	338,252	—	—	338,252

18. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's Other income, net (in thousands of dollars):

	2012	2011	2010
Investment income, net	$ 2,280	$ 2,305	$ 3,046
Carrying charges on regulatory assets	1,714	1,665	921
Other income	409	107	1,886
Life insurance proceeds, net of premiums	14	757	(93)
Other expenses	(208)	(213)	(287)
Total	$ 4,209	$ 4,621	$ 5,473

IDACORP management identified certain operating expenses, primarily consisting of SMSP expense, totaling $8.9 million and $6.9 million in 2011 and 2010, respectively, which had been erroneously reported as a reduction to "Other Income, net" in the previously issued IDACORP financial statements rather than as a reduction to "Operating Income." Accordingly, such classification has been corrected in the accompanying 2011 and 2010 consolidated statements of income by including these costs within "Other" operating expenses. The restated items are also reflected in the information presented in Note 17. Such items had no effect on the previously issued consolidated financial statements of Idaho Power and the previously issued consolidated balance sheets, consolidated statements of cash flows, or consolidated statements of equity of IDACORP.

The following table presents the components of Idaho Power's Other expense, net (in thousands of dollars):

	2012	2011	2010
Investment income, net	$ 1,980	$ 2,148	$ 2,312
Carrying charges on regulatory assets	1,714	1,665	921
Other income	271	57	1,680
SMSP expense	(7,111)	(6,579)	(5,709)
Life insurance proceeds, net of premiums	14	757	(93)
Other expense	(1,850)	(2,510)	(1,979)
Total	$ (4,982)	$ (4,462)	$ (2,868)

19. 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 each year from 2010 to 2012.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million to Ida-West in 2012 and 2011, and $8 million in 2010.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
February 21, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
February 21, 2013

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2012 and 2011 (in thousands of dollars, except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	June 30	September 30	December 31
IDACORP, Inc.				
2012				
Revenues	$ 241,140	$ 254,701	$ 334,019	$ 250,801
Operating income	39,860	56,474	109,277	36,991
Net income	24,818	35,438	92,264	16,416
Net income attributable to IDACORP, Inc.	24,930	35,301	92,069	16,462
Basic earnings per share	0.50	0.71	1.84	0.33
Diluted earnings per share	0.50	0.71	1.84	0.33
2011				
Revenues	$ 251,494	$ 234,983	$ 309,630	$ 230,648
Operating income	47,882	32,031	69,406	6,033
Net income	29,488	20,977	107,414	8,983
Net income attributable to IDACORP, Inc.	29,740	20,901	107,067	8,985
Basic earnings per share	0.60	0.42	2.16	0.18
Diluted earnings per share	0.60	0.42	2.16	0.18
Idaho Power Company				
2012				
Revenues	$ 240,483	$ 253,547	$ 332,757	$ 249,938
Income from operations	42,814	58,478	111,083	38,329
Net income	25,819	34,709	89,596	18,043
2011				
Revenues	$ 251,062	$ 233,924	$ 308,045	$ 229,697
Income from operations	50,713	34,153	70,415	9,086
Net income	29,848	20,701	104,872	9,330

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures - IDACORP, Inc.

The Chief Executive Officer and Chief Financial Officer of IDACORP, Inc., based on their evaluation of IDACORP, Inc.'s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2012, have concluded that IDACORP, Inc.'s disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - IDACORP, Inc.

Management's Annual Report on Internal Control Over Financial Reporting

The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2012. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management concluded that, as of December 31, 2012, IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2012 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2012.

February 21, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2012 of the Company and our report dated February 21, 2013 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
February 21, 2013

Disclosure Controls and Procedures - Idaho Power Company

The Chief Executive Officer and Chief Financial Officer of Idaho Power Company, based on their evaluation of Idaho Power Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2012, have concluded that Idaho Power Company's disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - Idaho Power Company

Management's Annual Report on Internal Control Over Financial Reporting

The management of Idaho Power Company (Idaho Power) is responsible for establishing and maintaining adequate internal control over financial reporting of Idaho Power. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Idaho Power's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2012. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management concluded that, as of December 31, 2012, Idaho Power's internal control over financial reporting is effective based on those criteria.

Idaho Power's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2012 and issued a report which appears on the next page and expresses an unqualified opinion on the effectiveness of Idaho Power's internal control over financial reporting as of December 31, 2012.

February 21, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2012, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2012 of the Company and our report dated February 21, 2013 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Boise, Idaho
February 21, 2013

Changes in Internal Control Over Financial Reporting - IDACORP, Inc. and Idaho Power Company

There have been no changes in IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors - Nominees for Election - One-Year Term to Expire in 2014," "Information About Continuing Directors – Terms to Expire in 2014 (One-Year Terms Thereafter)," "Information About Continuing Directors - Terms to Expire in 2015 (One-Year Terms Thereafter)," "Information About Our Retiring Director - Term to Expire Immediately Prior to the 2013 Annual Meeting," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance - Committees of the Board of Directors - Audit Committee," "Corporate Governance Principles and Practices - Codes of Business Conduct," and "Corporate Governance Principles and Practices - Related Person Transactions in 2012" to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders are hereby incorporated by reference.

Information regarding IDACORP's executive officers required by this item appears in Item 1 of this report under "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers, and Five-Percent Shareholders" to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders is hereby incorporated by reference.

The following table includes information as of December 31, 2012 with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP) and the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP).

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders [(1)]	15,206	$ 29.64	1,387,101 [(2)]
Equity compensation plans not approved by shareholders	—	$ —	—
Total	15,206	$ 29.64	1,387,101

(1) Consists of the RSP and the LTICP.

(2) In addition to being available for future issuance upon exercise of options, 1,371,305 shares under the LTICP may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares, or other equity-based awards as of December 31, 2012. 15,796 shares remain available for future issuance under the RSP. The number of shares listed in this column excludes (i) issued but unvested performance-based restricted shares assuming achievement of the target level of performance, and (ii) issued but unvested time-based restricted shares, in both cases issued pursuant to the RSP and LTICP and unvested as of December 31, 2012.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Certain Relationships and Related Transactions" and "Corporate Governance Principles and Practices – Director Independence and Executive Sessions" to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders are hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP: The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2013 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees our principal independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill to Idaho Power for the fiscal years ended December 31, 2012 and 2011:

	2012	2011
Audit fees	$ 1,156,589	$ 1,047,708
Audit-related fees[(1)]	93,700	91,700
Tax fees[(2)]	43,236	87,648
All other fees[(3)]	2,200	2,200
Total	$ 1,295,725	$ 1,229,256

[(1)] Audits of Idaho Power's benefit plans and compliance audit for the U.S. DOE Smart Grid Investment Grant Program.

[(2)] Includes fees for benefit plan tax returns and consultation related to tax accounting method changes.

[(3)] Accounting research tool subscription.

Policy on Audit Committee Pre-Approval:

Idaho Power and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, the Audit Committee has established and periodically reviews a pre-approval policy for audit and non-audit services. For 2011 and 2012, all audit and non-audit services and all fees paid in connection with those services were pre-approved by the Audit Committee.

In addition to the audits of Idaho Power's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax, and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include: audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed services; however, the Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to Idaho Power's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee, and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel, and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations, and whether the nature of the engagement and the related fees are consistent with the following principles:

- the independent public accounting firm cannot function in the role of management of Idaho Power; and
- the independent public accounting firm cannot audit its own work.

The pre-approval policy and separate supplements to the pre-approval policy describe the specific audit, audit related, tax, and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of all consolidated financial statements and financial statement schedules.

(3) Exhibits.

Note Regarding Reliance on Statements in Agreements: The agreements filed as exhibits to this Annual Report on Form 10-K are filed to provide information regarding their terms and are not intended to provide any other factual or disclosure information about IDACORP, Inc., Idaho Power Company, or the other parties to the agreements. Some of the agreements contain statements, representations, and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (a) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate; (b) have been qualified by disclosures that were made to the other party, which disclosures are not necessarily reflected in the agreement; (c) may apply standards of materiality in a way that is different from what may be viewed as material to investors; and (d) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, readers should not rely upon the statements, representations, or warranties made in the agreements.

Exhibit No.	Exhibit Description	Incorporated by Reference: Form	File No.	Exhibit No.	Date	Included Herewith
2	Agreement and Plan of Exchange between IDACORP, Inc. and Idaho Power Company, dated as of February 2, 1998	S-4	333-48031	A	3/16/1998	
3.1	Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on June 30, 1989	S-3 Post-Effective Amend. No. 2	33-00440	4(a)(xiii)	6/30/1989	
3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on November 5, 1991	S-3	33-65720	4(a)(ii)	7/7/1993	
3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on June 30, 1993	S-3	33-65720	4(a)(iii)	7/7/1993	
3.4	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998	S-8 Post-Effective Amend. No. 1	33-56071-9 9	3(d)	10/1/1998	
3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000	10-Q	1-3198	3(a)(iii)	8/4/2000	
3.6	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005	8-K	1-3198	3.3	1/26/2005	
3.7	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007	8-K	1-3198	3.3	11/19/2007	
3.8	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-3198	3.14	5/21/2012	
3.9	Amended Bylaws of Idaho Power Company, amended on November 15, 2007 and presently in effect	8-K	1-3198	3.2	11/19/2007	
3.10	Articles of Incorporation of IDACORP, Inc.	S-3	333-64737	3.1	11/4/1998	
3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998	S-3 Amend. No. 1	333-64737	3.2	11/4/1998	
3.12	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998	S-3 Post-Effective Amend. No. 1	333-00139-99	3(b)	9/22/1998	
3.13	Articles of Amendment to Articles of Incorporation of IDACORP, Inc., as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-14465	3.13	5/21/2012	
3.14	Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect	8-K	1-14465	3.1	11/19/2007	
4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees		2-3413	B-2		
4.2	Idaho Power Company Supplemental Indentures to Mortgage and Deed of Trust:					
	File number 1-MD, as Exhibit B-2-a, First, July 1, 1939					
	File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943					
	File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947					
	File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948					
	File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949					
	File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951					
	File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957					
	File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957					

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
	File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957					
	File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958					
	File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958					
	File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959					
	File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960					
	File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961					
	File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964					
	File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966					
	File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966					
	File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972					
	File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974					
	File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974					
	File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974					
	File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976					
	File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978					
	File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979					
	File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981					
	File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982					
	File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986					
	File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989					
	File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990					
	File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991					
	File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991					
	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992					
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993					
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993					
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000					
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001					
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003					
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003					
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iv), Thirty-ninth, October 1, 2003					
	File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005					
	File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006					
	File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007					
	File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007					
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008					
	File number 1-3198, Form 10-K filed on 2/23/10, as Exhibit 4.10, Forty-fifth, February 1, 2010					
	File number 1-3198, Form 8-K filed on 6/18/10, as Exhibit 4, Forty-sixth, June 1, 2010					
4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.4)	10-Q	1-3198	4(b)	8/4/2000	
4.4	Agreement of Idaho Power Company to furnish certain debt instruments	S-3	33-65720	4(f)	7/7/1993	
4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments	10-Q	1-14465	4(c)(ii)	11/6/2003	
4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation	S-3 Post-Effective Amend. No. 2	33-00440	2(a)(iii)	6/30/1989	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.1	2/28/2001	
4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.2	2/28/2001	
4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	S-3	333-67748	4.13	8/16/2001	
4.10	Idaho Power Company Instrument of Further Assurance relating to Mortgage and Deed of Trust, dated as of August 3, 2010	10-Q	1-3198	4.12	8/5/2010	
10.1	Agreements, dated September 22, 1969, between Idaho Power Company and Pacific Power & Light Company, relating to the operation, construction, and ownership of the Jim Bridger Project		2-49584	5(b)		
10.2	Amendment, dated February 1, 1974, relating to the agreement filed as Exhibit 10.1		2-51762	5(c)		
10.3	Agreement, dated as of October 11, 1973, between Idaho Power Company and Pacific Power & Light Company		2-49584	5(c)		
10.4	Guaranty Agreement, dated April 11, 2000, between Idaho Power Company and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho	10-Q	1-3198	10(c)	8/4/2000	
10.5	Guaranty Agreement, dated as of August 30, 1974, between Idaho Power Company and Pacific Power & Light Company	S-7	2-62034	5(r)	6/30/1978	
10.6	Letter Agreement, dated January 23, 1976, between Idaho Power Company and Portland General Electric Company		2-56513	5(i)		
10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and Idaho Power Company	S-7	2-62034	5(s)	6/30/1978	
10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6	S-7	2-62034	5(t)	6/30/1978	
10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6	S-7	2-62034	5(u)	6/30/1978	
10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6	S-7	2-62034	5(v)	6/30/1978	
10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6	S-7	2-62034	5(w)	6/30/1978	
10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6	S-7	2-68574	5(x)	7/23/1980	
10.13	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir	S-7	2-68574	5(z)	7/23/1980	
10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and Idaho Power Company	S-7	2-64910	5(y)	6/29/1979	
10.15	Framework Agreement, dated October 1, 1984, between the State of Idaho and Idaho Power Company relating to Idaho Power Company's Swan Falls and Snake River water rights	S-3	33-65720	10(h)	7/7/1993	
10.16	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.15	S-3	33-65720	10(h)(i)	7/7/1993	

Exhibit No.	Exhibit Description	Incorporated by Reference: Form	File No.	Exhibit No.	Date	Included Herewith
10.17	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.15.	10-Q	1-14465	10.58	5/7/2009	
10.18	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.15	S-3	33-65720	10(h)(ii)	7/7/1993	
10.19	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between Idaho Power Company and the Twin Falls Canal Company and the Northside Canal Company Limited	S-3	33-65720	10(m)	7/7/1993	
10.20	Hemingway Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp	10-Q	1-14465, 1-3198	10.70	8/5/2010	
10.21	Populus Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp	10-Q	1-14465, 1-3198	10.71	8/5/2010	
10.22[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008	10-K	1-14465, 1-3198	10.15	2/26/2009	
10.23[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees I	10-Q	1-14465, 1-3198	10.62	11/1/2012	
10.24[1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 30, 2011	10-K	1-14465, 1-3198	10.21	2/22/2012	
10.25[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees II	10-Q	1-14465, 1-3198	10.63	11/1/2012	
10.26[1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007	10-Q	1-14465, 1-3198	10(h)(iii)	10/31/2007	
10.27[1]	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006).	10-Q	1-14465, 1-3198	10(h)(vi)	11/2/2006	
10.28[1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006)	10-Q	1-14465, 1-3198	10(h) (vii)	11/2/2006	
10.29[1]	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006	10-Q	1-14465, 1-3198	10(h) (viii)	11/2/2006	
10.30[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended January 19, 2012	10-K	1-14465, 1-3198	10.26	2/22/2012	
10.31[1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xix)	11/2/2006	
10.32[1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xx)	11/2/2006	
10.33[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (senior vice president and higher), approved November 20, 2008	10-K	1-14465, 1-3198	10.24	2/26/2009	
10.34[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (below senior vice president), approved November 20, 2008	10-K	1-14465, 1-3198	10.25	2/26/2009	
10.35[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, approved March 17, 2010	8-K	1-14465, 1-3198	10.1	3/24/2010	
10.36[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of January 1, 2013					X
10.37[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 18, 2010	10-K	1-14465, 1-3198	10.33	2/23/2011	

Exhibit No.	Exhibit Description	Incorporated by Reference: Form	File No.	Exhibit No.	Date	Included Herewith
10.38[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006)	10-Q	1-14465, 1-3198	10(h) (xvi)	11/2/2006	
10.39[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006)	10-Q	1-14465, 1-3198	10(h) (xvii)	11/2/2006	
10.40[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance vesting) (November 20, 2008)	10-K	1-14465, 1-3198	10.30	2/26/2009	
10.41[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (February 25, 2011)	10-Q	1-14465, 1-3198	10.69	5/5/2011	
10.42[1]	IDACORP, Inc. Executive Incentive Plan, as amended March 18, 2010 and approved May 20, 2010	8-K	1-14465, 1-3198	10.1	5/21/2010	
10.43[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008	10-K	1-14465, 1-3198	10.32	2/26/2009	
10.44[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, as amended January 21, 2010	10-K	1-14465, 1-3198	10.33	2/23/2010	
10.45[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.46	2/26/2009	
10.46[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.47	2/26/2009	
10.47[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.48	2/26/2009	
10.48[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.49	2/26/2009	
10.49[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.50	2/26/2009	
10.50[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.51	2/26/2009	
10.51[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.52	2/26/2009	
10.52[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.53	2/26/2009	
10.53[1]	Idaho Power Company Employee Savings Plan, as amended and restated as of January 1, 2010 (revised)	10-K	1-14465, 1-3198	10.63	2/23/2010	
10.54[1]	Amendment to the Idaho Power Company Employee Savings Plan, dated August 31, 2011	10-Q	1-14465, 1-3198	10.72	11/3/2011	
10.55[1]	Amendment to the Idaho Power Company Employee Savings Plan, dated November 29, 2011	10-Q	1-14465, 1-3198	10.61	8/2/2012	
10.56	Second Amended and Restated Credit Agreement, dated October 26, 2011, among IDACORP, Inc., various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners	8-K	1-14465	10.70	10/28/2011	
10.57	First Extension Agreement, dated October 12, 2012, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.56	10-Q	1-14465	10.64	11/1/2012	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.58	Second Amended and Restated Credit Agreement, dated October 26, 2011, among Idaho Power Company, various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners	8-K	1-3198	10.71	10/28/2011	
10.59	First Extension Agreement, dated October 12, 2012, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.58	10-Q	1-3198	10.65	11/1/2012	
10.60	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.61	Guaranty Agreement, dated February 10, 1992, between Idaho Power Company and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc.	S-3	33-65720	10(m)(i)	7/7/1993	
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
21.1	Subsidiaries of IDACORP, Inc.					X
23.1	Consent of Registered Independent Accounting Firm					X
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification					X
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification					X
31.3	Idaho Power Rule 13a-14(a) CEO certification					X
31.4	Idaho Power Rule 13a-14(a) CFO certification					X
32.1	IDACORP, Inc. Section 1350 CEO certification					X
32.2	IDACORP, Inc. Section 1350 CFO certification					X
32.3	Idaho Power Section 1350 CEO certification					X
32.4	Idaho Power Section 1350 CFO certification					X
95.1	Mine Safety Disclosures					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X

[1] Management contract or compensatory plan or arrangement

IDACORP, INC.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 168,591	$ 166,716	$ 143,414
Investment income (losses)	295	161	602
Total income	168,886	166,877	144,016
Expenses:			
Operating expenses	473	1,011	1,130
Interest expense	511	534	1,023
Other expenses	45	—	57
Total expenses	1,029	1,545	2,210
Income from Before Income Taxes	167,857	165,332	141,806
Income Tax Benefit	(904)	(1,361)	(992)
Net Income Attributable to IDACORP, Inc.	168,761	166,693	142,798
Other comprehensive income	(5,494)	(2,054)	(1,301)
Comprehensive Income Attributable to IDACORP, Inc.	$ 163,267	$ 164,639	$ 141,497

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 61,876	$ 74,618	$ 29,303
Investing Activities:			
Contributions to subsidiaries	(7,525)	(16,000)	(50,000)
Sale of investments	—	621	553
Net cash used in investing activities	(7,525)	(15,379)	(49,447)
Financing Activities:			
Issuance of common stock	4,882	17,501	48,644
Dividends on common stock	(68,928)	(59,668)	(57,872)
Increase (decrease) in short-term borrowings	15,500	(12,700)	13,150
Change in intercompany notes payable	(2,308)	(805)	(8,266)
Other	(3,147)	(1,612)	(1,051)
Net cash used in financing activities	(54,001)	(57,284)	(5,395)
Net (decrease) increase in cash and cash equivalents	350	1,955	(25,539)
Cash and cash equivalents at beginning of year	3,186	1,231	26,770
Cash and cash equivalents at end of year	$ 3,536	$ 3,186	$ 1,231

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 3,536	$ 3,186
Receivables	1,895	2,751
Deferred income taxes	5,581	2,048
Other	119	118
Total current assets	11,131	8,103
Investment in subsidiaries	1,741,335	1,641,479
Other Assets:		
Deferred income taxes	90,374	82,250
Other	457	473
Total other assets	90,831	82,723
Total assets	$ 1,843,297	$ 1,732,305
Liabilities and Shareholders' Equity		
Current Liabilities:		
Notes payable	$ 69,700	$ 54,200
Accounts payable	6,042	6,183
Taxes accrued	1,352	4,376
Other	624	669
Total current liabilities	77,718	65,428
Other Liabilities:		
Intercompany notes payable	4,840	7,149
Other	1,986	2,074
Total other liabilities	6,826	9,223
IDACORP, Inc. Shareholders' Equity	1,758,753	1,657,654
Total Liabilities and Shareholders' Equity	$ 1,843,297	$ 1,732,305

The accompanying note is an integral part of these statements.

NOTE TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2012 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries: IDACORP has accounted for the earnings of its subsidiaries under the equity method in the unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends of $71 million, $63 million, and $61 million that IDACORP subsidiaries paid to IDACORP in 2012, 2011, and 2010, respectively.

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2012, 2011, and 2010

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2012:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,435	$ 4,524	$ 283	$ 4,369	$ 1,873
Reserve for uncollectible notes	2,743	(1,483)	—	—	1,260
Other Reserves:					
Injuries and damages	1,925	4,481 [2]	—	926	5,480
2011:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,640	$ 4,277	$ 161	$ 4,643	$ 1,435
Reserve for uncollectible notes	3,190	(447)	—	—	2,743
Other Reserves:					
Injuries and damages	1,882	783	—	740	1,925
Miscellaneous operating reserves	2,611	—	—	2,611	—
2010:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,990	$ 5,764	$ (324)	$ 5,790	$ 1,640
Reserve for uncollectible notes	3,045	444	—	299	3,190
Other Reserves:					
Injuries and damages	3,413	400	—	1,931	1,882
Miscellaneous operating reserves	2,926	10	—	325	2,611

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, and notes reserves, includes reversals of amounts previously written off.
[2] Of the injuries and damages indicated as "Charged to Income," $3.4 million is recoverable from insurance.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2012, 2011, and 2010

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
	(thousands of dollars)				
2012:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,435	$ 4,524	$ 283	$ 4,369	$ 1,873
Other Reserves:					
Injuries and damages	1,925	4,481 [2]	—	926	5,480
2011:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,640	$ 4,277	$ 161	$ 4,643	$ 1,435
Other Reserves:					
Injuries and damages	1,882	783	—	740	1,925
Miscellaneous operating reserves	2,611	—	—	2,611	—
2010:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,990	$ 5,764	$ (324)	$ 5,790	$ 1,640
Other Reserves:					
Injuries and damages	3,413	400	—	1,931	1,882
Miscellaneous operating reserves	2,926	10	—	325	2,611

(1) Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, includes reversals of amounts previously written off.
(2) Of the injuries and damages indicated as "Charged to Income," $3.4 million is recoverable from insurance.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 21, 2013 — IDACORP, INC.

Date

By: */s/ J. LaMont Keen*

J. LaMont Keen

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gary G. Michael Gary G. Michael	Chairman of the Board	February 21, 2013
/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer and Director	(Principal Executive Officer)	February 21, 2013
/s/ Darrel T. Anderson Darrel T. Anderson Executive Vice President-Administrative Services and Chief Financial Officer	(Principal Financial Officer)	February 21, 2013
/s/ Kenneth W. Petersen Kenneth W. Petersen Corporate Controller and Chief Accounting Officer	(Principal Accounting Officer)	February 21, 2013
/s/ C. Stephen Allred C. Stephen Allred	Director	February 21, 2013
/s/ Richard J. Dahl Richard J. Dahl	Director	February 21, 2013
/s/ Judith A. Johansen Judith A. Johansen	Director	February 21, 2013
/s/ Christine King Christine King	Director	February 21, 2013
/s/ Jan B. Packwood Jan B. Packwood	Director	February 21, 2013
/s/ Joan H. Smith Joan H. Smith	Director	February 21, 2013
/s/ Robert A. Tinstman Robert A. Tinstman	Director	February 21, 2013
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 21, 2013

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 21, 2013		Idaho Power Company
Date		
	By:	*/s/ J. LaMont Keen*
		J. LaMont Keen
		Chief Executive Officer

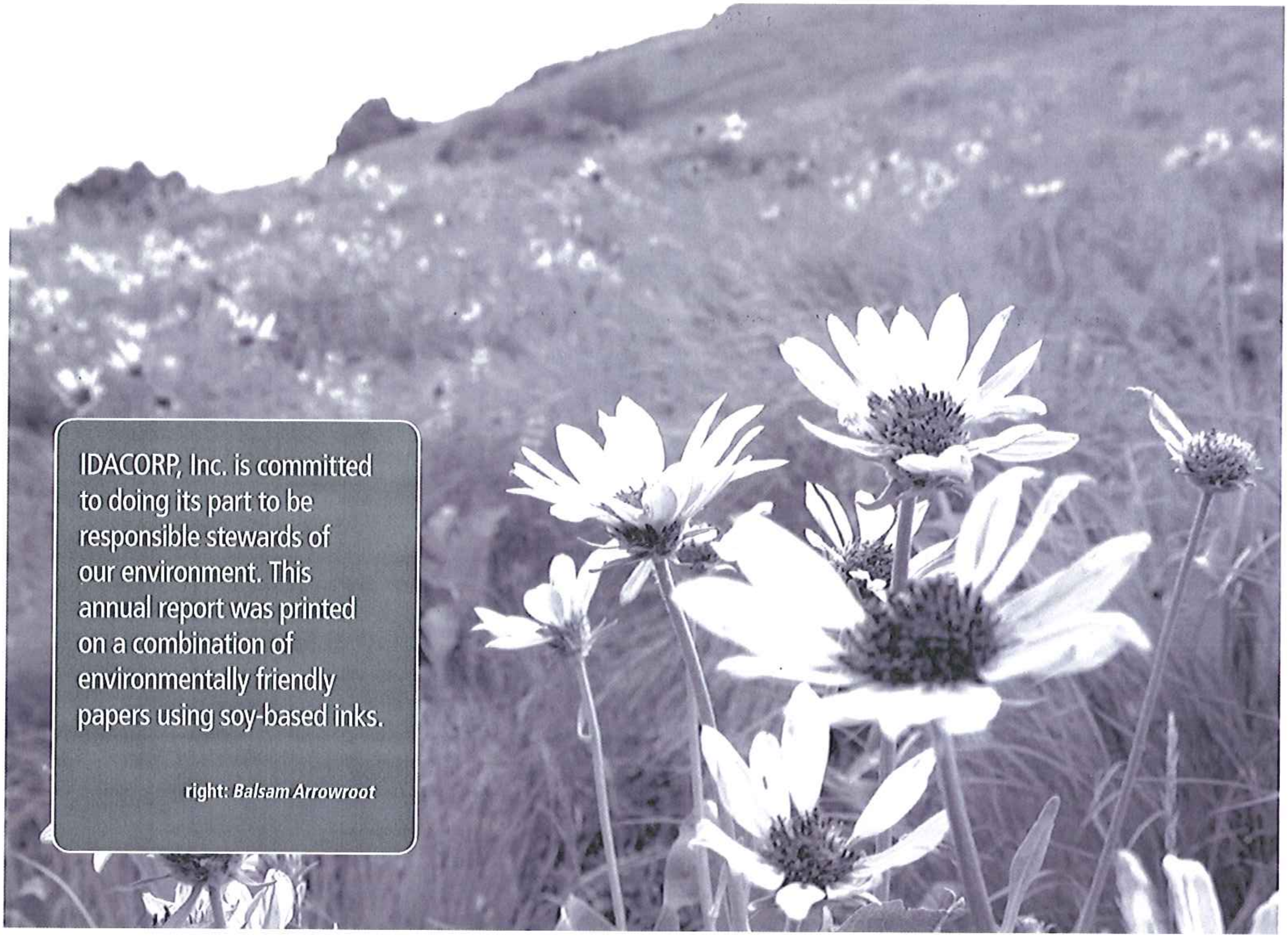
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gary G. Michael Gary G. Michael	Chairman of the Board	February 21, 2013
/s/ J. LaMont Keen J. LaMont Keen Chief Executive Officer and Director	(Principal Executive Officer)	February 21, 2013
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Financial Officer	(Principal Financial Officer)	February 21, 2013
/s/ Kenneth W. Petersen Kenneth W. Petersen Corporate Controller and Chief Accounting Officer	(Principal Accounting Officer)	February 21, 2013
/s/ C. Stephen Allred C. Stephen Allred	Director	February 21, 2013
/s/ Richard J. Dahl Richard J. Dahl	Director	February 21, 2013
/s/ Judith A. Johansen Judith A. Johansen	Director	February 21, 2013
/s/ Christine King Christine King	Director	February 21, 2013
/s/ Jan B. Packwood Jan B. Packwood	Director	February 21, 2013
/s/ Joan H. Smith Joan H. Smith	Director	February 21, 2013
/s/ Robert A. Tinstman Robert A. Tinstman	Director	February 21, 2013
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 21, 2013

EXHIBIT INDEX

Exhibit No.	Description
10.36[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of January 1, 2013
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
21.1	Subsidiaries of IDACORP, Inc.
23.1	Consent of Independent Registered Public Accounting Firm
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification
31.3	Idaho Power Rule 13a-14(a) CEO certification
31.4	Idaho Power Rule 13a-14(a) CFO certification
32.1	IDACORP, Inc. Section 1350 CEO certification
32.2	IDACORP, Inc. Section 1350 CFO certification
32.3	Idaho Power Section 1350 CEO certification
32.4	Idaho Power Section 1350 CFO certification
95.1	Mine safety disclosures
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

[1] Management contract or compensatory plan or arrangement.



IDACORP, Inc. is committed to doing its part to be responsible stewards of our environment. This annual report was printed on a combination of environmentally friendly papers using soy-based inks.

right: *Balsam Arrowroot*

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10	trees preserved for the future
29	pounds of water-borne waste not created
4,228	gallons of wastewater flow saved
468	pounds of solid waste not generated
921	pounds net greenhouse gases prevented

As compared to the industry average, the amount of greenhouse gas emissions avoided are equivalent to one of the following:

126	gallons of gasoline consumed
47	propane cylinders
758	pounds of waste recycled instead of sent to landfills

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IDACORP and Idaho Power Board of Directors (as of Feb. 21, 2013)

( ) year elected to the board
* Chairman of the Board

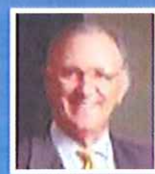
C. Stephen Allred
(2009) Boise, Idaho
Formerly Assistant Secretary for U.S. Land and Minerals Management; formerly Director of the Idaho Department of Environmental Quality; formerly Director of Idaho Department of Water Resources; and formerly President of Morrison-Knudsen's Environmental and Government Services Group

Richard J. Dahl
(2008) Kapolei, Hawaii
Chairman of the Board, President and Chief Executive Officer of James Campbell Company, LLC; Chairman of the Board, International Rectifiers Corp; Director, DineEquity, Inc.; and formerly President and Chief Operating Officer of Dole Food Company

Judith A. Johansen
(2007) Lake Oswego, Oregon
President of Marylhurst University; Director, Cascade Bancorp, Schnitzer Steel and Roseburg Forest Products; formerly President and Chief Executive Officer of PacifiCorp; and formerly Chief Executive Officer and Administrator of Bonneville Power Administration

J. LaMont Keen
(2004) Boise, Idaho
President and Chief Executive Officer, IDACORP, Inc. and Chief Executive Officer, Idaho Power; Board of Directors, Cascade Bancorp

Christine King
(2006) Scottsdale, Arizona
Former President and Chief Executive Officer of Standard Microsystems Corporation; former Director of Atheros Communications, Inc., Open-Silicon, Inc., and Standard Microsystems Corporation; and former President and Chief Executive Officer of AMI Semiconductor.



Gary G. Michael*
(2001) Boise, Idaho
Chairman of the Board, IDACORP, Inc. and Idaho Power; Director, The Clorox Co., Questar Corporation, Questar Gas, Questar Pipeline; former Director of Graham Packaging Co.; and formerly Chief Executive Officer of Albertsons, Inc.

Jan B. Packwood
(1997) Boise, Idaho
Formerly President and Chief Executive Officer of IDACORP, Inc.; Director of Westmoreland Coal Company

Joan H. Smith
(2004) Portland, Oregon
Self-employed consultant, consulting on regulatory strategy and telecommunications; and formerly Oregon Public Utility Commissioner

Robert A. Tinstman
(1999) Boise, Idaho
Director, Primoris Services Corp.; Home Federal Bancorp, Inc.; former Director of CNA Surety Corp.; and formerly President and Chief Executive Officer of Morrison-Knudsen Corporation

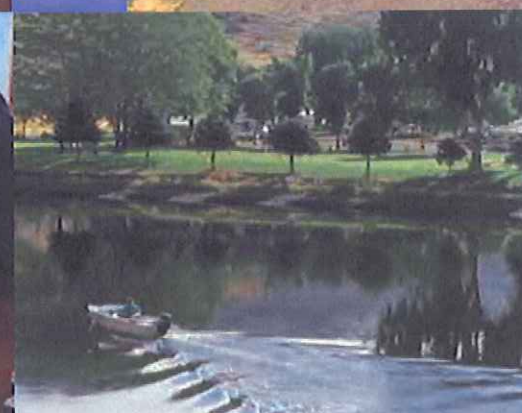
Thomas J. Wilford
(2004) Boise, Idaho
Formerly President of Alscott, Inc.; formerly Chief Executive Officer of J.A. and Kathryn Albertson Foundation, Inc.; former Director, K12, Inc.

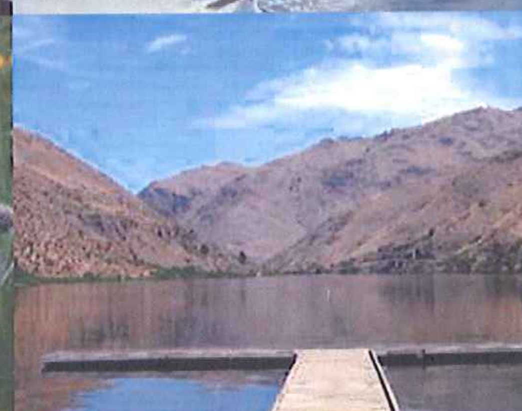










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