THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

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UTILITIES COMMISSION

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

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 2010/Q4

Deloitte.

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Deloitte & Touche LLP
Suite 1700
101 South Capitol Boulevard
Boise, ID 83702-7717
USA

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

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the balance sheet — regulatory basis of Idaho Power Company (the "Company") as of December 31, 2010, and the related statements of income — regulatory basis; retained earnings — regulatory basis, and cash flows — regulatory basis, for the year ended December 31, 2010, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2010, and the results of its operations and its cash flows for the year ended December 31, 2010, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

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

Deloitte & Touche LLP

February 23, 2011

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company			02 Year/Period of Report End of 2010/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 Street, 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 Street, P.O. Box 70 Boise, Id 83707-0070			
08 Telephone of Contact Person, *Including Area Code* (208) 388-2761	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission		10 Date of Report *(Mo, Da, Yr)* 04/15/2011

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Ken Petersen	03 Signature Ken Petersen	04 Date Signed *(Mo, Da, Yr)* 04/15/2011
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.

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

GENERAL INFORMATION

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

Ken Petersen Corporate 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
"	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	04/15/2011	End of 2010/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	J. LaMont Keen	620,000
3			
4	Executive VP, Administrative Services & CFO	Darrel T. Anderson	365,000
5			
6	Executive Vice President, Operations	Dan Minor	340,000
7			
8	Senior Vice President, Corporate Responsibilty (1)	Ric Gale	235,000
9			
10	Vice President and Chief Information Officer	Dennis Gribble	205,000
11			
12	Vice President, Human Resources & Corp Services (1)	Luci McDonald	215,000
13			
14	Vice President Finance and Treasurer (1)	Steven R. Keen	221,000
15			
16	Senior Vice President , General Counsel	Rex Blackburn	245,000
17			
18	Vice President Chief Risk Officer (1)	Lori Smith	200,000
19			
20	Senior Vice President, Power Supply	Lisa Grow	220,000
21			
22	Vice President Public Affairs	Jeffrey Malmen	192,500
23			
24	Vice President, Customer Operations (1)	Warren Kline	175,000
25			
26	Vice President Engineering & Operations	Vern Porter	175,000
27			
28	Corporate Controller & Chief Accounting Officer (1)	Ken Petersen	160,000
29			
30	Vice President, Supply Chain (1)	Naomi Crafton-Shankel	159,000
31			
32	Corporate Secretary	Patrick Harrington	159,000
33			
34			
35	(1) Title/Position Change effective 5/29/10		
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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	04/15/2011	End of 2010/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A Johansen	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
3		
4	Christine King	Standard Microsystems Corporation
5		80 Arkay Dr, Hauppauge, NY 11788
6		
7	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
8		
9	Stephen Allred	4642 W Dawson Dr Meridian, Id 83646
10		
11	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
12		
13	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	Richard G. Reiten	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
17		Portland, Oregon 97204
18		
19	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
20		
21	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
22		
23	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
24		
25	Richard Dahl ***	11659 Presilla Road, Santa Rosa Valley Ca, 93012
26		
27	Jon H. Miller *** (1)	P.O.Box 1557, Boise, Idaho 83701
28		
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31	(1) Retired May 20, 2010	
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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	04/15/2011	End of 2010/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 First Revised Volume No. 6	FERC Docket No. ER06-787-002,003
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[X] Yes [ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20100826-5058	08/26/2010	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2010-2011 Annual	first revised volume
3				informational filing	
4				under ER09-1641	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	N/A			
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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 106, 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. In April 2010, Idaho Power Company sold Goshen capacitor bank to Pacificorp. The plant investment balance was $7.4 million and net book value was $6.5 million. Oregon Public Service Commission #10-010 and Idaho Public Utility Commission Case # IPC-E-09-32.

In March 2010, Idaho Power Company sold Border Feeder to Raft River Electric for $43,191. Idaho Public Utility Commission Case # IPC-E-09-31.

4. None

5. New station Hemingway Transmission Station, Owyhee County Idaho. 500Kv

New transmissin line- Line #725 230Kv Hemingway to Bowmont 41.34 miles

Addition to existing line - Line #221 69Kv extended thry Sage Station to Ontario Junction 39.38 miles.

In connection with the Memorandum of Understanding (MOU), on April 30, 2010, Idaho Power entered into a Joint Purchase and Sale Agreement with PacifiCorp, pursuant to which Idaho Power agreed to sell to PacifiCorp a 59.0 percent interest in certain high-voltage transmission-related and interconnection equipment located at the Hemingway station south of Boise, Idaho, and PacifiCorp agreed to sell to Idaho Power a 20.8 percent interest in certain high-voltage transmission-related and interconnection equipment located at PacifiCorp's Populus station in southeast Idaho. Closing of the purchase and sale occured on May 3, 2010. Construction of the Hemingway and Populus station is substantially complete.Upon final completion, the estimated purchase price PacifiCorp will have paid to Idaho Power for PacifiCorp's interest in the Hemingway station is $13.4 million, and the estimated purchase price Idaho Power will have paid to PacifiCorp for Idaho Power's interest in the Populus station is $14.3 million.

6. On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement. As of December 31, 2010, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities. State Commission order number is the same for both issuance OPUC UF4263, IPC-E-10-10, WPSC 20005-32-ES-10.

7. None

8. Effective 1/9/10 a 2.5% general wage increase was approved.

9. See pages 123.19 to 123.24

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a couple of changes in the major security holders for 2010. The top ten institutional shareholders list saw 2 changes from 3rd quarter to 4th quarter. In 4th quarter Zimmer Lucas Partners LLC and TIAA - CREF replaced American Century Investment Mgmt and Northern Trust Investments.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	4,339,130,398	4,167,328,769
3	Construction Work in Progress (107)	200-201	416,949,593	289,188,358
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,756,079,991	4,456,517,127
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,771,654,529	1,713,943,062
6	Net Utility Plant (Enter Total of line 4 less 5)		2,984,425,462	2,742,574,065
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)		2,984,425,462	2,742,574,065
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,074,996	1,335,962
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	72,561,774	65,015,441
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)		2,511	266,768
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		29,306,774	24,059,095
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	212,580
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		103,946,055	90,889,846
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		73,015,293	2,485,630
36	Special Deposits (132-134)		2,802,631	1,496,698
37	Working Fund (135)		44,850	39,350
38	Temporary Cash Investments (136)		151,172,575	19,100,000
39	Notes Receivable (141)		303,143	636,667
40	Customer Accounts Receivable (142)		63,612,796	76,792,157
41	Other Accounts Receivable (143)		6,166,234	9,087,713
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,641,302	1,990,343
43	Notes Receivable from Associated Companies (145)		14,384,928	18,894,101
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	27,546,983	25,633,645
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	42,221,176	43,342,060
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

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	3,379,745	4,711,966
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)		10,910,213	10,959,775
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		8,128	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		47,964,339	51,271,984
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		573,226	715,249
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	212,580
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)		442,464,958	262,964,072
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,869,453	11,520,092
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	761,425,884	715,831,853
73	Prelim. Survey and Investigation Charges (Electric) (183)		454,727	442,448
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)		564,213	523,636
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	55,131,472	58,492,874
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)		14,524,712	15,439,928
82	Accumulated Deferred Income Taxes (190)	234	157,346,772	170,110,978
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,005,317,233	972,361,809
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,536,153,708	4,068,789,792

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [x] An Original (2) [ ] A Resubmission	04/15/2011	end of 2010/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)		688,757,435	638,757,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	560,160,116	485,143,115
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	70,098,680	62,552,348
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)	-9,567,515	-8,266,663
16	Total Proprietary Capital (lines 2 through 15)		1,405,228,821	1,273,966,340
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,585,460,000	1,385,460,000
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	27,330,455	28,394,091
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,439,753	3,060,748
24	Total Long-Term Debt (lines 18 through 23)		1,609,350,702	1,410,793,343
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,881,776	3,412,806
29	Accumulated Provision for Pensions and Benefits (228.3)		268,433,659	279,806,510
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	916,667
31	Accumulated Provision for Rate Refunds (229)		21,210,538	9,894,077
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		16,951,914	16,239,594
35	Total Other Noncurrent Liabilities (lines 26 through 34)		308,477,887	310,269,654
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		100,785,053	81,164,595
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,110,373	1,735,649
41	Customer Deposits (235)		1,366,711	464,233
42	Taxes Accrued (236)	262-263	-12,242,872	-3,253,927
43	Interest Accrued (237)		24,038,150	20,383,712
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)		1,689,273	1,963,189
48	Miscellaneous Current and Accrued Liabilities (242)		112,230,437	29,912,569
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		508,141	280,459
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		229,485,266	132,650,479
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		23,054,017	25,180,998
57	Accumulated Deferred Investment Tax Credits (255)	266-267	71,972,336	73,505,525
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	26,668,269	19,363,271
60	Other Regulatory Liabilities (254)	278	55,279,902	49,478,079
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)		707,009,348	664,169,740
64	Accum. Deferred Income Taxes-Other (283)		99,627,160	109,412,363
65	Total Deferred Credits (lines 56 through 64)		983,611,032	941,109,976
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,536,153,708	4,068,789,792

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	1,033,052,120	1,045,996,381		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	622,124,906	638,946,792		
5	Maintenance Expenses (402)	320-323	71,096,344	69,458,827		
6	Depreciation Expense (403)	336-337	109,099,197	103,587,447		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,857,301	7,061,068		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		21,955			
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	24,046,035	21,069,235		
15	Income Taxes - Federal (409.1)	262-263	5,967,393	15,555,364		
16	- Other (409.1)	262-263	3,057,226	1,547,326		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	83,335,948	76,729,161		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	80,939,819	63,176,136		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,533,190	235,447		
20	(Less) Gains from Disp. of Utility Plant (411.6)		34,607			
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		444,212	297,616		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		842,631,754	870,694,192		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		190,420,366	175,302,189		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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
1,033,052,120	1,045,996,381					2
						3
622,124,906	638,946,792					4
71,096,344	69,458,827					5
109,099,197	103,587,447					6
						7
6,857,301	7,061,068					8
-22,723	-22,723					9
						10
						11
21,955						12
						13
24,046,035	21,069,235					14
5,967,393	15,555,364					15
3,057,226	1,547,326					16
83,335,948	76,729,161					17
80,939,819	63,176,136					18
-1,533,190	235,447					19
34,607						20
						21
444,212	297,616					22
						23
						24
842,631,754	870,694,192					25
190,420,366	175,302,189					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		190,420,366	175,302,189		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		802,483	782,667		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		625,141	737,018		
33	Revenues From Nonutility Operations (417)		58,915	66,599		
34	(Less) Expenses of Nonutility Operations (417.1)		657,070	1,076,858		
35	Nonoperating Rental Income (418)		-6,040	-8,226		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,546,332	4,957,254		
37	Interest and Dividend Income (419)		2,167,147	5,214,598		
38	Allowance for Other Funds Used During Construction (419.1)		16,551,145	7,554,922		
39	Miscellaneous Nonoperating Income (421)		1,928,056	7,178,192		
40	Gain on Disposition of Property (421.1)		122,735	122,587		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		27,888,562	24,054,717		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		3,355	3,973		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		440,052	420,891		
46	Life Insurance (426.2)		93,378	-4,197,136		
47	Penalties (426.3)		-453,479	328,368		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,098,260	1,050,861		
49	Other Deductions (426.5)		5,601,967	5,541,928		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,783,533	3,148,885		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	19,582	34,431		
53	Income Taxes-Federal (409.2)	262-263	-2,812,996	1,681,539		
54	Income Taxes-Other (409.2)	262-263	-559,924	352,526		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,739,465	3,224,256		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,420,220	3,576,029		
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)		-3,034,093	1,716,723		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		24,139,122	19,189,109		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		80,490,049	73,269,850		
63	Amort. of Debt Disc. and Expense (428)		1,487,918	1,225,978		
64	Amortization of Loss on Reaquired Debt (428.1)		915,215	776,937		
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)		1,707,178	2,057,420		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,675,095	5,397,871		
70	Net Interest Charges (Total of lines 62 thru 69)		73,925,265	71,932,314		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		140,634,223	122,558,984		
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)		140,634,223	122,558,984		

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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	04/15/2011	End of 2010/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		483,599,149	422,907,987
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)		133,087,891	117,601,730
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19	Reserve for excess Earnings for Cascade Project 2010		-54,644	
20	Reserve for execss Earnings for Twin Falls & American Falls	215100	-433,060	
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-487,704	
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-58,070,890	(56,910,568)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-58,070,890	(56,910,568)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		558,128,446	483,599,149
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		2,031,670	1,543,966
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		2,031,670	1,543,966
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		560,160,116	485,143,115
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		62,552,348	57,595,094
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,546,332	4,957,254
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		70,098,680	62,552,348

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Schedule Page: 118 Line No.: 20 Column: c

The excess earnings for these projects occurred in 1998 and 2000. Because the adjustment relates to prior years, the transfer was not recorded through account 436. Instead, it was recorded as a direct transfer to 215.1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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)	140,634,223	122,558,984
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	109,099,197	103,587,447
5	Amortization of	12,120,185	14,290,089
6			
7			
8	Deferred Income Taxes (Net)	75,464,788	10,594,321
9	Investment Tax Credit Adjustment (Net)	-984,156	2,842,380
10	Net (Increase) Decrease in Receivables	13,653,023	-15,306,466
11	Net (Increase) Decrease in Inventory	539,767	-6,714,633
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-5,534,463	11,916,674
14	Net (Increase) Decrease in Other Regulatory Assets	34,996,161	47,611,061
15	Net Increase (Decrease) in Other Regulatory Liabilities	11,513,932	10,225,050
16	(Less) Allowance for Other Funds Used During Construction	16,551,145	7,554,923
17	(Less) Undistributed Earnings from Subsidiary Companies	7,546,282	4,957,304
18	Other (provide details in footnote):	-41,492,468	-24,413,966
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	325,912,762	264,678,714
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-327,576,965	-246,539,337
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	10,675,095	5,397,871
31	Other (provide details in footnote):	25,390,083	2,381,759
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-312,861,977	-249,555,449
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		2,250,259
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-7,000,000	
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	333,525	922,056
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		1,514,798
53	Other (provide details in footnote):	-8,541,146	-1,266,217
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-310,987,306	-246,134,553
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	200,000,000	396,100,000
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):	50,000,000	20,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	250,000,000	416,100,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,063,636	-251,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,183,141	-6,921,974
77			
78	Net Decrease in Short-Term Debt (c)		-101,264,330
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-58,070,890	-56,910,568
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	187,682,333	-60,508
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	202,607,789	18,483,653
87			
88	Cash and Cash Equivalents at Beginning of Period	21,624,929	3,141,276
89			
90	Cash and Cash Equivalents at End of period	224,232,718	21,624,929

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

Amortization	Twelve Months Ended 12/31/10
Plant	6,834,579
Regulatory assets	2,002,795
Regulatory liability	(620,808)
Unamortized debt expense	2,368,760
Unamortized discount	289,995
Water rights	1,042,009
Other	202,855
	12,120,185

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

Cash paid during the period for:	
Income taxes	(57,768,090)
Interest (net of amount capitalized)	67,867,693

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

Cash Flow from Operating Activities (Other)	Twelve Months Ended 12/31/10
Pension and postretirement plan expense	14,727,814
Non-cash pension expense	(65,601,212)
Gain on sale of renewable energy certificates	(444,213)
Unbilled revenues	3,307,645
Other noncash adjustments to net income	217,365
Accrued interest	3,654,438
Payroll liabilities	1,297,584
Other assets and liabilities	1,348,111
	(41,492,468)

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	33,949,485

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

Other Cash Flows from Plant	Twelve Months Ended 12/31/10
Sale of utility property	18,982,212
Sale of emission allowances and renewable energy certificates	6,407,871
	25,390,083

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

Other Investing Cash Flows	Twelve Months Ended 12/31/10

FOOTNOTE DATA

Disbursements from rabbi trust	3,808,604
Net change in notes receivable from subsidiary	4,509,173
Proceeds from the sale of money market investment	263,567
Miscellaneous other investing activities	(40,198)
	8,541,146

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	24			(8,706,639)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				542,886
3	Preceding Quarter/Year to Date Changes in Fair Value	1,820,148			(1,923,082)
4	Total (lines 2 and 3)	1,820,148			(1,380,196)
5	Balance of Account 219 at End of Preceding Quarter/Year	1,820,172			(10,086,835)
6	Balance of Account 219 at Beginning of Current Year	1,820,172			(10,086,835)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				708,772
8	Current Quarter/Year to Date Changes in Fair Value	1,149,129			(3,158,753)
9	Total (lines 7 and 8)	1,149,129			(2,449,981)
10	Balance of Account 219 at End of Current Quarter/Year	2,969,301			(12,536,816)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(8,706,615)		
2			542,886		
3			(102,934)		
4			439,952	122,558,984	122,998,936
5			(8,266,663)		
6			(8,266,663)		
7			708,772		
8			(2,009,624)		
9			(1,300,852)	140,634,223	139,333,371
10			(9,567,515)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Idaho Power (IPC), a wholly-owned subsidiary of IDACORP, Inc., is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power. IERCO is accounted for using the equity method.

Basis of Reporting

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

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

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

Cash and Cash Equivalents

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

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Derivative Financial Instruments

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

Revenues

Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at period-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon relicensing project, as discussed in Note 3. 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 2.84 percent in 2010 and 2.81 percent in 2009.

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 2010 or 2009.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance, it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. Idaho Power's weighted-average monthly AFUDC rates for 2010 and 2009 were 8.0 percent and 6.7 percent, respectively. Idaho Power's reductions to interest expense for AFUDC were $11 million for 2010 and $5 million for 2009. Other income included $17 million and $8 million of AFUDC for 2010 and 2009, respectively.

Income Taxes

Idaho Power accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction over Idaho Power's Idaho service territory, Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impact currently for rate-making and financial reporting. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

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

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP).

The following table presents Idaho Power's accumulated other comprehensive loss balance at December 31 (net of tax):

	2010	2009
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 2,969	$ 1,820
Senior Management Security Plan	(12,537)	(10,087)
Total	$ (9,568)	$ (8,267)

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:

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

	2010	2009
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 46,199	$ 47,183
Advances for construction	7,061	8,335
Deferred compensation	21,045	20,661
Advanced payments	8,292	3,868
Tax credits	6,461	2,548
Retirement benefits	88,827	84,019
Other	4,422	5,236
Total	182,307	171,850
Deferred tax liabilities:		
Property, plant and equipment	284,794	282,034
Regulatory assets	422,216	382,136
Conservation programs	7,611	4,772
Power cost adjustment	11,833	34,025
Retirement benefits	93,997	65,690
Other	11,146	6,664
Total	831,597	775,321

Net deferred tax liabilities	$ 649,290	$ 603,471

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

	2010	2009
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 51,614	$ 54,296
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,641)	(1,735)
AFDC	(9,529)	(4,533)
Capitalized interest	3,674	1,529
Investment tax credits	(3,378)	(3,404)
Repair allowance	-	(3,500)
Removal costs	(2,850)	(3,810)
Capitalized overhead costs	(3,500)	(3,500)
Capitalized repair costs	(10,500)	-
Tax method change - uniform capitalization	(65,333)	-
Tax method change - repairs	(44,466)	-
Uncertain tax positions	74,436	1,138
Settlement of prior years tax returns	(1,138)	(4,119)
State income taxes, net of federal benefit	5,074	1,903
Depreciation	13,138	3,895
Other, net	2,233	(5,587)
Total income tax expense	$ 6,834	$ 32,573
Effective tax rate	4.6 %	21.0 %

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

	2010	2009
	(thousands of dollars)	
Income taxes currently payable (receivable):		
Federal	$ (62,068)	$ 19,732
State	(5,579)	2,385
Total	(67,647)	22,117
Income taxes deferred:		
Federal	6,752	18,993
State	(4,036)	(5,792)
Total	2,716	13,201
Uncertain tax positions:		
Federal	65,222	(2,496)
State	8,076	(485)
Total	73,298	(2,981)
Investment tax credits:		
Deferred	1,844	3,640
Restored	(3,377)	(3,404)
Total	(1,533)	236
Total income tax expense	$ 6,834	$ 32,573

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP.

Tax Credits Carryforwards
As of December 31, 2010, Idaho Power had 6.4 million of Idaho investment tax credit carryforward. The Idaho investment tax credit carryforward period expires from 2023 to 2024.

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):

	2010	2009
Balance at January 1,	$ 1,138	$ 4,119
Additions for tax positions of the current year	2,822	-
Additions for tax positions of prior years	71,614	1,138
Reductions for tax positions of prior years	(1,138)	(4,119)
Settlements with taxing authorities	-	-
Balance at December 31,	$ 74,436	$ 1,138

If recognized, the $74.4 million balance of unrecognized tax benefits at December 31, 2010 would affect the effective tax rate.

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Idaho Power recognized interest expense of $0.2 million in 2010, and a net reduction in interest expense of $0.2 million in 2009. As of December 31, 2010, Idaho Power had accrued interest of $0.2 million and none as of December 31, 2009. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions – U.S. federal and the State of Idaho. The open tax years are 2009-2010 for federal and 2007-2010 for Idaho. In May 2009, IDACORP and Idaho Power formally entered the Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. In January 2010, IDACORP was accepted into CAP for its 2010 tax year. With the exception of Idaho Power's capitalized repairs and uniform capitalization tax accounting methods (discussed below), IDACORP and Idaho Power believe there are no remaining tax uncertainties for the 2009 tax year and expect that the 2009 examination may conclude during fiscal year 2011.

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.

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. The estimated annual tax deduction related to capitalized repairs produces a net tax benefit of $9 million annually, which is approximately $5 million higher than Idaho Power's prior repair deduction method reported in 2009. The reversal of this temporary difference will offset a portion of the ongoing annual benefit.

Idaho Power's prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

The tax method is currently being audited under IDACORP's 2009 CAP examination and, on a national level, aspects of the method related to electric utility generation, transmission, and distribution property are the subject of an IRS Industry Issue Resolution program.

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. Since that time the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during the third quarter of 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. 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.

The resulting tax deductions available under the agreed upon uniform capitalization method are 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 current year tax expense from the reversal of this temporary difference. The prescribed regulatory accounting treatment for this method is the same as discussed earlier for the capitalized repairs method.

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. While Idaho Power has an agreement with the IRS for examination and tax return filing purposes, it is awaiting U.S. Congress Joint Committee on Taxation approval of its method or approval of methods filed by other similarly-situated companies under the IDD before concluding that the new method is effectively settled for financial reporting purposes.

Tax Impacts of Health Care Acts

As discussed further in Note 11, the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act were enacted in March 2010. As a result of this legislation, in the first quarter of 2010 Idaho Power reduced its deferred tax asset related to future Medicare Part D deductible retiree prescription drug expenses by $2.3 million, increased regulatory assets by $2.4 million, increased deferred tax liabilities by $1 million, and incurred a charge of $0.9 million.

3. REGULATORY MATTERS:

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, 2010	2009
Regulatory Assets:					
Income taxes		$ -	$ 429,457	$ 429,457	$ 389,910
Unfunded postretirement benefits (2)		-	182,742	182,742	168,026
Pension expense deferrals (3)		53,169	10,664	63,833	39,251
Energy efficiency program costs (3)		19,467	-	19,467	12,207
Power supply costs (3)	Varies	29,753	-	29,753	84,633
Fixed cost adjustment (3)	Varies	12,340	-	12,340	7,836

Asset retirement obligations (4)		-	15,372	15,372	14,749
Mark-to-market liabilities (5)		-	2,278	2,278	280
Other	2011-2015	204	5,980	6,184	3,789
Total (6)		$ 114,933	$ 646,493	$ 761,426	$ 720,681
Regulatory Liabilities:					
Income taxes		$ -	$ 53,440	$ 53,440	$ 54,958
Removal costs (4)		-	157,642	157,642	155,405
Investment tax credits		-	71,972	71,972	73,506
Deferred revenue-AFUDC		13,258	7,953	21,211	9,894
Mark-to-market assets (5)		-	573	573	715
Other	2011	787	7,721	8,508	1,579
Total (7)		$ 14,045	$ 299,301	$ 313,346	$ 296,057

(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 below.

(4) Asset retirement obligations and removal costs are discussed in Note 13.

(5) Mark-to-market assets and liabilities are discussed in Note 16.

(6) Includes \$2,240 and \$601 for 2010 and 2009, respectively, reported in other current assets on the balance sheets.

(7) Includes \$8,011 and \$8,972 for 2010 and 2009, respectively, reported in other current liabilities on the balance sheets.

The majority of Idaho Power's regulatory assets and liabilities are reflected in customer rates and 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.

Deferred Net Power Supply Costs

Deferred power supply costs are recorded as a deferred charge on the balance sheets for future recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates. This difference in net power supply costs primarily results from changes in short-term wholesale market prices and sales and purchase volumes, the level of hydroelectric generation, the level of thermal generation, and retail loads. Changes in deferred power supply costs over the last two years were as follows:

	Idaho	Oregon(1)	Total
Balance at January 1, 2009	$ 140,821	$ 8,278	$ 149,099
Costs deferred through PCA and PCAM	42,533	(184)	42,349
Prior costs expensed and recovered through rates	(113,134)	(2,283)	(115,417)
SO_2 allowances credited to account	(2,034)	(83)	(2,117)
Interest and other	3,226	1,135	4,361
2007 Excess power costs order	-	6,358	6,358
Balance at December 31, 2009	$ 71,412	$ 13,221	$ 84,633
Costs deferred through PCA and PCAM	14,324	-	14,324
Prior costs expensed and recovered through rates	(63,757)	(1,792)	(65,549)
SO_2 allowances credited to account	(4,504)	79	(4,425)

Interest and other	84	686	770
Balance at December 31, 2010	$ 17,559	$ 12,194	$ 29,753

(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 $2 million). Deferrals are amortized sequentially.

Idaho Jurisdiction Power Cost Adjustment Mechanism:

In the Idaho jurisdiction, Idaho Power has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks 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 currently being recovered in retail rates. The annual PCA adjustments are based on two components:

- 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
- a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. This 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 true-up component is calculated monthly, and interest is applied to the balance.

The following table summarizes PCA rate adjustments in the three years ended December 31, 2009, and 2010:

Effective Date	$ Change (millions)	Notes
June 1, 2010	$(146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below in "Idaho 2009 Settlement Agreement and 2010 PCA Order."
June 1, 2009	$84.3	The increase was net of $4.5 million of gains from sales of excess SO_2 emission allowances which the IPUC ordered be applied against the PCA. The IPUC has allowed Idaho Power to retain its PCA sharing percentage of the gain from sales of excess SO_2 emission allowances as a shareholder benefit with the remainder recorded as a customer benefit, substantially all of which was used to reduce the PCA. Proceeds from the sale of renewable energy certificates (RECs) will also be used to reduce the PCA. RECs are acquired by Idaho Power through purchases of renewable energy.

In its order approving Idaho Power's 2008-2009 PCA, the IPUC directed Idaho Power to set up workshops with the IPUC Staff and several of Idaho Power's largest customers to address issues not resolved in that PCA filing. The workshops resulted in the following changes to the PCA mechanism:

- PCA sharing ratio – the PCA allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10;
- LGAR – the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. The stipulation agreed on a new formula for calculating the LGAR. Based on the final rates approved by the IPUC, as of the date of this report the LGAR is $26.63 per MWh;
- use of Idaho Power's operation plan power supply cost forecast – the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year's "true-up" rate, beginning with the 2009-2010 PCA filing;

- inclusion of third-party transmission expense – transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these costs from levels included in base rates is now reflected in PCA computations; and
- adjusted distribution of base net power supply costs – base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

In the IPUC's May 2010 order implementing new PCA rates for the period from June 1, 2010 to May 31, 2011, the IPUC identified the use of the LGAR in times of load decline as an issue of contention. However, the IPUC Staff recommended no change to the load growth adjustment amounts or methodology, and the IPUC did not remove the LGAR adjustment to the PCA component. The IPUC's order stated, however, that it expects the IPUC Staff, Idaho Power, and interested parties to meet to address an appropriate change to the LGAR mechanism to eliminate a potential double recovery when loads decline. On January 14, 2011, Idaho Power submitted to the IPUC comments in support of a revised methodology that was submitted for consideration by another utility. Idaho Power's filing with the IPUC requested a new LGAR rate of $19.36 per MWh under the revised methodology effective April 1, 2011. As of the date of this report, a determination and order from the IPUC is pending.

Oregon Jurisdiction Power Cost Adjustment Mechanism:

Idaho Power's power cost recovery mechanism in Oregon went into effect in 2008. It has two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows Idaho Power to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

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 APCU has two components: the "October Update," Idaho Power's calculation of estimated normalized net power supply expenses for the following April through March test period, and the "March Forecast," Idaho Power's forecast of expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices.
Base power supply cost changes since inception are as follows:

Year	APCU Description
2011	Idaho Power's October Update portion of the 2011 APCU indicates that revenues associated with Idaho Power's base net power supply costs would be increased by $1.6 million over the current rates. The actual impact will be determined once the March Forecast portion is filed in March 2011 and combined with the October Update. Final rates are expected to become effective on June 1, 2011.
2010	A rate increase of $2.6 million annually took effect June 1, 2010.
2009	A rate increase of $3.9 million annually took effect June 1, 2009

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 it results in Idaho Power's actual return on equity (ROE) for the year being no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that it results in Idaho Power's actual ROE for that year being no less than 100 basis points above Idaho Power's last authorized ROE. Results of the PCAM since inception are as follows:

Year	PCAM Description
2010	Actual net power supply costs were within the deadband, resulting in no deferral.
2009	Actual net power supply costs were within the deadband, resulting in no deferral.

Oregon Excess Power Cost Deferrals:

In May 2009, the OPUC adopted a stipulation allowing Idaho Power to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for the period May 1 through December 31, 2007. Idaho Power recorded the $6.4 million deferral in the second quarter of 2009 as a reduction to power cost adjustment expense. The amount to be recovered was reduced by $0.9 million of previously deferred SO_2emission allowance sales (including interest) during the same period. Effective January 2011, these costs are being collected through rates and amortized.

Fixed Cost Adjustment Mechanism (FCA)

The FCA mechanism began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2009. The FCA is a rate mechanism designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. On April 29, 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactively to January 1, 2010.

On May 29, 2010, the IPUC approved the recovery of $6.3 million of under-recovered fixed costs related to 2009, with rates effective June 1, 2010 through May 31, 2010. In May 2009, the IPUC approved FCA rates effective June 1, 2009 through May 31, 2010, to recover $2.7 million of fixed costs under-recovered during 2008

Idaho Rate Cases

Idaho 2009 Settlement Agreement and 2010 PCA Order: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power's customers, the IPUC Staff, and others. Significant elements of the settlement agreement include:

- a general rate moratorium in effect until January 1, 2012. The moratorium does not apply to other specified revenue requirement proceedings, such as the PCA, the FCA, pension funding, advanced metering infrastructure (AMI), energy efficiency rider, and government imposed fees;
- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change. This provision anticipated a significant reduction in PCA rates for the 2010-2011 PCA year;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the accelerated amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's actual rate of return on equity is below 9.5 percent in any calendar year from 2009 to 2011 in its Idaho jurisdiction. Idaho Power would be permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more that $15 million in any one year unless there is a carryover. Carryover amounts are added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

Because Idaho Power's Idaho-jurisdiction return on equity was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and accelerated amortization provisions were not triggered. In accordance with the settlement, Idaho Power has available $25 million of additional ADITC amortization for use in 2011.

On April 15, 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. On May 28, 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million. The net effect of these two rate adjustments was an overall decrease in customer rates of $58.2 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Idaho 2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent, and an overall rate of return of 8.18 percent. On February 19, 2009, Idaho Power filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased Idaho Power's Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed Idaho Power to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on Idaho Power's net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

The IPUC denied reconsideration with respect to a refund of $3.3 million of fees recovered by Idaho Power from the FERC. On April 2, 2009, Idaho Power filed an application with the IPUC for an accounting order approving amortization of the fees over a five-year period beginning October 2006 when Idaho Power received the FERC credit. The IPUC approved Idaho Power's requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, Idaho Power recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period, September 2011. As the regulatory liability is amortized it reduces electric utility other operations expense ratably over the remaining amortization period.

Retirement Benefits Plan: Idaho Power defers its pension expense as a regulatory asset. Idaho Power deferred approximately $24 million and $29 million, of pension expense to a regulatory asset in 2010 and 2009, respectively. Deferred pension costs are expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. Idaho Power only records a carrying charge recorded on the unrecovered balance of cash contributions.

In May 2010, the IPUC approved Idaho Power's request to increase rates to allow recovery of Idaho Power's 2009 cash contribution to its defined benefit pension plan, which contribution was made in September 2010. Idaho Power's application sought approval of $5.4 million in pension cost recovery over a one-year period to allow recovery contemporaneous with Idaho Power's expected cash contributions to the plan. In the IPUC's May 2010 order approving an increase in rates to allow recovery of $5.4 million of Idaho Power's $60 million contribution made in September 2010 to the defined benefit pension plan, the IPUC stated that "Idaho Power is advised that, previous orders notwithstanding, approval of Idaho Power's pension contributions in this case does not guarantee IPUC approval of future pension plan contributions. Authority for the balancing account and regulatory account remain in place. However, further justification is required before additional rate recovery for future contributions will be authorized."

Following the issuance of the IPUC's order, Idaho Power undertook its annual review of its current retirement benefits packages, which included a thorough review of costs, benefits, and risks associated with the retirement benefits package, and considered alternatives to its pension plan and the weighting of plans between defined benefit and defined contribution. Following that analysis, in September 2010 Idaho Power revised the defined benefit plan for persons hired on or after January 1, 2011 to reduce the company's estimated cost of the plan for those employees by 20 percent. On October 1, 2010, Idaho Power filed an application with the IPUC requesting an order accepting Idaho Power's 2011 retirement benefits package on or before February 28, 2011. On December 14, 2010, the IPUC Staff and the Industrial Customers of Idaho Power (ICIP) filed comments with the IPUC recommending that the IPUC reject Idaho Power's request for acceptance of its 2011 retirement benefits package evaluation. The IPUC Staff stated in its comments to the IPUC that, among other items, it believed Idaho Power did not adequately consider available alternatives. On December 28, 2010, Idaho Power filed with the IPUC reply comments to the IPUC Staff's and ICIP's comments. In its reply comments, Idaho Power noted that based on its analysis it has set its 2011 retirement benefits package at a competitive cost level that is less than the median offerings of similarly situated utility peers, has carefully considered the allocation of costs and investment risk between customers and employees, and the operational imperative to maintain safe, reliable service with an engaged, qualified, experienced, and flexible workforce, and thus requested anew that the IPUC issue an order accepting Idaho Power's 2011 retirement benefits package. On January 26, 2011, the IPUC issued an order stating that Idaho Power is not precluded from filing for recovery of 2010 contributions before proceedings relating to the 2011 retirement benefits package prudency have concluded.

Idaho Energy Efficiency Rider: On March 16, 2010, Idaho Power filed an application with the IPUC requesting an order designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred expenses. On November

16, 2010, the IPUC issued an order designating all $50.7 million of energy efficiency expenditures as prudently incurred and approved for ratemaking purposes. Idaho Power's 2010 expenditures for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions totaled $44.2 million.

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

Oregon Rate Cases

Oregon 2009 General Rate Case: On February 24, 2010, the OPUC approved a $5 million, or 15.4 percent, increase in base rates in the Oregon jurisdiction. The new rates were effective March 1, 2010, and are based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. Idaho Power's previously authorized rate of return in Oregon was 7.83 percent and its requested rate of return in the general rate case filing was 8.68 percent.

Other Regulatory Proceedings

Advanced Metering Infrastructure: The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense.

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

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI through the then-current date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded in 2010 and 2009 were $10.6 million and $6.2 million, respectively.

On March 15, 2010, Idaho Power filed an application with the IPUC requesting authority to implement a $2.4 million base rate increase for identified customer classes to recover costs relating to the AMI project. On May 28, 2010, the IPUC approved Idaho Power's application, authorizing the rate increase effective June 1, 2010.

In the Oregon jurisdiction, the OPUC approved accelerated depreciation and recovery of existing meters located in Oregon over an 18-month period beginning January 2009. Idaho Power has substantially completed the deployment of the Oregon service-territory meters. The existing meters were fully depreciated prior to their removal from service. The approval increased both rates and depreciation expense $0.8 million in 2009 and $0.4 million in 2010.

Depreciation Filings: In 2008 and 2009 Idaho Power filed revisions to its depreciation rates with the IPUC, the OPUC, and the FERC. The commissions approved the new rates, which reduce depreciation expense approximately $8.5 million annually. Idaho Power began applying the new depreciation rates in August 2008.

Federal Regulatory Matters

Open Access Transmission Tariff (OATT) Rates: In 2006, Idaho Power moved from a fixed rate to a formula rate for its OATT, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. On August 28, 2009, Idaho Power filed its annual informational filing with the FERC that contains the annual update of the formula rate based on the 2008 test year. The new rate included in the filing was $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. The rates were effective from October 1, 2009 through September 30, 2010. On August 26, 2010, Idaho Power submitted its annual information filing for its OATT to FERC. The new rate submitted by Idaho Power was $19.60 per kW/year and was effective as of October 1, 2010 for a period of one year. For the years ended December 31, 2009 and 2010, revenues from the transmission rate for service under the OATT were $13.3 million and $15.4 million, respectively. 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 refunds, including interest, to transmission customers of $0.5 million.

***FERC OATT Proceedings and ITSA Amendment*:** On May 24, 2010, Idaho Power and PacifiCorp entered into and filed an offer of settlement with the FERC in connection with Idaho Power's request for authority to increase rates to PacifiCorp under the existing Agreement for Interconnection and Transmission Services (ITSA). Under the settlement, which the FERC approved in July 2010, PacifiCorp will take and pay for 250 MW of long-term firm point-to-point transmission service, pursuant to the ITSA, the rates, terms, and conditions of which will be equivalent to Idaho Power's OATT. For the twelve months ended December 31, 2010, Idaho Power collected $4.2 million related to the ITSA with PacifiCorp.

***FERC Transmission Rate Refunds and Shortfall Filing*:** On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund $13.3 million to these customers. Based on the FERC order, Idaho Power reserved an additional $7.9 million (including $0.7 million of interest) in 2008 to bring its reserve to the $13.3 million ordered refunded. Idaho Power made the refunds in February 2009 and filed a request for rehearing with the FERC. Of the additional $7.9 million ordered refunded, $2.3 million related to transmission revenues recorded in 2007 and $1.7 million related to transmission revenues recorded in 2006. In March 2009, the FERC issued a tolling order that effectively relieved it from acting for an indefinite period of time on Idaho Power's request for rehearing.

For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to Idaho Power's overall revenue requirement. In the last two general rate cases, Idaho Power included an estimate of OATT revenues from third parties based on the forecasted OATT rate. However, the FERC order issued on January 15, 2009 reduced actual third-party transmission revenues Idaho Power received starting in June 2006, resulting in an overstatement of the revenue credits in the Idaho jurisdictional revenue requirement.

On October 30, 2009, the IPUC approved Idaho Power's request for authorization to defer the difference between the revenue credits in the last two general rate cases and the amount of OATT revenues Idaho Power has received since March 2008 and expected to receive through May 2010. The IPUC order authorized Idaho Power to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning January 1, 2011 and did not authorize a carrying charge on the balance. Based on actual and projected transmission revenues from March 2008 through May 2010, Idaho Power recorded a $4.7 million regulatory asset in 2009 for potential future recovery.

On October 13, 2010, Idaho Power refreshed its filing with the IPUC for its deferral related to unrecovered transmission revenues. Termination of a transmission arrangement with PacifiCorp and adjustments to other transmission arrangements allowed Idaho Power to reduce its prior deferral amount to $2.1 million. Idaho Power requested to begin amortization of the $2.1 million deferred amount on January 1, 2012, rather than January 1, 2011, as originally ordered, because Idaho Power's settlement agreement would not permit potential inclusion of the deferral amount in rates until after January 1, 2012. On February 9, 2011, the IPUC issued an order reducing the deferral amount to $2.1 million, as requested by Idaho Power, but denied the request to begin amortization on January 1, 2012, instead ordering that Idaho Power advise the IPUC when the FERC has issued its order on rehearing. Thereafter, Idaho Power may request a commencement date for the three-year amortization period.

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31:

	2010	2009
	(thousands of dollars)	
First mortgage bonds:		
6.60% Series due 2011	$ 120,000	$ 120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	-
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	-
Total first mortgage bonds	1,415,000	1,215,000
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	7,446	8,509
Unamortized discount - net	(3,440)	(3,060)
Total Idaho Power outstanding debt(2)	$ 1,609,351	$ 1,410,794

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2010, to $1.581 billion.

(2) At December 31, 2010 and 2009, the overall effective cost of Idaho Power's outstanding debt was 5.53 percent and 5.76 percent, respectively.

At December 31, 2010, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2011	2012	2013	2014	2015	Thereafter
Idaho Power	$ 121,064	$ 101,064	$ 71,064	$ 1,064	$ 1,064	$ 1,317,471

Idaho Power Long-Term Financing
In May 2010, Idaho Power registered with the SEC the sale 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. On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement. As of December 31, 2010, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

Mortgage: As of December 31, 2010, 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 $407 million of additional first mortgage bonds based on total unfunded property additions of approximately $679 million. Idaho Power could issue an additional $612 million of first mortgage bonds based on retired first mortgage bonds. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

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

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

5. NOTES PAYABLE:

Idaho Power has a $300 million credit facility that expires on April 25, 2012. Commercial paper may be issued up to the amounts supported by the credit facilities. Under these facilities the companies pay a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's Investors Service and Standard & Poor's Ratings Services. At December 31, 2010, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness.

At December 31, 2010, no loans were outstanding on Idaho Power's facilities. A summary of notes payable is presented below:

	2010	2009
	(thousands of dollars)	
Balances:		
At the end of year	$ -	$ -
Average during the year	$ 348	$ 46,386
Weighted-average interest rate:		
At the end of year	-	-

6. COMMON STOCK:

Idaho Power Common Stock

In 2010 and 2009, IDACORP contributed $50 million and $20 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued.

Dividend Restrictions

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 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 are limited to the extent payment of such dividends would violate the covenant or Idaho Power's Code of Conduct. At December 31, 2010, the leverage ratio for Idaho Power was 53 percent. Based on these restrictions, Idaho Power's dividends were limited to $538 million, at December 31, 2010. There are additional covenants, subject to exceptions, that prohibit or restrict certain investments or acquisitions, mergers, or sale or disposition of property without consent; the creation of certain liens; and any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2010, Idaho Power was in compliance with all facility covenants.

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.

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

7. STOCK-BASED COMPENSATION:

Through its parent company IDACORP, Idaho Power has three share-based compensation plans. The employee plans are 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 long-term growth. There is also one non-employee plan, the Non-Employee Directors Stock Compensation Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based compensation. The DSP was terminated for purposes of new awards effective February 26, 2010, and grants to nonemployee directors subsequent to that date have been made pursuant to the LTICP.

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, 2010, the maximum number of shares available under the LTICP and RSP were 1,537,639 and 16,064, respectively.

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

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued and paid out only on shares that eventually vest.

The performance awards are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

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

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2010	286,035	$ 24.49
Shares granted	139,780	31.39
Shares forfeited	(41,026)	19.40
Shares vested	(55,288)	34.64
Nonvested shares at December 31, 2010	329,501	$ 26.35

The total fair value of shares vested during the years ended December 31, 2010 and 2009, was $3.3 million and $3.9 million, respectively. At December 31, 2010, Idaho Power had $3.2 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 1.65 years. Idaho Power uses IDACORP's original issue and/or treasury shares for these awards.

In 2010, a total of 14,982 shares were awarded to directors at a grant date fair value of $33.03 per share. Directors elected to defer receipt of 8,172 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, 2010, all compensation costs related to stock options has been recognized. Idaho Power uses IDACORP's original issue and/or treasury shares to satisfy exercised options. The following table presents information about options vested and exercised (in thousands of dollars):

	2010	2009
Fair value of options vested	$ 96	$ 208
Intrinsic value of options exercised	1,475	204
Cash received from exercises	5,394	591
Tax benefits realized from exercises	577	80

Idaho Power's stock option transactions are summarized below:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2009	413,964	$ 33.31	2.96	$ 862
Exercised	(182,572)	27.78		
Expired	(28,758)	35.01		
Outstanding at December 31, 2010	202,634	$ 38.05	1.13	$ 314
Vested and exercisable at December 31, 2010	202,634	$ 38.05	1.13	$ 314

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

	2010	2009
Compensation cost	$ 3,489	$ 3,986
Income tax benefit	$ 1,364	$ 1,587

No equity compensation costs have been capitalized.

8. COMMITMENTS:

Purchase Obligations

At December 31, 2010, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel:

	2011	2012	2013	2014	2015	Thereafter
			(thousands of dollars)			
Cogeneration and power production	$ 237,339	$ 156,696	$ 204,437	$ 217,247	$ 247,371	$ 4,681,321
Power and transmission rights	35,900	11,594	5,017	3,800	3,726	7,559
Fuel	79,602	68,047	68,365	68,311	22,113	100,172

As of December 31, 2010, Idaho Power had signed agreements to purchase energy from 126 CSPP facilities with contracts ranging from one to 35 years. Ninety-one of these facilities, with a combined nameplate capacity of 491 MW, were on-line at the end of 2010; the other 35 facilities under contract, with a combined nameplate capacity of 697 MW, are projected to come on-line by year end 2014. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2010, Idaho Power purchased 910,429 megawatt-hours (MWh) from these projects at a cost of $55 million, resulting in a blended price of $60.38 per MWh and 970,419 MWh at a cost of $59 million in 2009.

In addition, Idaho Power has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees.

	2011	2012	2013	2014	2015	Thereafter
			(thousands of dollars)			
Operating leases	$ 3,509	$ 2,139	$ 2,047	$ 1,988	$ 2,029	$ 15,740
Equipment, maintenance, and service agreements	53,735	15,724	10,356	6,291	6,083	6,465
FERC and other industry-related fees	8,514	7,575	7,527	5,222	5,114	25,647

Idaho Power's expense for operating leases was approximately $3.3 million in 2010 and $3.4 million in 2009.

Guarantees

Idaho Power has agreed to guarantee the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2010. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. BCC continually 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. 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 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 indemnifications cannot be reasonably estimated. Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2010, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

9. CONTINGENCIES:

Legal Proceedings

Western Energy Proceedings at the FERC:

In this report, the term "western energy situation" is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices, and blackouts in the western United States. High prices for electricity 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 (referred to in this report as the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are more than 200 petitions pending in the Ninth Circuit for review of numerous FERC orders regarding the western energy situation. Decisions in these appeals may have implications with respect to other pending cases, including those to which Idaho Power or IE are parties. Idaho Power and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters. Except as to the matters described below under "Pacific Northwest Refund," Idaho Power and IE believe that settlement releases they have obtained that are described below under "California Refund" and "Market Manipulation" will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and that these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

California Refund: This proceeding originated with an effort by agencies of the State of California and investor-owned utilities in

California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. The FERC has issued numerous orders establishing price mitigation plans for sales in the California wholesale electricity market, including the methodology for determining refunds. IE and numerous other parties have petitioned the Ninth Circuit for review of the FERC's orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed before the Ninth Circuit, which from time to time has identified discrete cases that can proceed to briefing and decision while it stayed action on the other consolidated cases.

On May 22, 2006, the FERC approved an Offer of Settlement between and among IE and Idaho Power, the California Parties (consisting of Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources (CDWR), and the California Attorney General) and additional parties that elected to be bound by the settlement. The settlement disposed of matters encompassed by the California refund proceeding, as well as market manipulation claims and investigations relating to the western energy situation among and between the parties agreeing to be bound by it. Although many market participants agreed to be bound by the settlement, other market participants, representing a small minority of potential refund claims, initially elected not to be bound by the settlement. From time to time, as the California Parties have reached settlements with those other market participants, they have elected to opt into the IE-Idaho Power-California Parties' settlement. The settlement provided for approximately $23.7 million of IE's and Idaho Power's estimated $36 million rights to accounts receivable from the California Independent System Operator (Cal ISO) and the California Power Exchange (CalPX) to be assigned to an escrow account for refunds and for an additional $1.5 million of accounts receivable to be retained by the CalPX until the conclusion of the litigation. The additional $1.5 million of accounts receivable retained by the CalPX is available to fund the claims of non-settling parties if they prevail in the remaining litigation of the California refund proceeding and the balance in the escrow account is insufficient, after distribution to settling parties, to satisfy the claims of the litigants. Any additional amounts owed to non-settling parties would be funded by other amounts owed to IE and Idaho Power by the Cal ISO and CalPX, or directly by IE and Idaho Power, and any excess funds remaining in the escrow and the amounts retained by the CalPX at the end of the case would be returned to IE and Idaho Power. The remaining IE and Idaho Power receivables were paid to IE and Idaho Power under the settlement.

In an August 2006 decision, the Ninth Circuit ruled that all transactions that occurred within the CalPX and the Cal ISO markets from October 2, 2000 to June 21, 2001 were proper subjects of the refund proceeding. In that decision the Ninth Circuit refused to expand the proceedings into the bilateral market, required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date, and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. Parts of the decision exposed sellers to increased claims for potential refunds. The Ninth Circuit issued its mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court's decision.

On November 19, 2009, the FERC issued an order to implement the Ninth Circuit's remand. The remand order established a trial-type hearing in which participants will be permitted to submit information regarding (i) specified tariff violations committed by any public utility seller from January 1, 2000 to October 2, 2000 resulting in a transaction that set a market clearing price for the trading period when the violation occurred, and (ii) claims for refunds for multi-day transactions and energy exchange transactions entered into during the refund period (October 2, 2000 to June 21, 2001). Numerous parties, including IE and Idaho Power, filed motions to clarify the FERC's order and responses to these motions. In response to a solicitation from the FERC, on September 22, 2010, IE and Idaho Power, along with a number of other parties, submitted comments to the FERC regarding the scope of the proceedings. Although IE and Idaho Power are unable to predict when or how the FERC will rule on these motions and the later comments, the effect of the remand order for IE and Idaho Power is confined to the minority of market participants that are not bound by the IE-Idaho Power-California Parties' settlement described above. IE and Idaho Power believe the remanded proceedings will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and Idaho Power made such a cost filing, which was rejected by the FERC. On June 18, 2009, FERC issued an order stating that it was not ruling on IE's and Idaho Power's request for rehearing of the cost filing rejection because their request had been withdrawn in connection with the IE-Idaho Power-California Parties' settlement. On July 8, 2009, IE and Idaho Power sought further rehearing at the FERC because their withdrawal pertained only to the parties with whom IE and Idaho Power had settled. On June 18, 2009, in a separate order, the FERC ruled that only net refund recipients were responsible for the costs associated with cost filings. While most net refund recipients are bound by the settlement, until the Cal ISO completes its refund calculations it is uncertain whether there are any net refund recipients who are not bound by the settlement. If there are no such parties, then IE's and Idaho Power's request for rehearing will be moot. On May 18, 2010, the FERC denied rehearing. On June 25, 2010, IE and Idaho Power filed a petition for review of the pertinent FERC orders in the Ninth Circuit. Until the Cal ISO completes its refund calculations, it is uncertain whether there are any parties who are not bound by the California refund settlement that might be affected by the cost filing and the review of its rejection. IE and Idaho Power are unable to predict how or when the Cal ISO's refund calculations will be completed and how or when the Ninth Circuit might rule, but the direct effect of any such calculations and ruling is confined to obligations of IE and Idaho Power to the small minority of claims of market participants that are not bound by the settlement. Accordingly, IE and Idaho Power believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Market Manipulation: On June 25, 2003, the FERC ordered approximately 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including Idaho Power, to show cause why certain trading practices did not constitute gaming or other forms of proscribed market behavior in concert with another party (partnership) in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the partnership show cause proceeding against Idaho Power. Later in 2004, the FERC approved a settlement of the gaming proceeding without finding of wrongdoing by Idaho Power.

The orders establishing the scope of the show cause proceedings are the subject of review petitions in the Ninth Circuit. Between August and late November 2010, at the request of IE and Idaho Power, all 12 parties that filed petitions for review of the FERC's orders establishing the scope of the show cause proceedings filed to withdraw their petitions solely as they relate to IE and Idaho Power. The Ninth Circuit granted all the motions to withdraw during September through December 2010, dismissing with prejudice these review proceedings as they pertain to IE and Idaho Power.

On June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000 through October 1, 2000, but the FERC terminated its investigations as to Idaho Power on May 12, 2004. California government agencies and California investor-owned utilities appealed the FERC's termination of this investigation as to Idaho Power and more than 30 other market participants. On August 12, 2010, in response to a request by IE and Idaho Power, the California government agencies and California investor-owned utilities filed a request to withdraw their petitions for review solely as they relate to IE and Idaho Power. The Ninth Circuit granted the motion in September 2010 dismissing these review proceedings with prejudice as they pertain to IE and Idaho Power.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in *Port of Seattle, Washington v. FERC*, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales originating in the Pacific Northwest to the CDWR in the scope of proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On September 4, 2009, IE and Idaho Power joined with a number of other parties in a joint petition for a writ of certiorari to the U.S. Supreme Court, which was denied on January 11, 2010.

In several separate filings, the California Parties - which no longer include the California Electricity Oversight Board - and the City of Tacoma, Washington (Tacoma) and the Port of Seattle, Washington (Port of Seattle) asked the FERC to reorganize and restructure the case in different ways to enable them to pursue claims, as asserted by the California Parties, that all spot market sales in the Cal ISO and CalPX markets and sales to CDWR made in the Pacific Northwest, and, as asserted by Tacoma and Port of Seattle, other sales in the Pacific Northwest, from January 1, 2000 through June 20, 2001, should be subject to refund and repriced, because market manipulation and tariff violations affected spot market prices. Their requests would expand the scope of the refund period in the Pacific Northwest proceeding from the December 25, 2000 through June 20, 2001 period previously considered by the FERC. On May 22, 2009, the California Parties filed a motion with the FERC to sever claims regarding sales originating in the Pacific Northwest to CDWR from the remainder of the Pacific Northwest proceedings and to consolidate their claims regarding these sales with ongoing proceedings in cases that IE and Idaho Power have settled, as well as with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled (Brown Complaint). IE and Idaho Power, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed responses to the motion of the California Parties. Tacoma and the Port of Seattle jointly filed a motion on August 4, 2009 with the FERC in connection with the California refund proceeding, the *Lockyer* remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and Idaho Power previously were dismissed), the Brown Complaint, and the Pacific Northwest refund remand proceeding. The Tacoma and the Port of Seattle motion asks the FERC to require refunds from all sellers in the Pacific Northwest spot markets for the expanded period (January 1, 2000 through June 20, 2001). IE and Idaho Power joined with a number of other sellers in the Pacific Northwest markets during 2000 and 2001 in opposing the motion of Tacoma and the Port of Seattle. On April 19, 2010, the California Parties filed a motion with the FERC renewing the requests contained in their May 22, 2009 motion and on May 3, 2010, IE and Idaho Power joined with a number of other parties opposing the renewal request. On July 21, 2010, the Port of Seattle and Tacoma once again filed a motion requesting that the FERC either summarily dispose of the case or set it for hearing, and the California Parties, answering a pleading in the Brown Complaint, renewed their request for consolidation. The FERC has not acted on the Ninth Circuit remand or the motions.

IE and Idaho Power intend to vigorously defend their positions in these proceedings but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations, or cash flows.

Sierra Club Lawsuit and EPA Notice of Violation – Boardman:

In September 2008, the Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit and Clean Air Act (CAA) violations at the Boardman coal-fired plant located in Morrow County, Oregon. The complaint sought, in addition to injunctive remedies, civil penalties of up to $32,500 per day per violation, and reimbursement of plaintiffs' costs of litigation, including reasonable attorneys' fees. Idaho Power is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent of the plant and is the operator of the plant.

In September 2010, the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation to PGE, alleging that PGE has violated the New Source Performance Standards (NSPS) and operating permit requirements under the CAA, as a result of modifications made to the plant in 1998 and 2004. The Notice of Violation states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but does not impose any penalties, or specify the amount of any proposed penalties with respect to the alleged violations.

Idaho Power continues to monitor the status of these matters but is unable to predict their outcome or what effect these matters may have on its consolidated financial position, results of operations, or cash flows.

Water Rights - Snake River Basin Adjudication:

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses.

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

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water right 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 right 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 Resources 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 is currently working with the Board, other stakeholders, and the Legislature in implementing the provisions of the CAMP management plan.

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

U.S. Bureau of Reclamation Proceedings:

Idaho Power filed a complaint on October 15, 2007, and an amended complaint on September 30, 2008, in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation (USBR). The complaint relates to a 1923 spaceholder contract right for storage and delivery of water to Idaho Power from American Falls Reservoir, a USBR storage reservoir on the Snake River. In the complaint, Idaho Power alleges that the USBR breached the contract by the failure to recognize certain secondary storage rights referenced in the contract and claims damages for the lost generation resulting from the reduced flows downstream of the Reservoir, and asks for a prospective declaration of the rights and obligations of the parties under the 1923 contract. The USBR claims that the 1923 contract was abrogated or amended by the 1976 rebuild of American Falls Reservoir and that the secondary storage provisions of the 1923 contract no longer apply. The water rights for, and the operation of, American Falls Reservoir are also the subject of litigation in the SRBA, described above. Idaho Power has been working with the USBR and Idaho interests (including the State of Idaho and upstream water users) in an effort to resolve the contested contract issues that are common to both the SRBA and the pending federal case with the USBR. These efforts are focused on a recognition in state policy and the Idaho water plan that will promote more efficient operation of the upper Snake River reservoir system to optimize the use of Snake River flows for hydroelectric generation downstream while recognizing and protecting in-reservoir spaceholder contract rights. In an effort to promote judicial efficiency, the parties agreed to stay the pending federal case and present certain legal issues associated with the 1923 contract to the court in the SRBA case, the resolution of which are expected to resolve issues in the pending federal case. These issues were presented to the SRBA court through motions for summary judgment, which were argued in December 2010. However, as the parties continue to pursue a negotiated resolution to the 1923 contract issues, they have requested that the SRBA withhold any ruling on the motions pending the outcome of ongoing settlement negotiations. Idaho Power is unable to predict the outcome of this matter or what effect it may have on its financial position, results of operations, or cash flows.

Oregon Trail Heights Fire:

On August 25, 2008, a fire ignited beneath an Idaho Power distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes, and damage or alleged fire-related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of Idaho Power's distribution poles and that high winds contributed to the fire and its resultant damage. Idaho Power received notices of claims from a number of the homeowners and their insurers and has reached settlements with most of the individuals or their insurers who have alleged damages resulting from the fire. Idaho Power is insured up to policy limits against liability for claims in excess of its self-insured retention, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations, or cash flows.

Other Legal Proceedings:

From time to time Idaho Power is party to legal claims, actions, and proceedings in addition to those discussed above. Resolution of any of these matters will take time and the companies cannot predict the outcome of any of these proceedings. The companies currently believe that resolution of these matters will not have a material adverse effect on Idaho Power's financial position, results of operations, or cash flows.

10. BENEFIT PLANS:

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. Idaho Power's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In September 2010, Idaho Power contributed $60 million to its defined benefit pension plan. The contribution was in excess of the $6 million minimum contribution required to be made in 2010 for the 2009 plan year. Idaho Power elected to contribute more than the minimum requirement in order to bring the plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. Idaho Power was not required to contribute to the plan in 2009 or 2008. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2010 and 2009, approximately $46.2 million and $40.3 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		SMSP	
	2010	2009	2010	2009
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 506,744	$ 464,416	$ 52,719	$ 48,393
Service cost	17,671	16,514	1,541	1,610
Interest cost	29,119	27,865	3,004	2,854
Actuarial loss	35,909	16,193	5,186	3,156
Benefits paid	(19,509)	(18,244)	(3,324)	(3,294)
Benefit obligation at December 31	569,934	506,744	59,126	52,719
Change in plan assets:				
Fair value at January 1	313,474	295,324	-	-
Actual return on plan assets	43,038	36,394	-	-

Employer contributions		60,000		-		-		-
Benefits paid		(19,509)		(18,244)		-		-
Fair value at December 31		397,003		313,474		-		-
Funded status at end of year	$	(172,931)	$	(193,270)	$	(59,126)	$	(52,719)
Amounts recognized in the statement of financial position consist of:								
Other current liabilities	$	-	$	-	$	(3,289)	$	(3,244)
Noncurrent liabilities (1)		(172,931)		(193,270)		(55,837)		(49,475)
Net amount recognized	$	(172,931)		(193,270)	$	(59,126)	$	(52,719)
Amounts recognized in accumulated other comprehensive income consist of:								
Net loss	$	161,855	$	150,196	$	18,840	$	14,585
Prior service cost		1,855		2,505		1,744		1,977
Subtotal		163,710		152,701		20,584		16,562
Less amount recorded as regulatory asset		(163,710)		(152,701)		-		-
Net amount recognized in accumulated other comprehensive income	$	-	$	-	$	20,584	$	16,562
Accumulated benefit obligation	$	482,448	$	425,744	$	54,213	$	48,563

(1) Noncurrent liabilities are contained in Idaho Power's Balance Sheets under and "Other deferred credits."

The following table shows the components of net periodic benefit cost for these plans:

	Pension Plan		SMSP	
	2010	2009	2010	2009
Service cost	$ 17,671	$ 16,514	$ 1,541	$ 1,610
Interest cost	29,119	27,865	3,004	2,854
Expected return on assets	(26,463)	(23,965)	-	-
Amortization of net loss	7,675	8,857	931	232
Amortization of prior service cost	650	650	233	659
Net periodic pension cost	28,652	29,921	5,709	5,355
Costs not recognized due to the effects of regulation (1)	(24,104)	(28,669)	-	-
Net periodic benefit cost recognized for financial reporting (2)	$ 4,548	$ 1,252	$ 5,709	$ 5,355

(1) Under IPUC order, income statement recognition of pension plan costs has been deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's 2010 pension rate filing.

(2) Net periodic benefit costs for the pension plan are recognized for the Oregon jurisdiction and non-regulated subsidiaries, and beginning in June 2010, for the Idaho and FERC jurisdictions.

In 2011, Idaho Power expects to recognize as components of net periodic benefit cost $10.6 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2010, relating to the pension and SMSP plans. This amount consists of $8.4 million of amortization of net loss and $0.7 million of amortization of prior service cost for the pension plan, and $1.3 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:

	2011	2012	2013	2014	2015	2016-2020
			(thousands of dollars)			
Pension Plan	$ 21,229	$ 22,791	$ 24,748	$ 26,554	$ 28,656	$ 180,364
SMSP	$ 3,371	$ 3,491	$ 3,695	$ 3,869	$ 4,016	$ 21,816

Pension Protection Act: In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid benefit restrictions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of the funding requirements. Idaho Power has elected to use asset smoothing.

On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from a range of months in selecting a yield curve, rather than requiring the use of prescribed rates. The Treasury's announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. The revisions in the PPA, WRERA, Treasury guidance, and IRS guidance resulted in Idaho Power revising the funded status as of January 1, 2009, effectively reducing or delaying the required contributions from Idaho Power from what would otherwise be required, and what was previously disclosed. At January 1, 2009, Idaho Power's pension plan was above the minimum required funding levels as revised by the PPA, WRERA, Treasury guidance and IRS guidance, but below the minimum required funding levels at January 1, 2010, and is projected to stay below the minimum required funding levels through 2015. As Idaho Power's pension plan was below the minimum required funding levels at January 1, 2010, future minimum contributions are required. Based on the provisions and methodologies allowed under the PPA, WRERA, Treasury guidance, and IRS guidance, Idaho Power was not required to contribute to their pension plan in 2009. Unless Idaho Power elects an alternative amortization schedule under the new legislation discussed below, minimum required contributions to the defined benefit pension plan are estimated to be approximately $3 million in 2011, $46 million in 2012, $36 million in 2013, $32 million in 2014, and $31 million in 2015. Idaho Power may elect to make contributions earlier than the required dates.

The IRS and Treasury have issued final regulations effective October 15, 2009 that apply to plan years beginning on or after January 1, 2010. These regulations reflect provisions added by the PPA, as amended by the WRERA. These regulations affect sponsors, administrators, participants, and beneficiaries of single employer defined benefit pension plans. The regulations provide guidance regarding the determination of the value of plan assets and benefit liabilities for purposes of the funding requirements, regarding the use of certain funding balances maintained for those plans, and regarding benefit restrictions for certain underfunded defined benefit pension plans. These final regulations did not materially change existing estimates relating to pension plan contributions.

In June 2010, the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010 was signed into law, which permits employers to choose between two alternative funding options for defined benefit pension plans for any two plan years between 2008 and 2011, either (i) amortizing the funding shortfall for the applicable years over 15 years or (ii) paying interest only on the applicable plan years' funding shortfall for two plan years followed by amortization of the actual shortfall for 7 years. If an alternate funding option is elected for plan year 2011, the only remaining plan year for which the company could make an election, it would reduce near-term required contributions to the plan by spreading them over a longer time period. The legislation does not eliminate Idaho Power's obligation to fully fund the pension plan. In addition, the legislation outlines penalties in the form of increased pension contributions from an employer that elects one of the funding relief options at the same time that employer (or entities within its ERISA-controlled group) awards "excess employee compensation" (generally compensation over $1 million per year paid to an employee), grants "excessive" dividends, or effects specified stock redemptions. Idaho Power will evaluate the legislation and its alternatives further prior to electing an alternative, if any. See Note 3 for a discussion of Idaho Power's recovery of pension plan contributions through the ratemaking process.

Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact funding requirements. Idaho Power will continue to monitor the legislative and regulatory environments for additional changes, evaluating them for their potential impact on funding requirements and strategies.

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

	2010	2009
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 62,647	$ 59,648
Service cost	1,276	1,221
Interest cost	3,578	3,565
Actuarial loss	3,291	2,128
Benefits paid(1)	(3,373)	(3,915)
Plan amendments	629	-
Benefit obligation at December 31	68,048	62,647
Change in plan assets:		
Fair value of plan assets at January 1	30,892	25,283
Actual return on plan assets	3,381	5,609
Employer contributions	2,276	3,915
Benefits paid(1)	(3,373)	(3,915)
Fair value of plan assets at December 31	33,176	30,892
Funded status at end of year (included in noncurrent liabilities)(2)	$ (34,872)	$ (31,755)

(1) Benefits paid are net of $2,791 and $2,731 of plan participant contributions, and $415 and $385 of Medicare Part D subsidy receipts for 2010 and 2009, respectively.
(2) Noncurrent liabilities are contained in "Other deferred credits."

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

	2010	2009
Net loss	$ 15,963	$ 14,112
Prior service credit	(426)	(1,537)
Transition obligation	4,080	6,120
Subtotal	19,617	18,695
Less amount recognized in regulatory assets	(19,032)	(15,235)
Less amount included in deferred tax assets	(585)	(3,460)
Net amount recognized in accumulated other comprehensive income	$ -	$ -

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

	2010	2009
Service cost	$ 1,276	$ 1,221
Interest cost	3,578	3,565
Expected return on plan assets	(2,503)	(2,146)
Amortization of net loss	562	842
Amortization of prior service cost	(482)	(535)
Amortization of unrecognized transition obligation	2,040	2,040
Net periodic postretirement benefit cost	$ 4,471	$ 4,987

In 2011, Idaho Power expects to recognize as components of net periodic benefit cost $2.3 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2010 relating to the postretirement benefit plan. This amount consists of ($0.4) million of prior service cost, $0.7 million of net loss, and $2.0 million of transition obligation.

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

The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act were enacted in March 2010. One provision of this legislation eliminates the deductibility of employer health care costs for retiree prescription drug expenses that are covered by federal subsidy payments equivalent to Medicare Part D. While this provision is not effective until 2013, relevant income tax accounting guidance requires recognition of the future effects of new law in the period of enactment. Due to the regulatory treatment of postretirement benefit costs, the increase in certain postretirement costs relating to the legislation is deferred as a regulatory asset. See Note 2 for the tax impacts recorded as a result of this legislation.

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):

	2011	2012	2013	2014	2015	2016-2020
Expected benefit payments	$ 4,300	$ 4,400	$ 4,600	$ 4,800	$ 4,900	$ 25,600
Expected Medicare Part D subsidy receipts	$ 500	$ 500	$ 600	$ 600	$ 700	$ 4,400

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the plan was 7.5 percent and 8.0 percent in 2010 and 2009, respectively. The assumed health care cost trend rate for 2010 is assumed to decrease gradually to 4.9 percent by 2070. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5 percent in both 2010 and 2009. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2010 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 309	$ (233)
Effect on accumulated postretirement benefit obligation	$ 2,842	$ (2,233)

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 Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
Discount rate	5.4%	5.9%	5.4%	5.9%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	7.5%	8.0%
Dental trend rate	-	-	5.0%	5.0%
Measurement date	12/31/10	12/31/09	12/31/10	12/31/09

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 Benefits		Postretirement Benefits	
	2010	**2009**	**2010**	**2009**
Discount rate	5.90%	6.10%	5.90%	6.10%
Expected long-term rate of return on assets	8.25%	8.50%	8.25%	8.50%
Rate of compensation increase	4.50%	4.50%	-	-
Medical trend rate	-	-	7.50%	8.00%
Dental trend rate	-	-	5.00%	5.00%

Plan Assets:
Idaho Power's pension plan and postretirement benefit plan assets at December 31, by asset category, are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	**2010**	**2009**	**2010**	**2009**
Cash and cash equivalents	$ 16,837	$ 4,512	$ -	$ -
Short-term bonds	30,241	30,774	-	-
Core bonds	43,156	41,165	-	-
Equity securities	230,666	184,562	-	-
Real estate	22,069	20,783	-	-
Private market investments	29,932	20,202	-	-
Commodities	24,102	11,476	-	-
Other(1)	-	-	33,176	30,892
Total	$ 397,003	$ 313,474	$ 33,176	$ 30,892

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

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2010 for the portfolio by asset class are as follows:

	Target Allocation	Actual Allocation December 31, 2010
Large-cap growth stocks	6%	7.5%
Large-cap value stocks	6%	7.2%
Mid-cap growth stocks	4%	4.2%
Mid-cap value stocks	4%	3.9%
Small-cap growth stocks	4%	3.9%
Small-cap value stocks	4%	5.0%
Micro-cap stocks	4%	4.4%
International growth stocks	6%	6.0%
International value stocks	6%	5.9%
International small-cap stocks	5%	5.0%
Emerging markets stocks	5%	5.1%
Commodities	6%	6.1%
Private market investments	8%	7.5%
Short-term bonds	10%	7.6%
Core bonds	14%	10.9%
Cash and cash equivalents	2%	4.2%
Real estate	6%	5.6%
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, as follows:

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

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

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

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

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the following hierarchy:

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

If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security. The following table sets forth by level within the fair value hierarchy a summary of the plans' investments measured at fair value on a recurring basis at December 31, 2010:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets at December 31, 2010				
Pension assets:				
Cash and cash equivalents	$ 16,837	$ -	$ -	$ 16,837
Short-term bonds	30,241	-	-	30,241
Core bonds	43,156	-	-	43,156
Equity securities	164,290	66,376	-	230,666
Real estate	-	-	22,069	22,069
Private market investments	-	-	29,932	29,932
Commodities	3,406	20,696	-	24,102
Total pension assets	$ 257,930	$ 87,072	$ 52,001	$ 397,003
Postretirement assets	$ -	$ 33,176	$ -	$ 33,176
Assets at December 31, 2009				
Pension assets:				
Cash and cash equivalents	$ 4,512	$ -	$ -	$ 4,512
Short-term bonds	30,774	-	-	30,774
Core bonds	41,165	-	-	41,165
Equity securities	126,049	58,513	-	184,562
Real estate	-	-	20,783	20,783
Private market investments	-	-	20,202	20,202
Commodities	-	11,476	-	11,476
Total pension assets	$ 202,500	$ 69,989	$ 40,985	$ 313,474
Postretirement assets	$ -	$ 30,892	$ -	$ 30,892

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, 2009	$ 17,863	$ 37,418	$ 55,281
Realized losses	(1,040)	(671)	(1,711)
Unrealized gains (losses)	3,103	(14,912)	(11,809)
Purchases, issuances, and settlements, net	276	(1,052)	(776)
Ending balance - December 31, 2009	20,202	20,783	40,985
Realized losses	-	(47)	(47)
Unrealized gains	1,284	2,211	3,495
Purchases, issuances, and settlements, net	8,446	(878)	7,568
Ending balance - December 31, 2010	$ 29,932	$ 22,069	$ 52,001

Employee Savings Plan
Idaho Power has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $5 million in each of 2010 and 2009.

Post-employment Benefits
Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and Idaho Power's consolidated balance sheets at December 31, 2010 and 2009 are $4.5 million and $5.2 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 2010 and 2009 (in thousands of dollars):

	2010		2009	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,792,305	2.23%	$ 1,758,813	2.23%
Transmission	855,202	2.03	768,260	2.07
Distribution	1,377,239	3.13	1,331,065	2.89
General and Other	307,308	7.41	302,040	7.88
Total in service	4,332,054	2.84%	4,160,178	2.81%
Accumulated provision for depreciation	(1,771,655)		(1,713,943)	
In service - net	$ 2,560,399		$ 2,446,235	

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

Idaho Power has interests in three jointly-owned generating facilities included in the table above. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of related fuel expenses as well as direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income.

These facilities, and the extent of Idaho Power's participation, were as follows at December 31, 2010 (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	$ 530,617	$ 8,472	$ 273,823	33	771
Boardman	Boardman, OR	72,176	1,267	52,364	10	64
Valmy Units 1 and 2	Winnemucca, NV	334,821	4,932	201,372	50	284

(1) Idaho Power's share of nameplate capacity

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in Bridger Coal Company. Idaho Power's coal purchases from the joint venture were $76 million and $66 million in 2010 and 2009, 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 $8 million and $9 million in 2010 and 2009, respectively.

12. ASSET RETIREMENT OBLIGATIONS (ARO):

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

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2010, changes in estimates at the coal-fired generation facilities resulted in a net increase of $0.9 million in the recorded ARO.

Idaho Power also has AROs associated with its transmission system and hydroelectric 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.

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

	2010	2009
Balance at beginning of year	$ 16,240	$ 12,415
Accretion expense	819	697
Revisions in estimated cash flows	929	3,684
Liability incurred	-	139
Liability settled	(1,036)	(695)

Balance at end of year	$	16,952	$	16,240

13. INVESTMENTS:

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

		2010		2009
Idaho Power investments:				
Equity method investment	$	90,495	$	83,969
Available-for-sale equity securities		24,561		18,842
Executive deferred compensation plan		4,746		5,217
Other investments		3		267
Total Idaho Power investments	$	119,805	$	108,295

Equity Method Investments
Idaho Power, through its subsidiary IERCo, is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The following table presents Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

		2010		2009
Bridger Coal Company - IERCO	$	11,281	$	8,256

Investments in Debt and Equity Securities
Investments in debt and equity 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 following table summarizes investments in debt and equity securities (in thousands of dollars):

	2010			2009		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 4,876	$ -	$ 24,561	$ 2,989	$ -	$ 18,842

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

		2010		2009
Proceeds from sales	$	-	$	9,006
Gross realized gains from sales		-		11
Gross realized losses from sales		-		35

These investments are evaluated as of the end of each reporting period to determine whether they have experienced a decline in market value that is other-than-temporary. At December 31, 2010 and 2009, Idaho Power did not have any securities that were in a loss position.

14. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may 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. 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, including renewable energy certificates, qualify for the normal purchases and normal sales exception. Because of Idaho Power's power cost adjustment mechanisms, unrealized gains and losses associated with the changes in fair value of these derivative instruments are recorded as regulatory assets or liabilities.

Derivative Commodity Contracts

As of December 31, 2010, Idaho Power had the following outstanding derivative commodity forward contracts that were entered into for the purpose of economically hedging forecasted purchases and sales:

Commodity	Number of Units	
Electricity purchases	347,400	MWh
Electricity sales	338,200	MWh
Natural gas purchases	647,900	MMBtu
Diesel	1,061,969	gallons

The following table presents the fair values and locations of derivative instruments recorded in the balance sheet at December 31, 2010 and 2009 (in thousands of dollars):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
December 31, 2010				
Current:				
Financial swaps	Other current assets	$ 930	Other current assets	$ 356
Financial swaps	Other current liabilities	2,440	Other current liabilities	4,172
Forward contracts			Other current liabilities	508
Long-term:				
Financial swaps	Other liabilities	100	Other liabilities	138
Total		$ 3,470		$ 5,174
December 31, 2009				
Current:				
Financial swaps	Other current assets	$ 2,931	Other current assets	$ 2,087

Financial swaps	Other current liabilities	9	Other current liabilities	610
Forward contracts	Other current liabilities	354	Other current liabilities	-
Long-term:				
Financial swaps	Other assets	442	Other assets	229
Total		$ 3,736		$ 2,926

The following table presents gains and losses on derivatives for the years ended December 31, 2010 and 2009 (in thousands of dollars):

Commodity derivatives	**Location of Gain/(Loss) Recognized in Income on Derivative**	**Amount of Gain/(Loss) Recognized in Income on Derivative**(1)
Year ended December 31, 2010:		
Financial swaps	Off-system sales	$ 4,499
Financial swaps	Purchased power	(12,240)
Financial swaps	Fuel expense	(101)
Forward contracts	Fuel expense	(721)
Year ended December 31, 2009:		
Financial swaps	Off-system sales	$ 3,245
Financial swaps	Purchased power	(3,966)
Financial swaps	Fuel expense	(5,794)
Forward contracts	Fuel expense	(986)

(1)Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or 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, which are recorded in fuel inventory on the balance sheet, were immaterial for all three years. See Note 15 for additional information concerning the determination of the fair value of Idaho Power's assets and liabilities from price risk management activities.

Credit Risk

At December 31, 2010, 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. The majority of Idaho Power's contracts are under the form of the Western Systems Power Pool agreement that provides for adequate assurances if a counterparty has debt that is downgraded to below investment grade by at least one rating agency. Idaho Power also requires North American Energy Standards Board contracts as necessary for physical gas transactions, and International Swaps and Derivatives Association, Inc. contracts as needed for financial transactions.

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 Investor Services 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 are in a liability position on December 31, 2010, is $5.2 million. Idaho Power has posted $4.6 million of collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, Idaho Power could have been required to post $0.5 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS:

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

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

- Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that Idaho Power has the ability to access.
- Level 2: Financial assets and liabilities whose values are based on the following:
  a) Quoted prices for similar assets or liabilities in active markets;
  b) Quoted prices for identical or similar assets or liabilities in non-active markets;
  c) Pricing models whose inputs are observable for substantially the full term of the asset or liability; and
  d) Pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

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

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

Idaho Power's 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 basis location, 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, 2010 and 2009 (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 periods presented. See Note 10 for fair value information regarding Idaho Power's benefit plans.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
2010				
Assets:				
Derivatives	$ 573	$ -	$ -	$ 573
Money market funds	151,173	-	-	151,173
Trading securities	4,746	-	-	4,746

Available-for-sale equity securities	24,561	-	-	24,561
Liabilities:				
Derivatives	-	508	-	508
2009				
Assets:				
Derivatives	$ 1,056	$ 354	$ -	$ 1,410
Money market funds	19,364	-	-	19,364
Trading securities	5,217	-	-	5,217
Available-for-sale equity securities	18,842	-	-	18,842
Liabilities:				
Derivatives	601	-	-	601

The following tables present the carrying value and estimated fair value of financial instruments that are not reported at fair value, 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 analyses as appropriate.

	December 31, 2010		**December 31, 2009**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
	(thousands of dollars)			
Liabilities:				
Long-term debt	$ 1,612,790	$ 1,621,425	$ 1,413,854	$ 1,398,681

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 and $0.9 million in 2010 and 2009, respectively.

Ida-West

Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Ida-West is a wholly-owned subsidiary of IDACORP, Inc. Idaho Power paid $8 million and $9 million to Ida-West in 2010 and 2009, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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)	4,332,508,702	4,332,508,702
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,332,508,702	4,332,508,702
9	Leased to Others		
10	Held for Future Use	7,076,146	7,076,146
11	Construction Work in Progress	416,949,593	416,949,593
12	Acquisition Adjustments	-454,450	-454,450
13	Total Utility Plant (8 thru 12)	4,756,079,991	4,756,079,991
14	Accum Prov for Depr, Amort, & Depl	1,771,654,529	1,771,654,529
15	Net Utility Plant (13 less 14)	2,984,425,462	2,984,425,462
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,750,735,946	1,750,735,946
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	21,337,054	21,337,054
22	Total In Service (18 thru 21)	1,772,073,000	1,772,073,000
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	-418,471	-418,471
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,771,654,529	1,771,654,529

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	-46,004	51,707
3	(302) Franchises and Consents	21,620,769	1,544,768
4	(303) Miscellaneous Intangible Plant	34,760,040	4,760,093
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,334,805	6,356,568
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,370,320	225,421
9	(311) Structures and Improvements	138,632,198	2,342,621
10	(312) Boiler Plant Equipment	535,996,056	27,087,429
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	134,758,504	17,657,531
13	(315) Accessory Electric Equipment	62,010,255	604,886
14	(316) Misc. Power Plant Equipment	15,184,798	957,711
15	(317) Asset Retirement Costs for Steam Production	3,585,511	-69,524
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	891,537,642	48,806,075
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	30,823,031	-709,228
28	(331) Structures and Improvements	153,562,171	1,942,473
29	(332) Reservoirs, Dams, and Waterways	250,236,942	564,264
30	(333) Water Wheels, Turbines, and Generators	192,732,014	1,706,402
31	(334) Accessory Electric Equipment	42,752,897	1,252,068
32	(335) Misc. Power PLant Equipment	17,959,833	867,976
33	(336) Roads, Railroads, and Bridges	7,492,685	29,108
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	695,559,573	5,653,063
36	D. Other Production Plant		
37	(340) Land and Land Rights	402,746	2,196,949
38	(341) Structures and Improvements	7,169,595	
39	(342) Fuel Holders, Products, and Accessories	4,445,866	
40	(343) Prime Movers	92,651,571	8,150,065
41	(344) Generators	39,093,026	-7,411,126
42	(345) Accessory Electric Equipment	24,899,230	128,368
43	(346) Misc. Power Plant Equipment	3,054,175	64,469
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	171,716,209	3,128,725
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,758,813,424	57,587,863

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
			23,165,537		3
6,536,552			32,983,581		4
6,536,552			56,154,821		5
					6
					7
-8,291			1,604,032		8
1,809,612			139,165,207		9
14,017,871			549,065,614		10
					11
3,616,146			148,799,889		12
2,728,385			59,886,756		13
655,960			15,486,549		14
			3,515,987		15
22,819,683			917,524,034		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
3,834			30,109,969		27
79,259			155,425,385		28
50,328			250,750,878		29
161,151			194,277,265		30
242,880			43,762,085		31
739,125			18,088,684		32
			7,521,793		33
					34
1,276,577			699,936,059		35
					36
			2,599,695		37
			7,169,595		38
			4,445,866		39
			100,801,636		40
			31,681,900		41
			25,027,598		42
			3,118,644		43
					44
			174,844,934		45
24,096,260			1,792,305,027		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	04/15/2011	End of 2010/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	31,028,848	3,227,413
49	(352) Structures and Improvements	43,115,497	12,772,297
50	(353) Station Equipment	304,153,598	53,454,147
51	(354) Towers and Fixtures	139,305,363	5,418,177
52	(355) Poles and Fixtures	95,225,302	6,886,404
53	(356) Overhead Conductors and Devices	155,113,007	14,576,603
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	318,351	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	768,259,966	96,335,041
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,720,970	24,219
61	(361) Structures and Improvements	26,949,318	2,684,247
62	(362) Station Equipment	181,364,474	3,711,194
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	217,058,551	9,432,943
65	(365) Overhead Conductors and Devices	121,129,198	514,695
66	(366) Underground Conduit	48,299,409	-19,750
67	(367) Underground Conductors and Devices	186,973,846	5,201,635
68	(368) Line Transformers	401,884,459	17,736,409
69	(369) Services	56,506,757	1,094,460
70	(370) Meters	79,041,844	18,781,574
71	(371) Installations on Customer Premises	2,655,578	193,840
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,247,818	169,561
74	(374) Asset Retirement Costs for Distribution Plant	232,370	355,610
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,331,064,592	59,880,637
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	10,761,268	418,905
87	(390) Structures and Improvements	76,656,381	1,281,788
88	(391) Office Furniture and Equipment	40,825,812	3,669,556
89	(392) Transportation Equipment	58,924,843	3,743,616
90	(393) Stores Equipment	1,330,794	171,621
91	(394) Tools, Shop and Garage Equipment	5,250,205	386,103
92	(395) Laboratory Equipment	11,551,486	826,418
93	(396) Power Operated Equipment	9,240,588	687,555
94	(397) Communication Equipment	27,393,124	2,587,431
95	(398) Miscellaneous Equipment	4,225,136	637,268
96	SUBTOTAL (Enter Total of lines 86 thru 95)	246,159,637	14,410,261
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)	246,159,637	14,410,261
100	TOTAL (Accounts 101 and 106)	4,160,632,424	234,570,370
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)	4,160,632,424	234,570,370

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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
2,323			34,253,938		48
220,357			55,667,437		49
8,156,354			349,451,391		50
			144,723,540		51
490,213			101,621,493		52
524,015			169,165,595		53
					54
					55
			318,351		56
					57
9,393,262			855,201,745		58
					59
			4,745,189		60
147,703			29,485,862		61
2,481,706			182,593,962		62
					63
1,431,589			225,059,905		64
1,508,292			120,135,601		65
63,945			48,215,714		66
681,268			191,494,213		67
4,838,735			414,782,133		68
281,308			57,319,909		69
2,125,893			95,697,525		70
98,519			2,750,899		71
					72
46,865			4,370,514		73
			587,980		74
13,705,823			1,377,239,406		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
56,411			11,123,762		86
659,555			77,278,614		87
5,119,827			39,375,541		88
1,711,154			60,957,305		89
43,075			1,459,340		90
68,786			5,567,522		91
431,209			11,946,695		92
5,961			9,922,182		93
766,410			29,214,145		94
99,807			4,762,597		95
8,962,195			251,607,703		96
					97
					98
8,962,195			251,607,703		99
62,694,092			4,332,508,702		100
					101
					102
					103
62,694,092			4,332,508,702		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	04/15/2011	End of 2010/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		762,521
3	Production			112,704
4	Transmission Stations			429,822
5	Transmission Lines			68,619
6	Distribution Stations			1,074,920
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	Boise Operations Center	12/31/82		72,785
12	Transmission Stations	12/31/81		199,069
13	Distribution Stations			72,016
14	Homedale Substation	2/29/08		215,719
15	Beacon Light Substation	12/30/02		554,378
16				
17				
18				
19	Column B if no date listed it is various			
20				
21	Other Property:			
22				
23				
24				
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46				
47	Total			7,076,146

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	LANGLEY GULCH POWER PLANT CONS	193,642,197
2	ROLLUP RELIC COST BROWNLEE	46,774,350
3	ROLLUP RELIC COST HELLS CANYON	32,030,925
4	ROLLUP RELIC COST OXBOW	14,704,586
5	GATEWAY WEST 500KV LINE	14,313,770
6	BOARDMAN - HEMINGWAY 500 KV LI	13,576,716
7	HELLS CANYON RELICENSING OUTSI	11,939,746
8	CIAC LIABILITY RECLASS	5,991,287
9	WQ - ONGOING HELLS CANYON RELI	5,073,688
10	BRIDGER 2007C207 U3 SO2 EMIS C	4,064,825
11	RIVER ENG.-HELLS CANYON CONTIN	3,165,288
12	HCC RELICENSING FISH2004 FEASI	2,165,327
13	LANGLEY GULCH SWITCHYARD	2,125,776
14	REL-HELLS CANYON COMPLEX FY200	2,103,067
15	HCC RELICENSING, FISH2004 INST	2,101,401
16	CIAC LIABILITY RECLASS-PROJECT	2,069,855
17	MPSN0802 INCREASE CAPACITY OF	2,050,510
18	HCC RELICENSING, FISH2004 REDB	2,045,023
19	LANGLEY GULCH 230 KV DOUBLE CI	1,935,273
20	HCC RELICENSING, FISH2004 ANAD	1,707,975
21	LANGLEY GULCH PP CONST: WATER	1,688,355
22	VTRY ADD 2ND 138 LINE BAY	1,642,830
23	PAYROLL & IBNR ACCRUAL	1,566,781
24	CJ STRIKE #3 TURBINE RUNNER RE	1,488,366
25	AERATION FOR UNIT #5 TO IMPROV	1,294,073
26	BKFT1001 - REPLACE METALCLAD S	1,278,390
27	ROLLUP RELIC COST SWAN FALLS	1,260,525
28	REL-HCC OREGON REAUTHORIZATION	1,236,182
29	LEGAL DEPT. LABOR FOR RELICENS	1,235,515
30	SWAN FALLS RELICENSING	1,230,436
31	VALMY 98238682 REPL EVAP POND	1,217,269
32	BRIDGER 2008C132 U3 TURBINE UP	1,119,403
33	CUSTOMER SERVICE CALL MANAGEME	1,105,913
34	OTHER MINOR PROJECTS UNDER $1,000,000	36,003,970
35		
36		
37		
38		
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40		
41		
42		
43	TOTAL	416,949,593

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,693,322,507	1,693,322,507		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	109,099,197	109,099,197		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,856,703	2,856,703		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,272	108,272		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	112,064,172	112,064,172		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	48,656,596	48,656,596		
13	Cost of Removal	8,150,930	8,150,930		
14	Salvage (Credit)	2,024,882	2,024,882		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	54,782,644	54,782,644		
16	Other Debit or Cr. Items (Describe, details in footnote):	131,911	131,911		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,750,735,946	1,750,735,946		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	522,242,776	522,242,776		
21	Nuclear Production				
22	Hydraulic Production-Conventional	337,974,005	337,974,005		
23	Hydraulic Production-Pumped Storage				
24	Other Production	28,158,063	28,158,063		
25	Transmission	264,169,778	264,169,778		
26	Distribution	497,188,284	497,188,284		
27	Regional Transmission and Market Operation				
28	General	101,003,040	101,003,040		
29	TOTAL (Enter Total of lines 20 thru 28)	1,750,735,946	1,750,735,946		

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

Relocation reimbursements, Up and down costs and damage and insurance claims $ 182,401

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

Accumulated Provision for Depreciation on Asset Retirement Obligation $ 131,911

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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			62,552,347
5				
6	Subtotal Idaho Energy Resources Company			65,015,441
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	65,015,441

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
7,546,332		70,098,680		4
				5
7,546,332		72,561,774		6
				7
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7,546,332		72,561,774		42

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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)	25,633,645	27,546,983	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)	14,273,494	14,416,312	
8	Transmission Plant (Estimated)	13,295,452	13,365,654	
9	Distribution Plant (Estimated)	15,059,387	13,541,576	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	713,727	897,634	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	43,342,060	42,221,176	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)	4,711,966	3,379,745	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	73,687,671	73,147,904	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Asset Retirement Obligations- IPUC	14,749,123	1,251,626	Various	628,964	15,371,785
2	Order# 29414-OPUC Order# 04-585					
3						
4	SFAS 133 Mark to Market	280,459	12,958,490	244	10,999,255	2,239,694
5						
6	Regulatory Unfunded Accu Def Inc Tax Noncurrent	391,835,998	207,260,065	282	10,501,413	588,594,650
7						
8	PCA Deferral- IPUC order	32,277,040	47,277,755	Various	49,273,716	30,281,079
9	#27660 (amort period 6/05 thru 5/07)					
10						
11	PCA Prior Year Deferral - IPUC Order	39,134,552	12,751,188	Various	64,607,616	-12,721,876
12	#27660 (amort period 06/09 thru 05/10)					
13						
14	Fixed Cost Adjusment (FCA) Order #30267	6,581,458	9,489,666	1823/401	6,596,995	9,474,129
15	(amort period 06/09 thru 05/10)					
16						
17	Prior Year FCA Order #30267	1,254,247	6,602,763	400	4,990,495	2,866,515
18						
19	Idaho - Demand Side Management - IPUC order	1,621,331	270,217	401	1,891,548	
20	#27660 (amort period 7/98 thru 6/10)					
21						
22	Excess Power Deferral 06/07 - IPUC Order #07-555	1,542,629	465,703	Various	1,978,946	29,386
23	(amort period 10/09 thru 02/12)					
24						
25	IPUC Grid West loans - IPUC order #30157	372,871	15,536	1823/401	201,973	186,434
26	(amort period 1/07 - 12/11)					
27						
28	FERC Grid West Expense - ER08-629-000	279,321	6,983	401	90,779	195,525
29	(amort period 05/08 thru 04/13)					
30						
31	SFAS 106/158 Past Retirement Benefits	15,324,165	5,917,008	2283	2,209,430	19,031,743
32	IPUC order #30256					
33						
34	SFAS 87/158 Pension Accumulated	(1,925,704)	2,888,556	282	160,100,880	-159,138,028
35	IPUC order #30256					
36						
37	Pension Deferred FERC Portion	715,538	645,878	1823/2283	1,211,025	150,391
38						
39	Pension Deferred Oregon Order UE-213	572,286	416,002	2283/4073	48,398	939,890
40						
41	FAS 87 Deferred Pension-IPUC order #30333	37,963,279	33,407,805	Various	62,821,496	8,549,588
42						
43	FIN 48 Adjustment-Interest Payable-Order #30256	152,701,210	20,256,283	2283	9,247,401	163,710,092
44	TOTAL	715,831,853	501,942,326		456,348,295	761,425,884

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	ID DSM Rider Reclass- 29026	9,718,518	50,188,794	254	42,314,374	17,592,938
3						
4	PCAM Oregon 2008 Order #08-238	5,485,419	1,119,455	1823/254	648,201	5,956,673
5						
6	PCAM Interest Reserve 2008 Order #08-238		390,563	Various	669,237	-278,674
7						
8	Excess Power Deferral 2007	6,193,112	1,408,245	1823/4210	636,666	6,964,691
9	IPUC order #09-189					
10						
11	2007 EPC Interest Reserve Order #09-189		612,484	1823/4210	1,065,243	-452,759
12						
13	Oregon DSM Rider Reclass- Advice #05-03	866,772	5,337,393	254	4,330,490	1,873,675
14						
15	2009 Reorg order #30914	1,145,203	27,296	401	249,877	922,622
16	(amort period 01/10 thru 12/14)					
17						
18	OATT Revenue Deferred Reserve Order #30940	4,686,838	2,941,239	186/4210	2,952,895	4,675,182
19	(amort period 01/11 thru 12/13)					
20						
21	Idaho Pension Cash PUC Order #31091		62,658,778	1823/401	9,489,405	53,169,373
22	(amort period 06/10 - 05/11)					
23						
24	FERC Pension Cash		1,207,024	1823/401	182,957	1,024,067
25	(amort period 06/10 -05/11)					
26						
27	Regulatory Unfunded Accu Def Inc Tax Current	(7,774,317)	7,774,317			
28						
29	Minor items (17)	230,505	6,395,214	Various	6,408,620	217,099
30						
31						
32						
33						
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36						
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41						
42						
43						
44	TOTAL	715,831,853	501,942,326		456,348,295	761,425,884

Schedule Page: 232.1 Line No.: 23 Column: c

Idaho Public Service Commission has authorized amortization of $5.4 million over 12 months.

Schedule Page: 232.1 Line No.: 26 Column: c

FERC has authorized amortization fo $104 thousand over 12 months.

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Rents - Rights of way	270,368	579,928	401	76,711	773,585
2						
3	2008 Poll Control Bond Refin	4,347,901	18,810	181/232	4,354,700	12,011
4						
5	Advance prepaid coal royalties	1,507,205	3,006	Various	76,992	1,433,219
6						
7	Security plan	20,866,261	701,574	165	520,406	21,047,429
8						
9	American Falls bond refinance	220,709		401	14,552	206,157
10	(amort period 4/00 thru 7/26)					
11						
12	Prepaid Credit Facility	253,368		431	193,068	60,300
13						
14	Company owned Life Insurance	5,787,403	1,596,192	Various	1,759,192	5,624,403
15						
16	American Falls water rights	15,716,965		401	1,042,009	14,674,956
17	(amort period 1/06 thru 12/25)					
18						
19	Milner bond guarantee	8,509,091		253	1,063,636	7,445,455
20	(amort period 2/07 - 2/17)					
21						
22	American Falls - bond refinance	727,987		401	47,999	679,988
23	(35 year amortization)					
24						
25	Shelf Registration - 2008	974,055	262,043	181/232	1,236,098	
26						
27	Shelf Registration - 2010		3,646,728	Various	1,262,834	2,383,894
28						
29	Transmission Deposit-PacifiCorp	661,875	177,741	Various	151,875	687,741
30						
31	Prepaid Peoplesoft/Passport	109,596	486,424	186/401	287,718	308,302
32						
33	Long Term Workers Compensation	1,328,786	1,328,786	Various	1,350,669	1,306,903
34						
35	OATT Revenue Deferred Reserve	-2,925,724	3,250,420	1823/431	2,935,409	-2,610,713
36	order #30940					
37	(amort period 3 years start					
38	date not yet determined)					
39						
40	Long-Term Firm Trans Deposits		941,654	Various	22,591	919,063
41						
42	Minor Items & Job Orders (9)	137,028	9,387,080	Various	9,345,329	178,779
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	58,492,874				55,131,472

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3	Emission Allowances	-847,076	-509,154
4	Advances for Construction	8,334,734	7,061,283
5	Other Electric (See footnote)	21,611,994	6,072,776
6			
7	Other (See footnote)	122,807,414	126,631,210
8	TOTAL Electric (Enter Total of lines 2 thru 7)	151,907,066	139,256,115
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric - See footnote	18,203,912	18,090,657
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	170,110,978	157,346,772

Notes

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

(Note 1):	Beginning Balance	Ending Balance
Post Retiree Benefits-VEBA	5,583,994	5,658,260
AFUDC Hells Canyon Relicensing	3,868,089	8,292,259
Rate Case Disallowance	2,881,031	2,765,193
Stock Based Compensation	2,235,008	2,496,071
Other Employee's Long Term Deferred Compensation	2,039,678	1,855,362
Post Retirement Benefits	1,765,736	1,504,637
Deferred Idaho ITC	1,656,363	4,183,991
Non-VEBA Pension and Benefits	573,602	414,231
Oregon-Pension Expense	471,584	817,276
FERC Credit OFA	424,728	182,024
IRS Interest Expense	113,033	93,084
Pension Expense (acct 228)	0	(22,197,832)
Deferred GBC	12,000	24,000
Bonus Deferral	(2,577)	(514)
Delivery Accruals	(10,275)	(15,266)
Total Other Electric	21,611,994	6,072,776

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

(Note 2):		
Pension	59,698,538	64,358,800
Regulatory Liability for Income Taxes	47,183,294	46,199,137
Postretirement Plan	9,450,830	8,025,874
Minimum Pension Liability	6,474,752	8,047,399
Total Other	122,807,414	126,631,210

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

Senior Management Security Plan	13,718,388	15,067,824
SMSP-Market Change of Rabbi Investments	2,669,975	1,626,015
Micron-CIAC	1,526,244	1,288,363
Meridian Gold Contributions	130,567	108,455
Bridger Sierra Reserve-Legal Fee's	97,738	-
Unrealized Loss on Investments	61,000	-
Total Non Electric	18,203,912	18,090,657

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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 OPUC UF4263 IPUC IPC-E-10-10 WPSC 20005-32-ES-10	100,000,000	498,864 D
13			
14	5.30% Series Due 2035	60,000,000	408,411 D
15			3,802,019
16			
17	6.60% Series due 2011	120,000,000	860,502
18			
19	4.25%Series due 2013	70,000,000	641,201
20			372,696 D
21			
22	4.75% Series due 2012	100,000,000	944,356
23			1,047,617 D
24			
25	6.00% Series due 2032	100,000,000	1,191,216
26			543,244 D
27			
28	5.875% Series due 2034	55,000,000	-585,759
29			746,961 D
30			
31	5.50% Series due 2034	50,000,000	524,419
32			383,322 D
33	TOTAL	1,617,045,000	24,685,286

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	6,150,000	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	1,142,778	12
						13
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	14
						15
						16
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	17
						18
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	19
						20
						21
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	22
						23
						24
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	25
						26
						27
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	28
						29
						30
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	31
						32
				1,612,790,455	80,490,049	33

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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			
2	4.85% Series Due 2040 OPUC UF4263 IPUC IPC-E-10-10 WPSC 20005-32-ES-10	100,000,000	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	Subtotal Account 221	1,585,460,000	24,685,286
20			
21	Account 222 - Reaquired Bonds		
22			
23	Account 223: Advances for Associated Companies		
24			
25	Account 224:		
26	Bond Guarantee - American Falls	19,885,000	
27	Note Guarantee - Milner Dam	11,700,000	
28	Subtotal Account 224	31,585,000	
29			
30			
31			
32			
33	TOTAL	1,617,045,000	24,685,286

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	1,630,139	2
						3
6/22/07	6/15/2037	6/22/07	6/15/2037	140,000,000	8,820,000	4
						5
						6
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	6,250,000	7
						8
						9
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	90,432	10
						11
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	12
						13
10/3/06	7/15/26	10/3/06	7/15/2026	116,300,000	6,105,750	14
						15
						16
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	17
						18
				1,585,460,000	80,490,049	19
						20
						21
						22
						23
						24
						25
04/26/00	2/1/25			19,885,000		26
02/10/92				7,445,455		27
				27,330,455		28
						29
						30
						31
						32
				1,612,790,455	80,490,049	33

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	140,634,223
2		[redacted]
3		
4	Taxable Income Not Reported on Books	
5		3,821,255
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10		9,304,215
11		
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15		23,765,263
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	[redacted]
20		114,861,271
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-3,475,271
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	-1,216,345
30		
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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) 04/15/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

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

004003-CONSTRUCTION ADV-252	$	(3,638,428)
004005-AVOIDED COST INT CAP		10,496,226
004010-EMISSION ALLOWANCE-254.409-411		2,022,525
004013-CIAC AS TAXABLE INC IN ACCT 107		(3,796,723)
004021-ENGINEERING FEES-IN ACCT 107-FED ONLY		23,493
004022-FERC CREDIT OFA-254.307		(620,808)
004506-CIAC-MERIDIAN GOLD		(56,560)
004507-CIAC-MICRON-DRAM		(608,470)
Total	$	3,821,255

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

Total Federal and State taxes deducted on books.	$	6,833,881
005001-BAD DEBT EXPENSE		(349,041)
005010-SFAS 112-POST-EMPLY BEN 182/253		(667,857)
005014-OVERACCRUED VACATION-ACCT 242		287,966
005017-INJURIES & DAMAGES		(81,597)
005019-DIRECTORS FEES DEF		281,628
005022-CAPITALIZED OVERHEADS		(10,000,000)
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.		600,000
005025-MILNER FALLING WATER - REV ACCRL		(429,332)
005027-AMORTIZATION OF ACCOUNT 114		(22,723)
005028-OREGON OPER PROPERTY TAX ADJ		(86,638)
005023-PENSION EXPENSE-Acct 228		(56,779,214)
005033-NONVEBA PEN&BEN-Acct 228		(407,649)
005035-PCA EXPENSE DEFERRAL		53,361,395
005043-AMERICAN FALLS - FALLING WATER CONTRACT-FT		219,181
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228		(471,456)
005052-AMORTIZATION OF ACCOUNT 181		211,660
005053-STOCK BASED COMPENSATION		103,433
005054-IPUC GRID WEST LOANS-ACCT 182		186,435
005055-OPUC GRID WEST LOANS-ACCT 182		10,624
005056-FERC GRID WEST EXP-ACCT 182		83,796
005057-INTERVENER FUNDING ORDERS-ACCT 182		(32,055)
005058-FIXED COST ADJUSTMENT (FCA)-ACCT 182		(4,504,939)
005059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF		71,720
005060-OREGON-PCAM (POWER COST ADJ MECHANISM)		(192,580)
005061-PENSION EXPENSE-OREGON		884,236
005501-SEC PLAN-NET INS COSTS		(201,936)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST		(407,115)
005504-NONDEDUCTIBLE POLITICAL EXP-426.4		823,695
005505-SEC PLAN-BENEFIT ACCR		2,383,660
005510-FINES & PENALTIES-OPERATING		(203,479)
005531-RATE CASE DISALLOWANCES-REVERSE AMORT		(296,299)
005532-DELIVERY ACCRUALS-253.550		(107,585)
005537-BRIDGER SIERRA RESERVE-LEGAL FEES-Acct 228.4		(250,000)
005540-UNREALIZED LOSS ON INVESTMENTS-Acct 124		(156,030)
Total	**$**	**(9,304,215)**

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

007010-AFUDC HC RELICENSING-ACCT 229	$	(11,316,461)

007011-OATT REVENUE DEFICIENCY		303,355
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		7,546,333
007502-ALLOWANCE FOR OFUDC		16,551,145
007503-ALLOWANCE FOR BFUDC		10,675,095
007504-RECLASS TAX EXEMPT INTEREST-FED ONLY		5,796
Total	**$**	**23,765,263**

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$	(249,151)
008009-DEPR FOR TAX GT OR LT BOOK		66,918,590
008016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D		(1,972,951)
008020-CONSERVATION PROGRAMS		7,259,992
008025-MANUFACTURING DEDUCTION		(229,000)
008027-NEVADA OPERATING PROPERTY TAX ADJ		34,869
008034-REMOVAL COSTS		8,144,207
008038-OREGON EXCESS PWR SUPPLY COSTS		(1,195,682)
008039-ST TAX-NOT DEDUCTED ON PRIOR RETURN		813,266
008041-AM FALLS - UNAMORTIZED DEBT EXP		(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT		(915,215)
008057-REORGANIZATION COSTS		(222,581)
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY		1,561,500
008073-REPAIRS DEDUCTION		30,000,000
008077-PP INS & OTR EXP (1 YR OR LESS)-165		(140,840)
008501-COLI-TAX ADJ FROM BOOKS		169,988
008504-OREGON NONOP PROPERTY TAX ADJUST		72
008703-IPCO - 162 (M) $1m THRESHOLD		(578,245)
IRS INTEREST EXPENSE		51,028
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		5,459,423
Total	$	114,861,271

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	-5,203,080		-62,281,493	-46,400,085	
3	Social Security - (FOAB)	2,124		12,457,819	12,459,015	
4	Unemployment			120,285	120,285	
5	Subtotal Federal	-5,200,956		-49,703,389	-33,820,785	
6						
7	State of Idaho:					
8	Property	5,673,820	225	14,934,613	14,373,248	
9	Non-Operating	21,866		17,978	28,188	
10	Income	-4,578,526		-5,372,288	-11,007,839	
11	KWH	119,182		1,645,778	1,667,811	
12	Unemployment	-3		1,071,470	1,071,471	-3
13	Regulatory Commission			1,837,184	1,837,184	
14	Business License - Sho Ban		150	300	150	
15	Subtotal Idaho	1,236,339	375	14,135,035	7,970,213	-3
16						
17	State of Oregon					
18	Property		1,090,708	2,228,127	2,397,398	
19	Non-Operating Property		766	1,605	1,676	
20	Income	-261,555		-118,383	-327,364	
21	Regulatory Commission	21,300		92,603	113,903	
22	Unemployment	7		36,776	36,776	7
23	Franchise	160,894		713,129	667,258	28,447
24	Subtotal Oregon	-79,354	1,091,474	2,953,857	2,889,647	28,454
25						
26	State of Montana:					
27	Property	119,148		210,443	224,454	
28	Subtotal Montana	119,148		210,443	224,454	
29						
30	State of Nevada:					
31	Property		533,334	1,108,774	1,143,643	
32	Business Tax					
33	Subtotal Nevada		533,334	1,108,774	1,143,643	
34						
35	State of Wyoming					
36	Corporate License			3,950	3,950	
37	Property	564,102		1,271,134	1,199,669	
38	Subtotal Wyoming	564,102		1,275,084	1,203,619	
39	Other States Income	106,794		-129,661	-32,802	
40	Payroll Adjustment			-13,686,351		
41	TOTAL	-3,253,927	1,625,183	-43,836,208	-20,422,011	28,451

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-21,084,488		-59,254,526			-3,026,967	2
927		12,457,819				3
		120,285				4
-21,083,561		-46,676,422			-3,026,967	5
						6
						7
6,798,477		14,934,613				8
11,656					17,978	9
1,057,025		-4,800,681			-571,607	10
97,149		1,645,778				11
-1		1,071,470				12
		1,837,184				13
		300				14
7,964,306		14,688,664			-553,629	15
						16
						17
	1,177,346	2,228,127				18
	838				1,605	19
-52,574		-91,673			-26,710	20
		92,603				21
		36,776				22
178,317		713,129				23
125,743	1,178,184	2,978,962			-25,105	24
						25
						26
105,137		210,443				27
105,137		210,443				28
						29
						30
	568,203	1,108,774				31
						32
	568,203	1,108,774				33
						34
						35
		3,950				36
635,567		1,271,134				37
635,567		1,275,084				38
9,936		-126,949			-2,712	39
		-13,686,351				40
-12,242,872	1,746,387	-40,227,795			-3,608,413	41

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

This footnote is for the total of Column I on page 263. The total of column I and the amounts associated with accounts 408.1 & 409.1 in column I should total back to the sum of lines 14, 15 & 16 on page 114. For the year 2010 this cross-check will not work as the total of lines 14-16 on page 114 is $ 73,298,449 additional expense than line 41 page 263. This difference represents an amount booked for the accounting of FIN #48. When FIN #48 was booked it does use account 409.1, however the other side of the entry is not assocaited with account 236 or 165. Therefore FIN #48 will show up on page 114 but will not be on pages 262 & 263.

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

Account	409.2	$ (2,812,996)
	234	(213,971)
Total		$ (3,026,967)

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

Account 409.2 $ 17,978

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

Account	409.2	$ (533,113)
	234	(38,494)
Total		$ (571,607)

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

Account 409.2 $ 1,605

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

Account	409.2	$ (24,753)
	234	(1,957)
Total		$ (26,710)

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

Account	409.2	$ (2,059)
	234	(653)
		$ (2,712)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	825,558				88,714	
4	7%						
5	10%	27,102,330				1,589,646	
6		1,293,701				26,723	
7		44,283,936	411.4	1,844,480	411.4	1,672,587	
8	TOTAL	73,505,525		1,844,480		3,377,670	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	44,283,936	411.4	1,844,481	411.4	1,672,587	
13							
14							
15							
16							
17							
18							
19							
20							
21							
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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) 04/15/2011	Year/Period of Report End of 2010/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
736,844	9.31		3
			4
25,512,684	17.05		5
1,266,978	48.41		6
44,455,829	26.48		7
71,972,335			8
			9
			10
			11
44,455,830			12
			13
			14
			15
			16
			17
			18
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			22
			23
			24
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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) 04/15/2011	Year/Period of Report End of 2010/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		various	52,765,478	62,803,733	10,038,255
2						
3	Point to Point Transmission Study	1,741,105	various	1,671,495	723,676	793,286
4						
5	FTV	4,866,666	400	400,000		4,466,666
6						
7	Sho Ban Trans ROW	378,150	242	115,650		262,500
8						
9	Delivery Accruals	97,063	107/401	622,605	544,592	19,050
10						
11	Milner Falling Water	1,861,890	186	1,063,636	634,305	1,432,559
12						
13	Postretirement Benefits	4,516,526	401	667,857		3,848,669
14						
15	Directors Deferred Compensation	4,329,923	131	340,677	622,304	4,611,550
16						
17	IBM Mainframe Software Licenses	1,514,798	232	393,486		1,121,312
18	(amort period 2010 - 2015)					
19						
20	Minor Items (2)	57,150	various	338,774	356,046	74,422
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
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41						
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43						
44						
45						
46						
47	TOTAL	19,363,271		58,379,658	65,684,656	26,668,269

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	282,033,763	40,025,883	37,265,774
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	282,033,763	40,025,883	37,265,774
6	Non-Operating Property			
7	Other - Regulatory Asset for I	382,135,977		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	664,169,740	40,025,883	37,265,774
10	Classification of TOTAL			
11	Federal Income Tax	558,484,600	39,880,644	36,776,391
12	State Income Tax	105,685,140	145,239	489,383
13	Local Income Tax			

NOTES

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.
		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)	(k)	
							1
						284,793,872	2
							3
							4
						284,793,872	5
							6
		182	157,212,324	182	197,291,823	422,215,476	7
							8
			157,212,324		197,291,823	707,009,348	9
							10
			131,878,198		172,229,488	601,940,143	11
			25,334,126		25,062,335	105,069,205	12
							13

NOTES (Continued)

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

	2,010	Changes during Year				Adj Dr		Adj Cr		2,010
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. cr g	Amt h	Acct. dr i	Amt j	Ending Balance k
Accelerated Depreciation	269,668,778	38,734,246	36,916,284							271,486,739
Intangible Asset-Labor Ded	13,029,653	230,969								13,260,623
Valmy Capitalized Items	504,266		76,500							427,766
Engineering Fees in Acct 107	(133,441)	13,210	21,433							(141,663)
Misc Software Develop Costs	365,323	(281,396)								83,927
Taxable CIAC in CWIP Bal.	(1,400,817)	1,328,853	251,557							(323,520)
TOTAL Line 2	282,033,763	40,025,883	37,265,774	0	0		0		0	284,793,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	42,494,735	15,097,692	31,936,419
4				
5				
6				
7				
8	Other -- See Note	66,858,132		
9	TOTAL Electric (Total of lines 3 thru 8)	109,352,867	15,097,692	31,936,419
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	59,496		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	109,412,363	15,097,692	31,936,419
20	Classification of TOTAL			
21	Federal Income Tax	91,781,031	12,664,760	26,789,995
22	State Income Tax	17,631,332	2,432,932	5,146,424
23	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
[redacted]							2
						25,656,008	3
							4
							5
							6
							7
					6,847,535	73,705,667	8
					6,847,535	99,361,675	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
276,772	70,783					265,485	18
276,772	70,783				6,847,535	99,627,160	19
[redacted]							20
232,171	59,376				5,744,099	83,572,690	21
44,601	11,407				1,103,436	16,054,470	22
							23

NOTES (Continued)

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

Account (a)	2010 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	Adj Dr Acct. cr g	Amt h	Adj cr Acct dr i	Amt j	2010 Ending Balance k
PCA Expense Deferral	27,918,362	8,843,833	29,705,470							7,056,724
Conservation Programs	4,772,178	4,116,522	1,278,228							7,610,472
Oregon Excess Power Costs	3,114,987		558,151							2,556,836
Oregon PCAM	2,144,525	240,617	165,328							2,219,814
IPUC Grid West Loans	145,774		72,887							72,887
OATT Revenue Deficiency	688,508	122,588	3,991							807,104
Reorganization Costs	447,717		87,018							360,699
FERC Grid West Expense	109,201		32,760							76,440
OPUC Grid West Loans	27,269	10	4,163							23,116
Intervenor Funding Orders	34,808	12,915	384							47,340
Fixed Cost Adjustment	3,063,369	1,761,206								4,824,575
PS & I Costs-Coal & CHP Plants	28,039		28,039							(0)
TOTAL	42,494,736	15,097,692	31,936,419	-	-		-		-	25,656,008

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

Pension	59,698,538							190	4,660,262	64,358,800
Postretirement Plan	5,990,982							190	1,449,478	7,440,460
Unrealized gains on Mkt Secu	1,168,611							219	737,796	1,906,407
TOTAL	66,858,132	-	-	-	-		-		6,847,535	73,705,667

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

Advance Coal Royalties	246,755			66,347	19,548					293,554
Oregon Non-Op Prop Tax Adj	299			28						328
Unrealized G/L From Rabbi Tst	(187,558)			210,397	51,236					(28,397)
TOTAL	59,496	-	-	276,772	70,783		-		-	265,485

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - IPUC Order #28661	502,669	175	1,027,997	1,098,554	573,226
2						
3	Oregon Solar Pilot -Advice # 10-11		Various	223,745	421,370	197,625
4						
5	FAS 133 - Market to Market - IPUC Order # 28661	212,580	175	470,500	257,920	
6						
7	Oregon Green Tags		182	28,227	223,492	195,265
8						
9	Emission Sales IEEP- Order #30529	479,101	Various	175,477	67,587	371,211
10						
11	Unfunded Accumulated Deferred Income Tax	47,183,294	190	4,336,426	3,352,270	46,199,138
12						
13	FERC Credit for OFA - IPUC Order #30754	1,086,401	401	672,542	51,734	465,593
14	(amort period 09/06 - 09/11)					
15						
16	Regulatory unfunded Accum Deferred Income Tax		Various	533,171	7,774,317	7,241,146
17						
18	Minor Items (4)	14,034	Various	389,048	411,712	36,698
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	49,478,079		7,857,133	13,658,956	55,279,902

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	400,606,630	409,479,319
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	338,716,361	339,240,028
5	Large (or Ind.) (See Instr. 4)	138,394,166	141,529,986
6	(444) Public Street and Highway Lighting	3,278,628	3,230,165
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	880,995,785	893,479,498
11	(447) Sales for Resale	78,133,502	94,373,321
12	TOTAL Sales of Electricity	959,129,287	987,852,819
13	(Less) (449.1) Provision for Rate Refunds	10,667,522	-2,551,647
14	TOTAL Revenues Net of Prov. for Refunds	948,461,765	990,404,466
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,532,831	3,811,350
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	21,141,127	18,272,233
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	44,517,995	32,457,459
22	(456.1) Revenues from Transmission of Electricity of Others	15,398,402	1,050,873
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	84,590,355	55,591,915
27	TOTAL Electric Operating Revenues	1,033,052,120	1,045,996,381

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,967,379	5,300,443	407,551	405,144	2
				3
5,439,730	5,476,690	81,571	81,532	4
3,075,379	3,140,209	124	127	5
30,016	30,938	1,459	1,372	6
				7
				8
				9
13,512,504	13,948,280	490,705	488,175	10
1,981,936	2,836,028			11
15,494,440	16,784,308	490,705	488,175	12
				13
15,494,440	16,784,308	490,705	488,175	14

Line 12, column (b) includes $ -3,346,469 of unbilled revenues.

Line 12, column (d) includes -25,409 MWH relating to unbilled revenues

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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) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	4,973,739	396,218,848	407,409	12,208	0.0797
3	03 - Residential Master Meter	4,957	377,729	22	225,318	0.0762
4	04 - Residential - EW	713	56,211	44	16,205	0.0788
5	05 - Residential - TOD	1,128	88,884	76	14,842	0.0788
6	15 - Dusk to dawn lighting	2,886	528,937			0.1833
7	Unbilled Revenues	-16,053	-1,074,454			0.0669
8	Other Revenues		4,411,323			
9	Total 440	4,967,370	400,607,478	407,551	12,188	0.0806
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	163,316	16,033,397	31,260	5,224	0.0982
13	09 - General service	409,534	23,044,182	181	2,262,619	0.0563
14	09 - General service	3,137,839	187,745,653	30,345	103,405	0.0598
15	09 - General service	5,321	299,881	3	1,773,667	0.0564
16	15 - Dusk to Dawn Light	4,159	691,087			0.1662
17	19 - Uniform rate contracts	2,109,565	98,195,956	116	18,185,905	0.0465
18	19 - Uniform rate contracts	7,166	368,986	1	7,166,000	0.0515
19	19 - Uniform rate contracts	114,540	5,282,385	4	28,635,000	0.0461
20	24 - Irrigation Pumping	1,706,632	110,511,488	18,609	91,710	0.0648
21	40 - General service	13,154	921,212	1,173	11,214	0.0700
22	Commercial & Industrial & Unbill	843,892	33,681,230	4	210,973,000	0.0399
23	Other Revenues		334,222			
24	Total 442	8,515,118	477,109,679	81,696	104,229	0.0560
25						
26	444 - Public Street Lighting:					
27	40 - General service	2,772	194,297	806	3,439	0.0701
28	41 - Street lighting	23,797	2,901,820	304	78,280	0.1219
29	42 - Traffic control lighting	3,379	173,468	349	9,682	0.0513
30	Other Revenues	68	9,043			0.1330
31	Total 444	30,016	3,278,628	1,459	20,573	0.1092
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,537,913	884,342,253	490,706	27,589	0.0653
42	Total Unbilled Rev.(See Instr. 6)	-25,409	-3,346,469	0	0	0.1317
43	TOTAL	13,512,504	880,995,784	490,706	27,537	0.0652

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Raft River Rural Electric	RQ	V6-44	8.804	8.804	7.612
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3						
4	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
5	Avista Corp.	OS	WSPP	n/a	n/a	n/a
6	Avista Corp.	SF	WSPP	n/a	n/a	n/a
7	Barclays Bank PLC	SF	WSPP	n/a	n/a	n/a
8	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
9	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
10	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
11	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
12	BP Energy Company	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**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
53,012	720,684	1,874,031	6,000	2,600,715	1
			283,995	283,995	2
					3
241,500		7,866,860		7,866,860	4
25		500		500	5
2,166		82,625		82,625	6
30,800		1,348,696		1,348,696	7
			2,239	2,239	8
10,819		432,266		432,266	9
6,261		190,686		190,686	10
96,800		3,628,220		3,628,220	11
85,200		3,826,100		3,826,100	12
40,800		1,412,936		1,412,936	13
			584,839	584,839	14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
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SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	WSPP	n/a	n/a	n/a
2	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
3	Chelan Co PUD	SF	WSPP	n/a	n/a	n/a
4	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
5	Conoco Phillips Company	SF	WSPP	n/a	n/a	n/a
6	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
7	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
8	Endure Energy, 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	JPMorgan Chase Bank, N.A.	OS	-	n/a	n/a	n/a
14	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
624		17,862		17,862	1
331,911		12,991,788		12,991,788	2
415		15,170		15,170	3
75,325		2,393,411		2,393,411	4
3,400		116,500		116,500	5
2,400		79,696		79,696	6
10,800		426,600		426,600	7
800		400		400	8
9,600		254,700		254,700	9
2,200		80,732		80,732	10
			2,104	2,104	11
76,208		2,989,230		2,989,230	12
		164,828		164,828	13
2,000		86,064		86,064	14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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:
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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.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
2	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
3	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
4	Morgan Stanley Capital Group Inc.	OS	V6-62	n/a	n/a	n/a
5	Morgan Stanley Capital Group Inc.	SF	V6-62	n/a	n/a	n/a
6	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
7	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
8	Northern California Power Agency	OS	WSPP	n/a	n/a	n/a
9	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
10	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
11	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
12	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
13	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
14	Portland General Electric Company	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	04/15/2011	End of 2010/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.
			1,377	1,377	1
73,575		3,329,198		3,329,198	2
		271,134		271,134	3
150		2,300		2,300	4
144,413		4,496,237		4,496,237	5
			67,560	67,560	6
400		16,808		16,808	7
15		715		715	8
			1,469	1,469	9
101		3,316		3,316	10
			1,211	1,211	11
1,800		66,180		66,180	12
			294	294	13
5,986		150,850		150,850	14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
2	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
3	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
4	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
5	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
6	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
7	Prudential Bache Commodities, LLC	OS	-	n/a	n/a	n/a
8	Public Service Company of Colorado	SF	WSPP	n/a	n/a	n/a
9	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
10	Puget Sound Energy, Inc.	SF	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	OS	WSPP	n/a	n/a	n/a
13	Rainbow Energy Marketing Corporation	SF	WSPP	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) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7,750		282,606		282,606	1
			268,597	268,597	2
47,875		1,055,388		1,055,388	3
55,691		1,780,720		1,780,720	4
			43,723	43,723	5
24,316		614,759		614,759	6
		3,748,887		3,748,887	7
3,121		118,470		118,470	8
6,545		170,350		170,350	9
10,837		357,055		357,055	10
			80,709	80,709	11
200		4,500		4,500	12
285,082		9,900,637		9,900,637	13
2,426		74,408		74,408	14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Seattle City Light	SF	WSPP	n/a	n/a	n/a
2	Sempra Energy Trading LLC	OS	-	n/a	n/a	n/a
3	Sempra Energy Trading LLC	OS	WSPP	n/a	n/a	n/a
4	Sempra Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
5	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
6	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
7	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
8	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
9	Sierra Pacific Power Co., dba NV Energy	SF	T-7	n/a	n/a	n/a
10	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
11	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
12	Southern California Edison	OS	WSPP	n/a	n/a	n/a
13	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
14	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
6,240		215,360		215,360	1
		751,140		751,140	2
			2,605	2,605	3
11,000		484,840		484,840	4
		242,496		242,496	5
			27,499	27,499	6
40,593		999,994		999,994	7
147,101		5,737,778		5,737,778	8
46		1,762		1,762	9
			128,305	128,305	10
7		199		199	11
			23	23	12
			5,244	5,244	13
23,600		720,590		720,590	14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	United Materials of Great Falls	LF	61	n/a	n/a	n/a
2						
3						
4	LESS BAD DEBT WRITE-OFF					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		26,447		26,447	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
53,012	720,684	1,874,031	289,995	2,884,710	
1,928,924	0	74,030,994	1,217,798	75,248,792	
1,981,936	**720,684**	**75,905,025**	**1,507,793**	**78,133,502**	

Schedule Page: 310 Line No.: 1 Column: b
Customer Charge
Schedule Page: 310 Line No.: 2 Column: b
Network Transmission Charges
Schedule Page: 310 Line No.: 5 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 9 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
Non-firm Sales
Schedule Page: 310.1 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 13 Column: b
ISDA Master Agreement with JP Morgan Chase Bank dated November 4, 2005
Schedule Page: 310.2 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 3 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000
Schedule Page: 310.2 Line No.: 4 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 8 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 14 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: b
Prudential Bache Commodities, LLC Futures Account Document, dated September 4, 2008
Schedule Page: 310.3 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 12 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 14 Column: b
Non-firm Sales
Schedule Page: 310.4 Line No.: 2 Column: b

ISDA Master Agreement with Sempra dated February 21, 2008

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

Financial Transmission Losses

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

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

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

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 7 Column: b

Non-firm Sales

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

Financial Transmission Losses

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

Non-firm Sales

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

Financial Transmission Losses

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Financial Transmission Losses

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Contract Expiration Date 5/31/2013

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,888,571	1,814,867
5	(501) Fuel	146,926,801	130,234,531
6	(502) Steam Expenses	7,337,561	7,434,710
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,140,193	2,568,382
10	(506) Miscellaneous Steam Power Expenses	9,797,755	8,111,562
11	(507) Rents	229,315	514,732
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	168,320,196	150,678,784
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,292,767	2,072,391
16	(511) Maintenance of Structures	309,374	487,528
17	(512) Maintenance of Boiler Plant	16,067,832	13,675,892
18	(513) Maintenance of Electric Plant	3,915,291	3,595,301
19	(514) Maintenance of Miscellaneous Steam Plant	3,753,015	4,639,081
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	26,338,279	24,470,193
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	194,658,475	175,148,977
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,362,099	5,242,496
45	(536) Water for Power	7,322,751	7,174,597
46	(537) Hydraulic Expenses	10,671,807	10,093,906
47	(538) Electric Expenses	1,565,842	1,470,715
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,895,723	2,686,753
49	(540) Rents	406,432	376,849
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	28,224,654	27,045,316
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,967,876	2,072,103
54	(542) Maintenance of Structures	1,155,653	1,396,815
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,368,190	1,132,574
56	(544) Maintenance of Electric Plant	3,177,811	2,962,850
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,029,473	2,971,583
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,699,003	10,535,925
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	38,923,657	37,581,241

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	328,417	347,933
63	(547) Fuel	12,745,952	19,331,689
64	(548) Generation Expenses	448,744	405,013
65	(549) Miscellaneous Other Power Generation Expenses	450,180	320,014
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,973,293	20,404,649
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	43	
70	(552) Maintenance of Structures	182,043	194,110
71	(553) Maintenance of Generating and Electric Plant	118,533	524,579
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,077,264	1,710,504
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,377,883	2,429,193
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	15,351,176	22,833,842
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	137,850,336	160,569,065
77	(556) System Control and Load Dispatching	160	13,142
78	(557) Other Expenses	53,795,016	69,383,801
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	191,645,512	229,966,008
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	440,578,820	465,530,068
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,992,955	2,534,092
84	(561) Load Dispatching	273,869	169,190
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,254,735	1,348,929
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,316,482	994,682
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	108,008	101,790
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,987,214	1,946,068
94	(563) Overhead Lines Expenses	660,035	907,200
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,918,507	6,628,695
97	(566) Miscellaneous Transmission Expenses	336,835	386,603
98	(567) Rents	1,569,168	1,564,349
99	TOTAL Operation (Enter Total of lines 83 thru 98)	16,417,808	16,581,598
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	540,340	590,179
102	(569) Maintenance of Structures	195	
103	(569.1) Maintenance of Computer Hardware	66,482	82,703
104	(569.2) Maintenance of Computer Software	324,033	268,304
105	(569.3) Maintenance of Communication Equipment	28,510	32,141
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,447,662	2,999,666
108	(571) Maintenance of Overhead Lines	2,781,256	2,936,203
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	-40	38
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,188,438	6,909,234
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,606,246	23,490,832

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,713,391	3,357,224
135	(581) Load Dispatching	3,419,960	3,186,033
136	(582) Station Expenses	1,277,818	1,136,350
137	(583) Overhead Line Expenses	3,029,340	3,446,690
138	(584) Underground Line Expenses	1,792,342	1,915,974
139	(585) Street Lighting and Signal System Expenses	79,537	134,828
140	(586) Meter Expenses	4,219,270	4,473,033
141	(587) Customer Installations Expenses	1,521,427	1,331,636
142	(588) Miscellaneous Expenses	5,004,179	5,003,459
143	(589) Rents	440,788	308,806
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,498,052	24,294,033
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	371,979	310,403
147	(591) Maintenance of Structures	-11,385	25,089
148	(592) Maintenance of Station Equipment	3,774,723	3,354,447
149	(593) Maintenance of Overhead Lines	14,297,636	14,503,170
150	(594) Maintenance of Underground Lines	1,003,405	1,083,316
151	(595) Maintenance of Line Transformers	448,157	410,917
152	(596) Maintenance of Street Lighting and Signal Systems	587,953	501,683
153	(597) Maintenance of Meters	700,080	711,387
154	(598) Maintenance of Miscellaneous Distribution Plant	137,583	267,231
155	TOTAL Maintenance (Total of lines 146 thru 154)	21,310,131	21,167,643
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,808,183	45,461,676
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	410,702	373,734
160	(902) Meter Reading Expenses	4,026,937	5,399,410
161	(903) Customer Records and Collection Expenses	12,988,731	13,096,476
162	(904) Uncollectible Accounts	4,638,855	5,268,902
163	(905) Miscellaneous Customer Accounts Expenses	342	556
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	22,065,567	24,139,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	352,779	258,454
168	(908) Customer Assistance Expenses	51,959,849	40,754,937
169	(909) Informational and Instructional Expenses	31,517	16,116
170	(910) Miscellaneous Customer Service and Informational Expenses	864,003	840,420
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	53,208,148	41,869,927
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	63,660,597	61,677,661
182	(921) Office Supplies and Expenses	13,613,991	12,455,430
183	(Less) (922) Administrative Expenses Transferred-Credit	27,799,634	27,866,621
184	(923) Outside Services Employed	7,210,630	7,562,948
185	(924) Property Insurance	3,329,577	3,262,112
186	(925) Injuries and Damages	5,668,380	6,804,103
187	(926) Employee Pensions and Benefits	30,031,098	31,049,314
188	(927) Franchise Requirements	2,549	3,196
189	(928) Regulatory Commission Expenses	3,797,836	5,298,808
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	417,950	158,199
192	(930.2) Miscellaneous General Expenses	3,826,102	3,561,160
193	(931) Rents	12,600	1,090
194	TOTAL Operation (Enter Total of lines 181 thru 193)	103,771,676	103,967,400
195	Maintenance		
196	(935) Maintenance of General Plant	4,182,610	3,946,638
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	107,954,286	107,914,038
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	693,221,250	708,405,619

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Willis and Betty Deveny/Shinglecreek	LU	-	N/A	N/A	N/A
2	James B. Howell / CHI Elkcreek	LU	-	N/A	N/A	N/A
3	Tamarack Energy Partnership	LU	-	4.942Mw		
4	Owyhee Irrigation District					
5	Mitchell Butte	LU	-	N/A	N/A	N/A
6	Owyhee Dam	LU	-	N/A	N/A	N/A
7	Tunnel #1	LU	-	N/A	N/A	N/A
8	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
9	Clifton E. Jenson/Birchcreek	LU	-	.05Mw		
10	Snake River Pottery	LU	-	N/A	N/A	N/A
11	White Water Ranch	LU	-	N/A	N/A	N/A
12	John R LeMoyne	LU	-	N/A	N/A	N/A
13	David R Snedigar	LU	-	N/A	N/A	N/A
14	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
945				65,888		65,888	1
3,453				244,156		244,156	2
33,348			1,576,498	1,257,000		2,833,498	3
							4
5,386				123,771		123,771	5
17,676				332,668		332,668	6
6,473				642,682		642,682	7
1,184				86,901		86,901	8
341			17,500	9,639		27,139	9
398				26,663		26,663	10
692				46,402		46,402	11
644				35,619		35,619	12
1,571				108,951		108,951	13
415				28,007		28,007	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Rim View Trout Company	OS	-	N/A	N/A	N/A
2	Curry Cattle Company	LU	-	.084Mw		
3	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
4	Big Wood Canal Company					
5	Black Canyon	LU	-	N/A	N/A	N/A
6	Jim Knight	LU	-	N/A	N/A	N/A
7	Sagebrush	LU	-	N/A	N/A	N/A
8	Fisheries Development	OS	-	N/A	N/A	N/A
9	Shorock Hydro Inc.					
10	Shoshone Cspp	LU	-	N/A	N/A	N/A
11	Shoshone #2	LU	-	N/A	N/A	N/A
12	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
13	Richard Kaster					
14	Box Canyon	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,167				26,174		26,174	1
582			26,796	16,479		43,275	2
829				57,475		57,475	3
							4
299				20,284		20,284	5
762				52,124		52,124	6
1,079				75,805		75,805	7
1,028				24,540		24,540	8
							9
1,791				141,782		141,782	10
2,245				150,927		150,927	11
8,473			552,508	239,707		792,215	12
							13
1,973				129,702		129,702	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Briggs Creek	LU	-	N/A	N/A	N/A
2	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
3	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
4	Allan Ravenscroft/Malad River	LU	-	.488Mw		
5	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
6	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
7	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
8	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
9	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
10	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
11	Pigeon Cove Power	LU	-	1.389		
12	Consolidated Hydro Inc. / Enel		-			
13	Barber Dam	LU		N/A	N/A	N/A
14	GeoBon #2	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,325				225,841		225,841	1
856				20,233		20,233	2
1,478				107,017		107,017	3
2,498			155,672	70,656		226,328	4
3,822				281,612		281,612	5
3,413				287,697		287,697	6
3,286				268,031		268,031	7
3,802				291,667		291,667	8
8,729				571,411		571,411	9
10,197				694,883		694,883	10
8,486			486,150	208,757		694,907	11
							12
11,010				565,629		565,629	13
3,458				253,598		253,598	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Rock Creek #2	LU	-	N/A	N/A	N/A
2	Dietrich Drop	LU	-	N/A	N/A	N/A
3	Lowline #2	LU	-	N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
6	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
7	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
10	Bypass Limited	LU	-	N/A	N/A	N/A
11	SE Hazelton A LP	LU	-	N/A	N/A	N/A
12	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
13	J R Simplot Co.	LU	-	N/A	N/A	N/A
14	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
7,509				387,612		387,612	1
13,986				766,859		766,859	2
9,855				522,921		522,921	3
5,800				372,404		372,404	4
27,454				1,967,031		1,967,031	5
5,371				397,873		397,873	6
3,120				207,505		207,505	7
3,565				267,609		267,609	8
15,562				857,911		857,911	9
26,217				1,408,365		1,408,365	10
23,215				1,190,424		1,190,424	11
1,395				105,830		105,830	12
79,349				4,439,681		4,439,681	13
4,438				395,444		395,444	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	City of Hailey	LU	-	N/A	N/A	N/A
2	City of Pocatello	LU	-	N/A	N/A	N/A
3	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
4	Wilson Power Company	LU	-	N/A	N/A	N/A
5	Hazelton B Power Company	LU	-	N/A	N/A	N/A
6	Pristine Springs Inc. #1	LU	-	N/A	N/A	N/A
7	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
8	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
9	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
10	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
11	Glenns Ferry Cogeneration Partners/Mag	LU	-	N/A	N/A	N/A
12	Tasco - Nampa	OS	-	N/A	N/A	N/A
13	Pristine Springs Inc # 3	LU	-	N/A	N/A	N/A
14	Ted S. Sorenson/Tiber Dam	LU		N/A	N/A	N/A
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
39				2,705		2,705	1
1,293				92,531		92,531	2
41,414				2,670,436		2,670,436	3
25,964				1,807,885		1,807,885	4
22,235				1,548,494		1,548,494	5
835				46,508		46,508	6
							7
38,154				2,598,307		2,598,307	8
4,508				305,862		305,862	9
78,992				5,069,998		5,069,998	10
							11
262				4,479		4,479	12
1,284				66,708		66,708	13
28,821				1,438,662		1,438,662	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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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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	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
2	G2 Energy Hidden Hollow	LU		N/A	N/A	N/A
3	Horseshoe Bend Wind/United Materials	LU		N/A	N/A	N/A
4	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
5	Riverside Hydro Mora Drop	LU		N/A	N/A	N/A
6	J.M. Miller/Sahko Hydro	LU		N/A	N/A	N/A
7	D.R. Johnson Lumber/Co Gen Co	SF		N/A	N/A	N/A
8	Twin Falls Energy/Lowline Midway Hydro	LU		N/A	N/A	N/A
9	Bennett Creek Wind Farm	LU		N/A	N/A	N/A
10	Bettencourt DryCreek Biofactory	LU		N/A	N/A	N/A
11	Big Sky Dairy Digester	LU		N/A	N/A	N/A
12	Hot Springs Wind Farm	LU		N/A	N/A	N/A
13	Tuana Springs Expansion	LU		N/A	N/A	N/A
14	Cassia Wind Farm	LU		N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
28,333				1,374,146		1,374,146	1
23,085				1,265,412		1,265,412	2
12,714				657,912		657,912	3
-3							4
4,813				264,650		264,650	5
1,231				23,161		23,161	6
18,907				996,937		996,937	7
8,798				540,236		540,236	8
29,892				1,709,391		1,709,391	9
12,726				749,161		749,161	10
9,894				616,378		616,378	11
30,982				1,765,372		1,765,372	12
54,767				3,422,518		3,422,518	13
26,081				1,246,885		1,246,885	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Riverside Investments/Arena Drop	LU		N/A	N/A	N/A
2	Cargill Inc./B6 Anaerobic Digester	LU		N/A	N/A	N/A
3	Cassia Gulch Wind Park	LU		N/A	N/A	N/A
4	New Wind Projects Scheduled Energy	LU		N/A	N/A	N/A
5	Other Purchased Power					
6	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
7	Avista Corp.	SF	T-12	N/A	N/A	N/A
8	Avista Corp.	SF	WSPP	N/A	N/A	N/A
9	Avista Corp.	OS	WSPP	N/A	N/A	N/A
10	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
11	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
12	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
13	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
14	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
509				21,086		21,086	1
1,699				33,772		33,772	2
16,979				739,555		739,555	3
1,271							4
							5
28,414				1,010,208		1,010,208	6
130				4,392		4,392	7
7,580				276,400		276,400	8
					246,160	246,160	9
21,600				798,256		798,256	10
1,316				44,840		44,840	11
540				16,350		16,350	12
983				33,804		33,804	13
					538,370	538,370	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
77,785				2,798,009		2,798,009	1
33,002				1,736,670		1,736,670	2
1,725							3
4,002				158,866		158,866	4
144,480				6,598,419		6,598,419	5
741				29,761		29,761	6
19,631				718,402		718,402	7
10							8
385				14,973		14,973	9
1,200				36,100		36,100	10
805				26,538		26,538	11
28,600				723,584		723,584	12
415				4,891		4,891	13
11,750				372,108		372,108	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Endure Energy, LLC	SF	WSPP	N/A	N/A	N/A
2	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
3	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
4	IBERDROLA RENEWABLES, Inc.	OS	WSPP	N/A	N/A	N/A
5	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
6	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
7	JPMorgan Chase Bank, N.A.	OS		N/A	N/A	N/A
8	Macquarie Cook Power Inc.	SF	WSPP	N/A	N/A	N/A
9	Morgan Stanley Capital Group Inc.	OS	-	N/A	N/A	N/A
10	Morgan Stanley Capital Group Inc.	SF	WSPP	N/A	N/A	N/A
11	NextEra Energy Power Marketing, LLC	SF	WSPP	N/A	N/A	N/A
12	NorthPoint Energy Solutions Inc.	SF	WSPP	N/A	N/A	N/A
13	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
14	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
800				33,000		33,000	1
38,575				814,201		814,201	2
5,622				147,780		147,780	3
27				-270		-270	4
55,375				1,302,472		1,302,472	5
3,600				132,992		132,992	6
					229,972	229,972	7
57,482				2,197,247		2,197,247	8
					912,802	912,802	9
9,512				341,406		341,406	10
480				20,271		20,271	11
625				19,000		19,000	12
142				4,839		4,839	13
290				8,075		8,075	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Pacific Northwest Generating Cooperati	SF	WSPP	N/A	N/A	N/A
2	PacifiCorp Inc.	SF	T-13	N/A	N/A	N/A
3	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
4	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
5	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
6	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
7	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
8	PPL EnergyPlus, LLC	IF	WSPP	N/A	N/A	N/A
9	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
10	Prudential Bache Commodities, LLC	OS		N/A	N/A	N/A
11	Prudential Bache Commodities, LLC	AD	-	N/A	N/A	N/A
12	Public Service Company of Colorado	SF	WSPP	N/A	N/A	N/A
13	Public Service Company of New Mexico	SF	WSPP	N/A	N/A	N/A
14	Puget Sound Energy, Inc.	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
400				4,200		4,200	1
715				24,013		24,013	2
11,557				425,780		425,780	3
					221,600	221,600	4
226				7,576		7,576	5
30,076				1,111,020		1,111,020	6
50,522				2,936,591		2,936,591	7
103,584				9,555,624		9,555,624	8
85,792				2,546,937		2,546,937	9
					8,907,322	8,907,322	10
					5,904	5,904	11
5,600				195,200		195,200	12
1,359				49,064		49,064	13
100				500		500	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
3	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
4	Sacramento Municipal Utility District	SF	WSPP	N/A	N/A	N/A
5	Salt River Project	SF	WSPP	N/A	N/A	N/A
6	Seattle City Light	SF	WSPP	N/A	N/A	N/A
7	Sempra Energy Solutions	SF	WSPP	N/A	N/A	N/A
8	Sempra Energy Trading LLC	OS		N/A	N/A	N/A
9	Sempra Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
10	Shell Energy North America (US), L.P.	OS	WSPP	N/A	N/A	N/A
11	Shell Energy North America (US), L.P.	OS		N/A	N/A	N/A
12	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
13	Sierra Pacific Power Co., dba NV Energ	SF	T-55	N/A	N/A	N/A
14	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
229				7,763		7,763	1
60,430				2,377,768		2,377,768	2
12,135				313,243		313,243	3
400				12,700		12,700	4
210				10,305		10,305	5
16,172				624,102		624,102	6
2,850				82,243		82,243	7
					1,967,180	1,967,180	8
85,003				5,036,027		5,036,027	9
100				2,700		2,700	10
					435,552	435,552	11
28,767				992,626		992,626	12
135				4,573		4,573	13
1,535				56,575		56,575	14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
2	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
3	Southern California Edison	SF	WSPP	N/A	N/A	N/A
4	Southwestern Public Service Company	SF	WSPP	N/A	N/A	N/A
5	Tacoma Power	SF	WSPP	N/A	N/A	N/A
6	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
8	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
9	Western Area Power Partners LLC	SF	WSPP	N/A	N/A	N/A
10	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
11	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
12	Net Metering Customers	OS	-	N/A	N/A	N/A
13	Oregon Solar Customers	OS		N/A	N/A	N/A
14	Power Exchanges					
	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)	
					408	408	1
16,894				591,270		591,270	2
2,025				82,364		82,364	3
41							4
3,454				130,837		130,837	5
1,333				12,733		12,733	6
2,284				62,018		62,018	7
52				2,050		2,050	8
5				154		154	9
71,846				4,141,482		4,141,482	10
313,256				16,618,093		16,618,093	11
546				43,505		43,505	12
				7		7	13
							14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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	Bonneville Power Administration	EX	-			
2	NorthWestern Energy	EX	-			
3	PacifiCorp Inc.	EX	-			
4	Puget Sound Energy, Inc.	EX	-			
5	Sierra Pacific Power Co., dba NV Energ	EX	-			
6	Utah Associated Municipal Power System	EX	-			
7	Clatskanie PUD	EX	153			
8	Sierra Pacific Power Co., dba NV Ende	EX	WSPP			
9	NorthWestern Energy	EX	WSPP			
10	Other Transactions					
11	Acct Valuation-Clatskanie PUD Exchange					
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)	
	59,996	2,165					1
		5,733					2
	109,457	272,150					3
	645						4
		9,935					5
	108						6
	77,685	54,672					7
	190,764	190,764					8
	1	1					9
							10
					927,721	927,721	11
							12
							13
							14
2,377,686	438,656	535,420	2,815,124	120,642,221	14,392,991	137,850,336	

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

Unavailable

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

Unavailable

Schedule Page: 326 Line No.: 9 Column: e

Unavailable

Schedule Page: 326 Line No.: 9 Column: f

Unavailable

Schedule Page: 326.1 Line No.: 1 Column: b

Non Firm Purchases

Schedule Page: 326.1 Line No.: 2 Column: e

Unavailable

Schedule Page: 326.1 Line No.: 2 Column: f

Unavailable

Schedule Page: 326.1 Line No.: 8 Column: b

Non Firm Purchases

Schedule Page: 326.1 Line No.: 12 Column: e

Unavailable

Schedule Page: 326.1 Line No.: 12 Column: f

Unavailable

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

Unavailable

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

Unavailable

Schedule Page: 326.2 Line No.: 11 Column: e

Unavailable

Schedule Page: 326.2 Line No.: 11 Column: f

Unavailable

Schedule Page: 326.3 Line No.: 5 Column: a

Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 3 Column: a

Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 4 Column: a

Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 5 Column: a

Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 12 Column: b

Non Firm Purchases

Schedule Page: 326.5 Line No.: 4 Column: b

Energy difference between mountain and pacific time schedules

Schedule Page: 326.6 Line No.: 4 Column: b

Energy scheduled in December 2010, booked in January 2011

Schedule Page: 326.6 Line No.: 9 Column: b

Financial Transmission Losses

Schedule Page: 326.6 Line No.: 11 Column: b

Non Firm Purchases

Schedule Page: 326.6 Line No.: 12 Column: b

Short Term Unit Contingent

Schedule Page: 326.6 Line No.: 14 Column: b

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report 2010/Q4

FOOTNOTE DATA

Financial Transmission Losses

Schedule Page: 326.7 Line No.: 3 Column: b

WECC Inadvertant Settlement

Schedule Page: 326.7 Line No.: 8 Column: b

Short Term Unit Contingent

Schedule Page: 326.8 Line No.: 4 Column: b

Non Firm Purchases

Schedule Page: 326.8 Line No.: 7 Column: b

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

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

ISDA Master Agreement with Morgan Stanley dated 03/01/2000

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

Financial Transmission Losses

Schedule Page: 326.9 Line No.: 10 Column: b

Prudential Bache Commodities, LLC Futures Account Document, dated September 4, 2008.

Schedule Page: 326.9 Line No.: 11 Column: b

2009 Correction

Schedule Page: 326.9 Line No.: 14 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 8 Column: b

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

Schedule Page: 326.10 Line No.: 10 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 11 Column: b

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

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

Financial Transmission Losses

Schedule Page: 326.11 Line No.: 10 Column: b

Unavailable

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

Schedule 84 Net Metering

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

Schedule 88 Oregon Solar

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

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

Schedule Page: 326.12 Line No.: 4 Column: b

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

Schedule Page: 326.12 Line No.: 6 Column: b

Scheduled losses not removed with loss transactions.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OTEC			AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
4	Bonneville Power Administration - USBR			AD
5	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Electric Co-op	FNO
6	Bonneville Power Administration - Raft			AD
7	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
8	Bonneville Power Administration - PF			AD
9	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
10	Cargill	Seattle City Light	Bonneville Power Administration	OS
11	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
12	PacifiCorp			AD
13	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
14	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
15	Black Hills Power	Bonneville Power Administration	PacifiCorp West	NF
16	Black Hills Power			AD
17	Black Hills Power			AD
18	BPA Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
19	BPA Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
20	BPA Power Administration	Bonneville Power Administration	Sierra Pacific Power	SFP
21	BPA Power Administration	Avista	Bonneville Power Administration	NF
22	BPA Power Administration	Avista	Bonneville Power Administration	SFP
23	BPA Power Administration	Avista	Sierra Pacific Power	NF
24	BPA Power Administration	Avista	Sierra Pacific Power	SFP
25	BPA Power Administration			AD
26	BPA Power Administration			AD
27	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
29	Cargill Power Markets	PacifiCorp East	PacifiCorp West	NF
30	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
31	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	NF
32	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	SFP
33	Cargill Power Markets	PacifiCorp East	Avista	NF
34	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5			[redacted]	371,403	371,403	1
5			[redacted]			2
5			[redacted]	194,289	194,289	3
5			[redacted]			4
5			[redacted]	239,010	239,010	5
5			[redacted]			6
5			[redacted]	833,606	833,606	7
5			[redacted]			8
Legacy	Minidoka, Idaho	Various in Idaho	[redacted]	8,383	8,383	9
10			[redacted]	135,094	135,094	10
5			[redacted]	2,071	2,071	11
5			[redacted]			12
Legacy	LaGrande, Oregon	Various in Idaho	[redacted]	16,632	16,632	13
5	JBSN	LAGRANDE		1,008	1,008	14
5	LAGRANDE	JBSN		699	699	15
5			[redacted]			16
5			[redacted]			17
5	LAGRANDE	LAGRANDE		1,387	1,387	18
5	LAGRANDE	M345		904	904	19
5	LAGRANDE	M345		1,096	1,096	20
5	LOLO	LAGRANDE		2,310	2,310	21
5	LOLO	LAGRANDE		12,444	12,444	22
5	LOLO	M345		671	671	23
5	LOLO	M345		978	978	24
5			[redacted]			25
5			[redacted]			26
5	BORA	BPAT.NWMT		1,789	1,789	27
5	BORA	BPAT.NWMT		708	708	28
5	BORA	ENPR		132	132	29
5	BORA	JEFF		269	269	30
5	BORA	LAGRANDE		11,757	11,757	31
5	BORA	LAGRANDE		33,659	33,659	32
5	BORA	LOLO		2,139	2,139	33
5	BORA	M345		2,950	2,950	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	SFP
2	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
3	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
4	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
5	Cargill Power Markets	NorthWestern/PacifiCorp East	Avista	NF
6	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
8	Cargill Power Markets	PacifiCorp East	PacifiCorp East	NF
9	Cargill Power Markets	PacifiCorp East	PacifiCorp East	SFP
10	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	NF
11	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	SFP
12	Cargill Power Markets	PacifiCorp East	Avista	NF
13	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	NF
14	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	SFP
15	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
16	Cargill Power Markets	PacifiCorp West	PacifiCorp East	SFP
17	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
18	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
19	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
20	Cargill Power Markets	PacifiCorp West	PacifiCorp East	SFP
21	Cargill Power Markets	PacifiCorp West	NorthWestern/PacifiCorp East	NF
22	Cargill Power Markets	PacifiCorp West	NorthWestern/PacifiCorp East	SFP
23	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
24	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	NF
25	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	SFP
26	Cargill Power Markets	PacifiCorp West	Avista	NF
27	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
28	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	SFP
29	Cargill Power Markets	PacifiCorp West	NorthWestern/PacifiCorp East	SFP
30	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
31	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
32	Cargill Power Markets	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
33	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	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	04/15/2011	End of 2010/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	BORA	M345		3,203	3,203	1
5	BORA	AVAT.NWMT		400	400	2
5	BPAT.NWMT	BORA		651	651	3
5	BPAT.NWMT	BORA		5,540	5,540	4
5	BPAT.NWMT	LOLO		56	56	5
5	BPAT.NWMT	M345		3,233	3,233	6
5	BPAT.NWMT	M345		16,518	16,518	7
5	BRDY	BORA		2,548	2,548	8
5	BRDY	BORA		400	400	9
5	BRDY	LAGRANDE		253	253	10
5	BRDY	LAGRANDE		1,699	1,699	11
5	BRDY	LOLO		409	409	12
5	BRDY	M345		551	551	13
5	BRDY	M345		1,968	1,968	14
5	ENPR	BORA		18,253	18,253	15
5	ENPR	BORA		1,616	1,616	16
5	ENPR	JBSN		800	800	17
5	ENPR	M345		10,990	10,990	18
5	JBSN	BORA		416	416	19
5	JBSN	BORA		317	317	20
5	JBSN	BPAT.NWMT		330	330	21
5	JBSN	BPAT.NWMT		91	91	22
5	JBSN	ENPR		625	625	23
5	JBSN	LAGRANDE		2,575	2,575	24
5	JBSN	LAGRANDE		892	892	25
5	JBSN	LOLO		312	312	26
5	JBSN	M345		1,208	1,208	27
5	JBSN	M345		208	208	28
5	JBSN	AVAT.NWMT		32	32	29
5	JEFF	BORA		32	32	30
5	JEFF	BORA		400	400	31
5	JEFF	LAGRANDE		79	79	32
5	JEFF	M345		2,855	2,855	33
5	JEFF	M345		258	258	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5	LAGRANDE	BORA		1,269	1,269	1
5	LAGRANDE	BRDY		34	34	2
5	LAGRANDE	JBSN		120	120	3
5	LAGRANDE	LOLO		65	65	4
5	LAGRANDE	M345		14,567	14,567	5
5	LAGRANDE	M345		3,484	3,484	6
5	LOLO	BORA		18,886	18,886	7
5	LOLO	BORA		2,808	2,808	8
5	LOLO	M345		11,357	11,357	9
5	LOLO	M345		1,166	1,166	10
5	LYPK	BORA		3,861	3,861	11
5	LYPK	BORA		16,193	16,193	12
5	LYPK	BPAT.NWMT		355	355	13
5	LYPK	BPAT.NWMT		132	132	14
5	LYPK	IPCO		48	48	15
5	LYPK	LAGRANDE		47,965	47,965	16
5	LYPK	LAGRANDE		15,151	15,151	17
5	LYPK	LOLO		188	188	18
5	LYPK	M345		18,038	18,038	19
5	LYPK	M345		179,321	179,321	20
5	M345	BORA		768	768	21
5	M345	BORA		32	32	22
5	M345	IPCO		25	25	23
5	M345	LAGRANDE		3,546	3,546	24
5	M345	LOLO		144	144	25
5	OBBLPR	LAGRANDE		400	400	26
5	OBBLPR	M345		238	238	27
5						28
5						29
5						30
5						31
5						32
5						33
5						34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	BORA	LAGRANDE		957	957	1
5	LAGRANDE	BORA		386	386	2
5						3
5						4
5						5
5	BPAT.NWMT	M345		75	75	6
5	LAGRANDE	BORA		946	946	7
5	LAGRANDE	BRDY		53	53	8
5	LAGRANDE	M345		241	241	9
5						10
5	BORA	BPAT.NWMT		80	80	11
5	BORA	M345		1,617	1,617	12
5	BORA	M345		623	623	13
5	BPAT.NWMT	BRDY		45	45	14
5	BPAT.NWMT	LAGRANDE		806	806	15
5	BRDY	BPAT.NWMT		44	44	16
5	BRDY	JEFF		45	45	17
5	BRDY	LAGRANDE		30,482	30,482	18
5	BRDY	LAGRANDE		215	215	19
5	BRDY	LOLO		2,571	2,571	20
5	BRDY	M345		352	352	21
5	BRDY	AVAT.NWMT		18	18	22
5	ENPR	BRDY		2,687	2,687	23
5	ENPR	M345		315	315	24
5	JBSN	BPAT.NWMT		10	10	25
5	JBSN	LAGRANDE		127	127	26
5	JBWT	LAGRANDE		445	445	27
5	JEFF	LAGRANDE		5,007	5,007	28
5	JEFF	LOLO		360	360	29
5	JEFF	M345		52	52	30
5	JEFF	GSHN		25	25	31
5	LAGRANDE	BORA		314	314	32
5	LAGRANDE	BRDY		4,411	4,411	33
5	LAGRANDE	M345		2,667	2,667	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Avista	PacifiCorp East	NF
2	Morgan Stanley Capital Group	Avista	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group	Avista	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group	Sierra Pacific Power	PacifiCorp East	NF
5	Morgan Stanley Capital Group	Sierra Pacific Power	PacifiCorp West	NF
6	Morgan Stanley Capital Group	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
7	Morgan Stanley Capital Group	Sierra Pacific Power	Bonneville Power Administration	NF
8	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
10	Morgan Stanley Capital Group			AD
11	Morgan Stanley Capital Group			AD
12	Northwestern Energy	PacifiCorp East	Bonneville Power Administration	NF
13	Northwestern Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
14	Northwestern Energy			AD
15	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
16	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
17	Pacificorp Power Marketing	PacifiCorp East	Bonneville Power Administration	NF
18	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
19	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	LFP
20	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
21	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	SFP
22	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
23	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
24	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
25	Pacificorp Power Marketing	PacifiCorp West	Idaho Power Company	NF
26	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
27	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
28	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
29	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
30	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
31	Pacificorp Power Marketing	Idaho Power Company	Idaho Power Company	NF
32	Pacificorp Power Marketing	Idaho Power Company	NorthWestern/PacifiCorp East	NF
33	Pacificorp Power Marketing	Idaho Power Company	Bonneville Power Administration	NF
34	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	LOLO	BRDY		414	414	1
5	LOLO	LAGRANDE		21	21	2
5	LOLO	M345		799	799	3
5	M345	BRDY		35	35	4
5	M345	JBSN		5	5	5
5	M345	JEFF		180	180	6
5	M345	LAGRANDE		130	130	7
5	GSHN	BRDY		40	40	8
5	GSHN	LAGRANDE		235	235	9
5			[redacted]			10
5			[redacted]			11
5	BRDY	LAGRANDE		397	397	12
5	JEFF	LAGRANDE		762	762	13
5			[redacted]			14
5	BORA	ENPR		31,339	31,339	15
5	BORA	IPCO		33	33	16
5	BORA	LAGRANDE		13,680	13,680	17
5	BORA	KPRT		1,251	1,251	18
5	BORA	KPRT		108,362	108,362	19
5	BRDY	BRDY		8,702	8,702	20
5	BRDY	BRDY		726	726	21
5	BRDY	KPRT		16,320	16,320	22
5	ENPR	BORA		73,303	73,303	23
5	ENPR	BRDY		13,239	13,239	24
5	ENPR	IPCO		9,562	9,562	25
5	ENPR	M345		1,050	1,050	26
5	JBWT	BORA		29,317	29,317	27
5	JBWT	BORA		161,627	161,627	28
5	JBWT	BRDY		181,559	181,559	29
5	JBWT	ENPR		56,964	56,964	30
5	JBWT	IPCO		564	564	31
5	JBWT	JEFF		50	50	32
5	JBWT	LAGRANDE		17,568	17,568	33
5	JBWT	M500		31,591	31,591	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	LFP
2	Pacificorp Power Marketing	Bonneville Power Administration	PacifiCorp East	NF
3	Pacificorp Power Marketing	Bonneville Power Administration	PacifiCorp East	NF
4	Pacificorp Power Marketing	Avista	PacifiCorp West	NF
5	Pacificorp Power Marketing			AD
6	Pacificorp Power Marketing			AD
7	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
8	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Portland General Electric			AD
10	Portland General Electric			AD
11	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
12	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
14	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
15	Powerex Corporation	PacifiCorp East	Avista	NF
16	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
17	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
19	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
21	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
22	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
23	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	SFP
24	Powerex Corporation	PacifiCorp East	Avista	NF
25	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
26	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
27	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
28	Powerex Corporation	PacifiCorp West	PacifiCorp East	SFP
29	Powerex Corporation	PacifiCorp West	PacifiCorp West	NF
30	Powerex Corporation	PacifiCorp West	Bonneville Power Administration	NF
31	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
32	Powerex Corporation	PacifiCorp West	NorthWestern/PacifiCorp East	NF
33	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
34	Powerex Corporation	PacifiCorp West	PacifiCorp West	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	04/15/2011	End of 2010/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	JBWT	M500		929,005	929,005	1
5	LAGRANDE	BORA		3,670	3,670	2
5	LAGRANDE	BRDY		320	320	3
5	LOLO	ENPR		1,624	1,624	4
5						5
5						6
5	BRDY	LAGRANDE		2	2	7
5	JEFF	LAGRANDE		200	200	8
5						9
5						10
5	BORA	BPAT.NWMT		132	132	11
5	BORA	BRDY		349	349	12
5	BORA	ENPR		265	265	13
5	BORA	LAGRANDE		41,295	41,295	14
5	BORA	LOLO		15	15	15
5	BORA	M345		33	33	16
5	BPAT.NWMT	BRDY		472	472	17
5	BPAT.NWMT	LAGRANDE		1,157	1,157	18
5	BPAT.NWMT	M345		399	399	19
5	BRDY	BPAT.NWMT		59	59	20
5	BRDY	ENPR		9,180	9,180	21
5	BRDY	LAGRANDE		35,437	35,437	22
5	BRDY	LAGRANDE		2,446	2,446	23
5	BRDY	LOLO		78	78	24
5	BRDY	M345		642	642	25
5	ENPR	BORA		3,570	3,570	26
5	ENPR	BRDY		64,068	64,068	27
5	ENPR	BRDY		13,839	13,839	28
5	ENPR	JBSN		129	129	29
5	ENPR	LAGRANDE		2,664	2,664	30
5	ENPR	M345		1,766	1,766	31
5	JBSN	BPAT.NWMT		333	333	32
5	JBSN	BRDY		20	20	33
5	JBSN	ENPR		54	54	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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).
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4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corporation	PacifiCorp West	NorthWestern/PacifiCorp East	NF
2	Powerex Corporation	PacifiCorp West	Bonneville Power Administration	NF
3	Powerex Corporation	PacifiCorp West	Avista	NF
4	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
5	Powerex Corporation	Idaho Power Company	PacifiCorp West	NF
6	Powerex Corporation	Idaho Power Company	Bonneville Power Administration	NF
7	Powerex Corporation	Idaho Power Company	Avista	NF
8	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Powerex Corporation	NorthWestern/PacifiCorp East	Avista	NF
10	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
11	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
12	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
13	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	SFP
14	Powerex Corporation	Bonneville Power Administration	PacifiCorp West	NF
15	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
16	Powerex Corporation	Avista	PacifiCorp East	NF
17	Powerex Corporation	Avista	PacifiCorp East	NF
18	Powerex Corporation	Avista	Bonneville Power Administration	NF
19	Powerex Corporation	Avista	Sierra Pacific Power	NF
20	Powerex Corporation	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
21	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
22	Powerex Corporation	Sierra Pacific Power	PacifiCorp West	NF
23	Powerex Corporation	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
24	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
25	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
26	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
27	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp West	NF
28	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp West	NF
29	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
30	Powerex Corporation			AD
31	Powerex Corporation			AD
32	PPL EnergyPlus, LLC	PacifiCorp East	NorthWestern/PacifiCorp East	NF
33	PPL EnergyPlus, LLC	PacifiCorp East	Bonneville Power Administration	NF
34	PPL EnergyPlus, LLC	PacifiCorp East	Avista	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	04/15/2011	End of 2010/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	JBSN	JEFF		54	54	1
5	JBSN	LAGRANDE		8,338	8,338	2
5	JBSN	LOLO		23	23	3
5	JBWT	BRDY		154	154	4
5	JBWT	ENPR		10	10	5
5	JBWT	LAGRANDE		3,762	3,762	6
5	JBWT	LOLO		150	150	7
5	JEFF	LAGRANDE		3,528	3,528	8
5	JEFF	LOLO		11	11	9
5	JEFF	M345		50	50	10
5	LAGRANDE	BORA		6,267	6,267	11
5	LAGRANDE	BRDY		4,662	4,662	12
5	LAGRANDE	BRDY		280	280	13
5	LAGRANDE	JBSN		1,258	1,258	14
5	LAGRANDE	M345		6,262	6,262	15
5	LOLO	BORA		248	248	16
5	LOLO	BRDY		1,892	1,892	17
5	LOLO	LAGRANDE		1,600	1,600	18
5	LOLO	M345		313	313	19
5	M345	BPAT.NWMT		10	10	20
5	M345	BRDY		155	155	21
5	M345	ENPR		150	150	22
5	M345	JEFF		37	37	23
5	M345	LAGRANDE		2,940	2,940	24
5	AVAT.NWMT	BORA		129	129	25
5	GSHN	BRDY		100	100	26
5	GSHN	ENPR		132	132	27
5	GSHN	JBSN		30	30	28
5	GSHN	LAGRANDE		2,354	2,354	29
5						30
5						31
5	BRDY	BPAT.NWMT		15	15	32
5	BRDY	LAGRANDE		24,028	24,028	33
5	BRDY	LOLO		932	932	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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 EnergyPlus, LLC	PacifiCorp East	Avista	SFP
2	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Avista	NF
4	PPL EnergyPlus, LLC	Avista	PacifiCorp East	NF
5	PPL EnergyPlus, LLC	Avista	Sierra Pacific Power	NF
6	PPL EnergyPlus, LLC	PacifiCorp East	Avista	SFP
7	PPL EnergyPlus, LLC			AD
8	PPL EnergyPlus, LLC			AD
9	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF
10	Puget Sound Energy	PacifiCorp East	Avista	NF
11	Puget Sound Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
12	Puget Sound Energy	Sierra Pacific Power	Bonneville Power Administration	NF
13	Puget Sound Energy			AD
14	Puget Sound Energy			AD
15	Rainbow Energy Marketing Company	PacifiCorp East	Avista	NF
16	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	NF
17	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
18	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
19	Rainbow Energy Marketing Company	PacifiCorp East	Bonneville Power Administration	NF
20	Rainbow Energy Marketing Company	PacifiCorp East	Avista	NF
21	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	NF
22	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	SFP
23	Rainbow Energy Marketing Company	PacifiCorp West	NorthWestern/PacifiCorp East	SFP
24	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
26	Rainbow Energy Marketing Company	Bonneville Power Administration	Sierra Pacific Power	NF
27	Rainbow Energy Marketing Company	Avista	PacifiCorp East	NF
28	Rainbow Energy Marketing Company	Avista	PacifiCorp East	SFP
29	Rainbow Energy Marketing Company	Avista	Sierra Pacific Power	NF
30	Rainbow Energy Marketing Company	Avista	Sierra Pacific Power	SFP
31	Rainbow Energy Marketing Company	Sierra Pacific Power	Avista	NF
32	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
33	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	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	04/15/2011	End of 2010/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	BRDY	LOLO		1,080	1,080	1
5	JEFF	LAGRANDE		7,251	7,251	2
5	JEFF	LOLO		1,277	1,277	3
5	LOLO	BRDY		15	15	4
5	LOLO	M345		1,136	1,136	5
5	MLCK	LOLO		1,104	1,104	6
5						7
5						8
5	BRDY	LAGRANDE		17,782	17,782	9
5	BRDY	LOLO		5	5	10
5	JEFF	LAGRANDE		117	117	11
5	M345	LAGRANDE		180	180	12
5						13
5						14
5	BORA	LOLO		400	400	15
5	BORA	M345		400	400	16
5	BPAT.NWMT	M345		40	40	17
5	BPAT.NWMT	M345		720	720	18
5	BRDY	LAGRANDE		330	330	19
5	BRDY	LOLO		50	50	20
5	BRDY	M345		7,523	7,523	21
5	BRDY	M345		29,800	29,800	22
5	JBSN	JEFF		768	768	23
5	JEFF	M345		1,512	1,512	24
5	JEFF	M345		800	800	25
5	LAGRANDE	M345		1,329	1,329	26
5	LOLO	BORA		1,320	1,320	27
5	LOLO	BORA		12,384	12,384	28
5	LOLO	M345		4,039	4,039	29
5	LOLO	M345		2,995	2,995	30
5	M345	LOLO		6	6	31
5	AVAT.NWMT	BRDY		400	400	32
5	AVAT.NWMT	M345		600	600	33
5	AVAT.NWMT	M345		600	600	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Rainbow Energy Marketing Company			AD
2	Rainbow Energy Marketing Company			AD
3	Seattle City Light			LFP
4	Seattle City Light			AD
5	Sempra Energy			AD
6	Sempra Energy			AD
7	Shell Energy North America	PacifiCorp East	Bonneville Power Administration	NF
8	Shell Energy North America	PacifiCorp East	Bonneville Power Administration	NF
9	Shell Energy North America	PacifiCorp East	Sierra Pacific Power	NF
10	Shell Energy North America	PacifiCorp West	Bonneville Power Administration	NF
11	Shell Energy North America	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
12	Shell Energy North America	NorthWestern/PacifiCorp East	Avista	NF
13	Shell Energy North America	Bonneville Power Administration	Sierra Pacific Power	NF
14	Shell Energy North America	Sierra Pacific Power	Bonneville Power Administration	NF
15	Shell Energy North America	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
16	Shell Energy North America	Sierra Pacific Power	PacifiCorp East	NF
17	Shell Energy North America	Sierra Pacific Power	Bonneville Power Administration	NF
18	Shell Energy North America	Idaho Power Company	Bonneville Power Administration	NF
19	Shell Energy North America	Idaho Power Company	Bonneville Power Administration	NF
20	Shell Energy North America			AD
21	Shell Energy North America			AD
22	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
24	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	SFP
25	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
26	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
27	Sierra Pacific Power	Bonneville Power Administration	Sierra Pacific Power	NF
28	Sierra Pacific Power	Bonneville Power Administration	Sierra Pacific Power	SFP
29	Sierra Pacific Power	Avista	Sierra Pacific Power	NF
30	Sierra Pacific Power	Avista	Sierra Pacific Power	SFP
31	Sierra Pacific Power	Sierra Pacific Power	PacifiCorp East	NF
32	Sierra Pacific Power	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
33	Sierra Pacific Power	Sierra Pacific Power	Bonneville Power Administration	NF
34	Sierra Pacific Power	Sierra Pacific Power	Avista	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5						1
5						2
5						3
5						4
5						5
5						6
5	BORA	LAGRANDE		352	352	7
5	BRDY	LAGRANDE		7,507	7,507	8
5	BRDY	M345		784	784	9
5	JBSN	LAGRANDE		64	64	10
5	JEFF	LAGRANDE		1,262	1,262	11
5	JEFF	LOLO		70	70	12
5	LAGRANDE	M345		5,687	5,687	13
5	LYPK	LAGRANDE		633	633	14
5	M345	BPAT.NWMT		25	25	15
5	M345	BRDY		65	65	16
5	M345	LAGRANDE		5,937	5,937	17
5	MDSK	LAGRANDE		88	88	18
5	OBBLPR	LAGRANDE		155	155	19
5						20
5						21
5	BPAT.NWMT	M345		264	264	22
5	BRDY	M345		14,496	14,496	23
5	BRDY	M345		11,215	11,215	24
5	JBSN	M345		146	146	25
5	JEFF	M345		713	713	26
5	LAGRANDE	M345		27,772	27,772	27
5	LAGRANDE	M345		272	272	28
5	LOLO	M345		28,510	28,510	29
5	LOLO	M345		14,071	14,071	30
5	M345	BRDY		55	55	31
5	M345	JEFF		501	501	32
5	M345	LAGRANDE		8,261	8,261	33
5	M345	LOLO		200	200	34
			0	**4,527,870**	**4,527,870**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Sierra Pacific Power			AD
2	Sierra Pacific Power			AD
3	Southernn California Edison	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
4	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
5	Transalta Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
6	Transalta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
7	Transalta Energy Marketing	PacifiCorp East	Avista	NF
8	Transalta Energy Marketing	PacifiCorp West	Bonneville Power Administration	NF
9	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
10	Transalta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
11	Transalta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
12	Transalta Energy Marketing	Avista	PacifiCorp East	NF
13	Transalta Energy Marketing	Avista	Sierra Pacific Power	NF
14	Transalta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
15	Transalta Energy Marketing	Sierra Pacific Power	Avista	NF
16	Transalta Energy Marketing			AD
17	Transalta Energy Marketing			AD
18	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
19	Utah Associated Municipal Power Systems			AD
20	Utah Associated Municipal Power Systems			AD
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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						1
5						2
5	GSHN	LAGRANDE		20	20	3
5	BORA	LAGRANDE		1,239	1,239	4
5	BPAT.NWMT	M345		75	75	5
5	BRDY	LAGRANDE		280	280	6
5	BRDY	LOLO		63	63	7
5	JBSN	LAGRANDE		600	600	8
5	LAGRANDE	BORA		474	474	9
5	LAGRANDE	BRDY		60	60	10
5	LAGRANDE	M345		712	712	11
5	LOLO	BORA		1,528	1,528	12
5	LOLO	M345		25	25	13
5	M345	LAGRANDE		477	477	14
5	M345	LOLO		10	10	15
5						16
5						17
5	BORA	M345		3,074	3,074	18
5						19
5						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**4,527,870**	**4,527,870**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,241,026	2,602		1,243,628	1
-29,701			-29,701	2
1,055,121	145,316		1,200,437	3
-13,829			-13,829	4
585,362	-81,836		503,526	5
-14,459			-14,459	6
2,354,828	-454,037		1,900,791	7
-58,373			-58,373	8
	13,581		13,581	9
	203,368		203,368	10
6,464	1,466		7,930	11
-155			-155	12
54,639			54,639	13
	2,870		2,870	14
	1,990		1,990	15
	-105		-105	16
	-22		-22	17
	4,361		4,361	18
	2,843		2,843	19
	3,446		3,446	20
	7,264		7,264	21
	39,130		39,130	22
	2,110		2,110	23
	3,075		3,075	24
	-1,727		-1,727	25
	-229		-229	26
	843		843	27
	334		334	28
	62		62	29
	127		127	30
	5,542		5,542	31
	15,866		15,866	32
	1,008		1,008	33
	1,391		1,391	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,510		1,510	1
	189		189	2
	307		307	3
	2,611		2,611	4
	26		26	5
	1,524		1,524	6
	7,786		7,786	7
	1,201		1,201	8
	189		189	9
	119		119	10
	801		801	11
	193		193	12
	260		260	13
	928		928	14
	8,604		8,604	15
	762		762	16
	377		377	17
	5,180		5,180	18
	196		196	19
	149		149	20
	156		156	21
	43		43	22
	295		295	23
	1,214		1,214	24
	420		420	25
	147		147	26
	569		569	27
	98		98	28
	15		15	29
	15		15	30
	189		189	31
	37		37	32
	1,346		1,346	33
	122		122	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

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

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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.
	598		598	1
	16		16	2
	57		57	3
	31		31	4
	6,866		6,866	5
	1,642		1,642	6
	8,902		8,902	7
	1,324		1,324	8
	5,353		5,353	9
	550		550	10
	1,820		1,820	11
	7,633		7,633	12
	167		167	13
	62		62	14
	23		23	15
	22,609		22,609	16
	7,142		7,142	17
	89		89	18
	8,503		8,503	19
	84,526		84,526	20
	362		362	21
	15		15	22
	12		12	23
	1,671		1,671	24
	68		68	25
	189		189	26
	112		112	27
	-33,126		-33,126	28
	-8,263		-8,263	29
	-2,682		-2,682	30
	-200		-200	31
	45		45	32
	-206		-206	33
	-1,194		-1,194	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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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.
	4,958		4,958	1
	2,000		2,000	2
	-530		-530	3
	-16		-16	4
	-6		-6	5
	230		230	6
	2,900		2,900	7
	162		162	8
	739		739	9
	-4		-4	10
	273		273	11
	5,519		5,519	12
	2,127		2,127	13
	154		154	14
	2,751		2,751	15
	150		150	16
	154		154	17
	104,047		104,047	18
	734		734	19
	8,776		8,776	20
	1,202		1,202	21
	61		61	22
	9,172		9,172	23
	1,075		1,075	24
	34		34	25
	434		434	26
	1,519		1,519	27
	17,091		17,091	28
	1,229		1,229	29
	177		177	30
	85		85	31
	1,072		1,072	32
	15,056		15,056	33
	9,104		9,104	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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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.
	1,413		1,413	1
	72		72	2
	2,727		2,727	3
	119		119	4
	17		17	5
	614		614	6
	444		444	7
	137		137	8
	802		802	9
	-2,161		-2,161	10
	-215		-215	11
	1,765		1,765	12
	3,387		3,387	13
	-13		-13	14
	132,821		132,821	15
	140		140	16
	57,979		57,979	17
	5,302		5,302	18
	459,260		459,260	19
	36,881		36,881	20
	3,077		3,077	21
	69,167		69,167	22
	310,673		310,673	23
	56,110		56,110	24
	40,526		40,526	25
	4,450		4,450	26
	124,251		124,251	27
	685,008		685,008	28
	769,484		769,484	29
	241,425		241,425	30
	2,390		2,390	31
	212		212	32
	74,457		74,457	33
	133,889		133,889	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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.
	3,937,311		3,937,311	1
	15,554		15,554	2
	1,356		1,356	3
	6,883		6,883	4
	-98,098		-98,098	5
	-18,231		-18,231	6
	17		17	7
	1,679		1,679	8
	-1,214		-1,214	9
	-214		-214	10
	437		437	11
	1,155		1,155	12
	877		877	13
	136,631		136,631	14
	50		50	15
	109		109	16
	1,562		1,562	17
	3,828		3,828	18
	1,320		1,320	19
	195		195	20
	30,373		30,373	21
	117,249		117,249	22
	8,093		8,093	23
	258		258	24
	2,124		2,124	25
	11,812		11,812	26
	211,979		211,979	27
	45,789		45,789	28
	427		427	29
	8,814		8,814	30
	5,843		5,843	31
	1,102		1,102	32
	66		66	33
	179		179	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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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.
	179		179	1
	27,588		27,588	2
	76		76	3
	510		510	4
	33		33	5
	12,447		12,447	6
	496		496	7
	11,673		11,673	8
	36		36	9
	165		165	10
	20,735		20,735	11
	15,425		15,425	12
	926		926	13
	4,162		4,162	14
	20,719		20,719	15
	821		821	16
	6,260		6,260	17
	5,294		5,294	18
	1,036		1,036	19
	33		33	20
	513		513	21
	496		496	22
	122		122	23
	9,727		9,727	24
	427		427	25
	331		331	26
	437		437	27
	99		99	28
	7,789		7,789	29
	-60,353		-60,353	30
	-9,282		-9,282	31
	34		34	32
	53,884		53,884	33
	2,090		2,090	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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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.
	2,422		2,422	1
	16,261		16,261	2
	2,864		2,864	3
	34		34	4
	2,548		2,548	5
	2,476		2,476	6
	-1,705		-1,705	7
	-233		-233	8
	48,736		48,736	9
	14		14	10
	321		321	11
	493		493	12
	-1,996		-1,996	13
	-84		-84	14
	887		887	15
	887		887	16
	89		89	17
	1,596		1,596	18
	731		731	19
	111		111	20
	16,675		16,675	21
	66,051		66,051	22
	1,702		1,702	23
	3,351		3,351	24
	1,773		1,773	25
	2,946		2,946	26
	2,926		2,926	27
	27,449		27,449	28
	8,952		8,952	29
	6,638		6,638	30
	13		13	31
	887		887	32
	1,330		1,330	33
	1,330		1,330	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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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.
	-7,066		-7,066	1
	-821		-821	2
	1,687,225		1,687,225	3
	-41,693		-41,693	4
	-1,801		-1,801	5
	-281		-281	6
	931		931	7
	19,855		19,855	8
	2,074		2,074	9
	169		169	10
	3,338		3,338	11
	185		185	12
	15,041		15,041	13
	1,674		1,674	14
	66		66	15
	172		172	16
	15,703		15,703	17
	233		233	18
	410		410	19
	-4,721		-4,721	20
	-324		-324	21
	650		650	22
	35,691		35,691	23
	27,613		27,613	24
	359		359	25
	1,756		1,756	26
	68,379		68,379	27
	670		670	28
	70,196		70,196	29
	34,645		34,645	30
	135		135	31
	1,234		1,234	32
	20,342		20,342	33
	492		492	34
5,180,923	**10,217,479**	**0**	**15,398,402**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

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

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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.
	-28,422		-28,422	1
	-3,558		-3,558	2
	62		62	3
	4,148		4,148	4
	251		251	5
	937		937	6
	211		211	7
	2,009		2,009	8
	1,587		1,587	9
	201		201	10
	2,384		2,384	11
	5,116		5,116	12
	84		84	13
	1,597		1,597	14
	33		33	15
	-287		-287	16
	-90		-90	17
	8,296		8,296	18
	-276		-276	19
	-25		-25	20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
5,180,923	**10,217,479**	**0**	**15,398,402**	

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

Schedule Page: 328 Line No.: 2 Column: h

OATT rate refund for periods 10/07 thru 12/09

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2014. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

OATT rate refund for periods 10/07 thru 12/09

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

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

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

OATT rate refund for periods 10/07 thru 12/09

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires December 31, 2011. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

OATT rate refund for periods 10/07 thru 12/09

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

Legacy, contract prior to the Open Access Transmission Tariff

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

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

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

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

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

The contract between Idaho Power and PacifiCorp - Imnaha expired on September 30, 2010 and was extended thru 03/31/11.

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

OATT rate refund for periods 10/07 thru 12/09

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

Legacy, contract prior to the Open Access Transmission Tariff

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

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

Schedule Page: 328 Line No.: 16 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328 Line No.: 17 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328 Line No.: 25 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328 Line No.: 26 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.2 Line No.: 28 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.2 Line No.: 29 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.2 Line No.: 30 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.2 Line No.: 31 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.2 Line No.: 33 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.2 Line No.: 34 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.3 Line No.: 3 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.3 Line No.: 4 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.3 Line No.: 5 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.3 Line No.: 10 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.4 Line No.: 10 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.4 Line No.: 11 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.4 Line No.: 14 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.5 Line No.: 5 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.5 Line No.: 6 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.5 Line No.: 9 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.5 Line No.: 10 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.6 Line No.: 30 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.6 Line No.: 31 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.7 Line No.: 7 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.7 Line No.: 8 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.7 Line No.: 13 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.7 Line No.: 14 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.8 Line No.: 1 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.8 Line No.: 2 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.8 Line No.: 4 Column: h

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OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.8 Line No.: 5 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.8 Line No.: 6 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.8 Line No.: 20 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.8 Line No.: 21 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.9 Line No.: 1 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.9 Line No.: 2 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.9 Line No.: 16 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.9 Line No.: 17 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

Schedule Page: 328.9 Line No.: 19 Column: h

OATT rate refund for periods 10/07 thru 12/09

Schedule Page: 328.9 Line No.: 20 Column: h

Imbalance penalty disbtribution per OATT 7.5.1 for periods 07/07 thru 12/09

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	04/15/2011	End of 2010/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	42,089	42,089		230,634		230,634
2	Avista Corp-WWP Div	OS					-2,023	-2,023
3	Avista Corp-WWP Div	OS					-244	-244
4	Avista Corp-WWP Div	SFP	198,623	198,623		1,000,490		1,000,490
5	Bonneville Power Admin	LFP	428,401	428,401	1,195,395			1,195,395
6	Bonneville Power Admin	LFP			53,856			53,856
7	Bonneville Power Admin	NF	3,505	3,505		18,863		18,863
8	Bonneville Power Admin	OS					-3,652	-3,652
9	Bonneville Power Admin	SFP	623	623		2,698		2,698
10	Northwestern Energy	LFP	9,292	9,292	199,600			199,600
11	NorthWesern Energy	NF	4,937	4,937		22,581		22,581
12	NorthWestern Energy	OS					-23,344	-23,344
13	NorthWesern Energy	SFP	139,746	139,746		796,867		796,867
14	PacifiCorp Inc.	LFP	76,431	76,431		759,375		759,375
15	PacifiCorp Inc.	NF	30,440	30,440		164,804		164,804
16	PacifiCorp Inc.	OS					-116	-116
	TOTAL		1,348,861	1,348,861	1,448,851	4,505,995	-36,339	5,918,507

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	PacifiCorp Inc.	OS					-1,920	-1,920
2	PacifiCorp Inc.	SFP	65,389	65,389		708,750		708,750
3	PaTu Wind Farm, Llc	SFP	20,600	20,600		46,552		46,552
4	Portland General Ele Co	SFP	251,609	251,609		582,121		582,121
5	Powerex Corp.	OS					-5,040	-5,040
6	Puget Sound Energy, Inc	SFP	16,394	16,394		21,745		21,745
7	Seattle City Light	SFP	59,020	59,020		145,936		145,936
8	Sierra Pacific Power Co	NF	370	370		2,879		2,879
9	Snohomish County PUD	SFP	1,392	1,392		1,700		1,700
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,348,861	1,348,861	1,448,851	4,505,995	-36,339	5,918,507

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Schedule Page: 332 Line No.: 2 Column: a

Resale Transmission

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

Unreserved Use Refund - Sharing Re-distributed

Schedule Page: 332 Line No.: 5 Column: b

Contract Expiration Date 9/30/2016

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

Contract Expiration Date 7/16/2011

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

Reserves Provided

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

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

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

Resale Transmission

Schedule Page: 332 Line No.: 14 Column: b

Contract Expiration Date 5/31/2014

Schedule Page: 332 Line No.: 16 Column: a

Unreserved Use Refund - Sharing Re-distributed

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

Resale Transmission

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

Resale Transmission

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	371,301
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	173,664
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	[redacted]
6	Richard Dahl	81,166
7	Christine King	66,356
8	Jon Miller	48,700
9	Gary Michael	106,727
10	Richard Reiten	57,091
11	Joan Smith	76,841
12	Jan Packwood	56,116
13	Judith Johansen	74,332
14	Thomas Wilford	66,240
15	Robert Tintsman	72,960
16	Stephen Allred	60,128
17		
18	Chambers of Commerce & Other Civic Organizations	99,881
19		
20	Associated Taxpayers of Idaho	21,252
21	Association of Idaho Cities	3,250
22	Boston College Center for Corporations	2,000
23	Corporate Executive Board	46,750
24	Idaho Assoc of Commerce & Industry	14,000
25	Idaho Association of Counties	1,500
26	National Assoc of Directors	5,500
27	Northwest Power Pool	80,083
28	Pacific NW Utilities	33,810
29	Western Electricity Coordinating Council	857,880
30	Western Energy Institute	46,073
31	Wyoming Taxpayers Assoc	1,590
32	Misc Memberships	1,180
33		
34	Misc General Management	
35	Broadridge Financial Solutions	51,376
36	New York Stock Exchange	47,874
37	PR Newswire	13,685
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,826,102

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

Recipient	Purpose	Amount
Laurel Hill Advisory Group	Mgmt Services	$ 55,781
Stock Based Compensation	Stock Expense	475,200
Thomson Financial	Analyst Service	99,267
Wells Fargo S/O Service	Transfer & Fees	139,384
Deutche Bank	Broker Fees	35,000
Moody's Anaalytics	Analyst Services	27,597
E Source Inc	Mgmt Services	22,480
Rate related Amort	Misc Expense	230,656
other Purchased Service	Misc	101,431
Total		$1,186,796

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			6,857,301		6,857,301
2	Steam Production Plant	18,480,463				18,480,463
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,364,474				15,364,474
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,940,258				4,940,258
7	Transmission Plant	16,395,129				16,395,129
8	Distribution Plant	42,238,509				42,238,509
9	Regional Transmission and Market Operation					
10	General Plant	11,976,663				11,976,663
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	109,099,197		6,857,301		115,956,498

B. Basis for Amortization Charges

Account 404 - Basis used to compute charges:

	Balance to be Amortized 1/1/2010	2010 Amortization	Balance to be Amortized 12/31/2010	Remaining months of Amort 12/31/10
(1)	36,000	12,000	24,000	24
(2)	11,743,090	530,909	12,521,781	-
(3)	18,391,530	6,019,314	17,132,308	-
(4)	5,187,493	287,899	4,899,594	216
(5)	7,179	227,990	-	
Total	35,358,113	6,857,301	34,805,673	

(1) Shoshone-Bannock Tribe License & Use Agreement(Termination date December 31, 2023).
(2) Middle Snake Relicesing Costs (Amortized over a 30 year license period).
(3) Computer Software packages (Amortized over a 60 month period from date of purchase).
(4) Shoshone-Bannock Right of Way (Termination date December 31, 2028).

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	522	75.00		1.05	R4.0	21.80
13	311.00	139,165	100.00	-10.00	1.54	S1.0	23.30
14	312.10	80,615	60.00	-7.00	1.68	R3.0	22.60
15	312.20	464,242	70.00	-5.00	2.17	R1.5	22.30
16	312.30	4,208	25.00	20.00	2.58	R3.0	12.20
17	314.00	148,800	50.00	-5.00	2.55	S0.5	20.30
18	315.00	59,887	65.00	-7.00	5.92	S1.5	22.20
19	316.00	13,876	50.00	-5.00	6.06	R0.5	20.80
20	316.10	59	10.00	25.00	9.52	L2.5	7.60
21	316.40	241	10.00	25.00	9.59	L2.5	
22	316.50	83	10.00	25.00	5.94	L2.5	8.20
23	316.60	106	19.00	25.00	3.69	S2.0	12.00
24	316.70	80	19.00	25.00	3.88	S2.0	16.70
25	316.80	1,042	16.00	30.00	13.90	S0.0	9.30
26	317.000	3,516					
27	Subtotal Steam	916,442					
28	331.00	155,425	100.00	-25.00	2.70	R2.5	32.10
29	332.10	19,461	90.00	-20.00	2.27	S4.0	27.20
30	332.20	225,818	90.00	-20.00	2.22	S4.0	29.80
31	332.30	5,472			2.87	SQUARE	28.60
32	333.00	194,277	80.00	-5.00	1.91	R3.0	33.00
33	334.00	43,762	50.00	-5.00	2.93	R1.5	25.30
34	335.00	17,586	90.00		2.10	R2.0	30.50
35	335.10	25	15.00		1.93	SQUARE	12.30
36	335.20	364	20.00		3.65	SQUARE	10.70
37	335.30	114	5.00		22.92	SQUARE	2.00
38	336.00	7,522	75.00		1.90	R3.0	30.40
39	Subtotal Hydro	669,826					
40	341.00	7,169	35.00		3.02	SQUARE	30.40
41	342.00	4,446	35.00		2.75	SQUARE	32.40
42	343.00	100,802	35.00		2.88	SQUARE	29.70
43	344.00	31,682	35.00		2.85	SQUARE	33.80
44	345.00	25,027	35.00		2.89	SQUARE	28.30
45	346.00	3,119	35.00		2.70	SQUARE	29.50
46	Subtotal Other	172,245					
47	350.20	30,096	65.00		1.51	R3.0	54.20
48	352.00	55,668	60.00	-30.00	1.68	R3.0	47.30
49	353.00	349,451	45.00	-5.00	2.06	R1.0	35.40
50	354.00	144,723	65.00	-25.00	1.96	S3.0	48.60

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	04/15/2011	End of 2010/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	355.00	101,622	55.00	-60.00	2.81	R2.0	36.70
13	356.00	169,166	65.00	-30.00	1.92	R1.5	48.30
14	359.00	318	65.00		0.98	R3.0	23.80
15	Subtotal Transmission	851,044					
16	361.00	29,486	65.00	-30.00	1.85	R2.5	52.60
17	362.00	182,594	50.00	-5.00	1.89	R0.5	42.10
18	364.00	225,060	44.00	-50.00	3.29	R1.5	31.50
19	365.00	120,135	47.00	-40.00	2.95	R0.5	35.10
20	366.00	48,216	60.00	-20.00	1.95	R2.0	51.20
21	367.00	191,494	50.00	-15.00	1.97	S0.5	41.10
22	368.00	414,782	37.00	5.00	1.67	R1.0	30.80
23	369.00	57,320	35.00	-40.00	3.09	R2.5	25.60
24	370.00	14,869	20.00		6.95	O1.0	11.90
25	370.10	39,720	15.00		6.76	S3.0	14.40
26	370.20		2.00		19.38	Square	
27	370.30	41,109	3.00		25.67	Square	1.50
28	371.10	40	10.00	-5.00	3.68	S4.0	1.40
29	371.20	2,711	15.00	-5.00	0.63	R2.0	13.90
30	373.20	4,370	25.00	-25.00	4.09	R1.5	13.90
31	374.00	588					
32	Subtotal Distribution	1,372,494					
33	390.11	26,532	100.00	-5.00	2.38	S1.5	33.60
34	390.12	40,796	50.00	-5.00	2.24	L2.0	36.30
35	390.20	9,950	30.00		2.58	S3.0	20.80
36	391.11	14,505	20.00		4.97	SQUARE	10.30
37	391.20	20,526	5.00		24.37	SQUARE	2.10
38	391.21	4,343	7.00		13.96	L4.0	3.90
39	392.10	708	10.00	25.00	6.23	L2.5	5.90
40	392.30	2,580	8.00	50.00	8.62	S2.5	4.30
41	392.40	19,074	10.00	25.00	3.58	L2.5	7.30
42	392.50	717	10.00	25.00	1.49	L2.5	8.60
43	392.60	29,431	19.00	25.00	3.69	S2.0	12.00
44	392.70	4,419	19.00	25.00	2.39	S2.0	11.90
45	392.90	4,028	30.00	25.00	1.99	S1.5	21.10
46	393.00	1,460	25.00		5.40	SQUARE	9.70
47	394.00	5,568	20.00		4.84	SQUARE	11.70
48	395.00	11,947	20.00		5.39	SQUARE	10.20
49	396.00	9,922	16.00	30.00	6.95	S0.0	7.00
50	397.10	6,158	15.00		6.16	SQUARE	7.70

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	397.20	17,437	15.00		6.99	SQUARE	9.60
13	397.30	3,221	15.00		8.36	SQUARE	6.60
14	397.40	2,399	10.00		8.20	SQUARE	5.60
15	398.00	4,763	15.00		9.57	SQUARE	6.90
16	Subtotal General	240,484					
17	Total Plant	4,222,535					
18							
19							
20							
21							
22							
23							
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REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,454,432		3,454,432	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		-80,742	-80,742	
6					
7	Regulatory Commission Expenses - Idaho				
8	Rate Case - Misc expenses		1,024	1,024	
9					
10	Other- IPUC				
11	Amortization - rate related		5,731	5,731	
12	Other		25,688	25,688	
13					
14	Oregon Hydro - Fees Amortization	158,506		158,506	
15					
16	Regulatory Commission Expenses - Oregon				
17	Rate Case - Misc expenses		6,532	6,532	
18					
19	Other - OPUC				
20	AR - 538		45,710	45,710	
21	UE - 214		73,823	73,823	
22	UM - 1394		33,729	33,729	
23	UM - 1355		20,127	20,127	
24	UM - 1461		19,975	19,975	
25	Other matters less than $15,000		3,301	3,301	
26					
27	Intervenor Funding		30,000	30,000	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	3,612,938	184,898	3,797,836	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	3,454,432					2
							3
							4
Electric	928	-80,742					5
							6
							7
Electric	928	1,024					8
							9
							10
Electric	928	5,731					11
Electric	928	25,688					12
							13
Electric	928	158,506					14
							15
							16
Electric	928	6,532					17
							18
							19
Electric	928	45,710					20
Electric	928	73,823					21
Electric	928	33,729					22
Electric	928	20,127					23
electric	928	19,975					24
Electric	928	3,301					25
							26
Electric	928	30,000					27
							28
							29
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							45
		3,797,836					46

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Approximately $3 million of Idaho Power's 2010	
2	energy efficiency spending was related to	
3	research and analysis, education, technology	
4	evaluation and market transformation. Most of	
5	this activity was done in conjuction with the	
6	Northwest Energy Efficiency Alliance (NEEA).	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	11,875,288		
4	Transmission	4,756,809		
5	Regional Market			
6	Distribution	13,437,082		
7	Customer Accounts	7,300,375		
8	Customer Service and Informational	3,358,835		
9	Sales			
10	Administrative and General	31,661,226		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	72,389,615		
12	Maintenance			
13	Production	5,704,685		
14	Transmission	2,508,585		
15	Regional Market			
16	Distribution	7,125,137		
17	Administrative and General	823,632		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,162,039		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	17,579,973		
21	Transmission (Enter Total of lines 4 and 14)	7,265,394		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	20,562,219		
24	Customer Accounts (Transcribe from line 7)	7,300,375		
25	Customer Service and Informational (Transcribe from line 8)	3,358,835		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	32,484,858		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	88,551,654	26,775,048	115,326,702
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	04/15/2011	End of 2010/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	88,551,654	26,775,048	115,326,702
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	36,304,765	10,583,832	46,888,597
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	36,304,765	10,583,832	46,888,597
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	3,736,188	1,147,087	4,883,275
79	Other Clearing accounts	2,386,875	689,134	3,076,009
80	Other work in progress	1,783,355	494,580	2,277,935
81	Paid Absences	19,473,019		19,473,019
82	Preliminary Survey & Investigation	7,400	2,274	9,674
83	Other Accounts	3,484,843	1,093,622	4,578,465
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	30,871,680	3,426,697	34,298,377
96	TOTAL SALARIES AND WAGES	155,728,099	40,785,577	196,513,676

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	5,031	8	9	3,913	214	904			
2	February	4,865	22	8	3,656	205	904		100	
3	March	4,694	11	8	3,627	152	904		11	
4	Total for Quarter 1	14,590			11,196	571	2,712		111	
5	April	4,540	29	9	3,444	192	904			
6	May	4,623	6	8	3,314	208	904		197	
7	June	5,814	28	19	4,511	304	874		125	
8	Total for Quarter 2	14,977			11,269	704	2,682		322	
9	July	5,755	27	17	4,578	303	874			
10	August	5,740	4	18	4,562	285	874		19	
11	September	5,042	4	18	3,918	250	874			
12	Total for Quarter 3	16,537			13,058	838	2,622		19	
13	October	4,796	1	18	3,532	206	874		184	
14	November	4,905	25	10	3,796	235	874			
15	December	4,899	31	19	3,786	239	874			
16	Total for Quarter 4	14,600			11,114	680	2,622		184	
17	Total Year to Date/Year	60,704			46,637	2,793	10,638		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	04/15/2011	End of 2010/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	6,863,870
4	Nuclear	
5	Hydro-Conventional	7,344,433
6	Hydro-Pumped Storage	
7	Other	159,586
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	14,367,889
10	Purchases	2,377,686
11	Power Exchanges:	
12	Received	438,656
13	Delivered	535,420
14	Net Exchanges (Line 12 minus line 13)	-96,764
15	Transmission For Other (Wheeling)	
16	Received	4,527,461
17	Delivered	4,527,870
18	Net Transmission for Other (Line 16 minus line 17)	-409
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	16,648,402

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,512,504
23	Requirements Sales for Resale (See instruction 4, page 311.)	53,012
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,928,924
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,153,962
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,648,402

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	1,477,843	238,101	2,215	8	8 AM
30	February	1,351,435	288,679	2,049	22	8 AM
31	March	1,313,559	223,940	1,894	11	8 AM
32	April	1,145,768	118,247	1,807	9	8 AM
33	May	1,413,424	281,198	1,906	17	5 PM
34	June	1,458,768	189,213	2,930	28	7 PM
35	July	1,745,903	64,438	2,914	17	7 PM
36	August	1,588,027	66,197	2,874	4	6 PM
37	September	1,328,266	92,700	2,342	3	7 PM
38	October	1,153,195	96,971	2,006	1	6 PM
39	November	1,232,934	95,720	2,149	24	9 AM
40	December	1,439,280	173,520	2,102	30	7 PM
41	TOTAL	16,648,402	1,928,924			

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

Page 329 column I differs from Page 401 by 409 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
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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)	711			60		
7	Plant Hours Connected to Load	8754			7538		
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	4996195000			416874000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	66590599			13810712		
15	Equipment Costs	448784017			57625476		
16	Asset Retirement Costs	0			0		
17	Total Cost	515868974			71542798		
18	Cost per KW of Installed Capacity (line 17/5) Including	669.5250			1114.3738		
19	Production Expenses: Oper, Supv, & Engr	154492			1129338		
20	Fuel	101973965			7273624		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4771475			0		
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	7614528			273881		
27	Rents	303752			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	47818			2144265		
30	Maintenance of Structures	-342			0		
31	Maintenance of Boiler (or reactor) Plant	8061188			0		
32	Maintenance of Electric Plant	2661023			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	3501782			9475		
34	Total Production Expenses	129089681			10830583		
35	Expenses per Net KWh	0.0258			0.0260		
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	2768250	12605	0	248488	593	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9226	140000	0	8347	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	36.494	116.328	0.000	27.585	93.954	0.000
41	Average Cost of Fuel per Unit Burned	36.437	74.795	0.000	28.817	107.042	0.000
42	Average Cost of Fuel Burned per Million BTU	1.961	12.720	0.000	1.739	18.367	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.000	0.017	0.000	0.000
44	Average BTU per KWh Net Generation	10310.000	0.000	0.000	9884.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2001			2005			4
283.50			270.90			172.80			5
262			266			194			6
8653			733			278			7
0			261426			164159			8
0			0			0			9
0			0			0			10
0			8			5			11
1450896000			117685000			41827000			12
1003063			402745			0			13
58763895			5699334			1458303			14
266829313			103750812			60427533			15
0			0			0			16
326596271			109852891			61885836			17
1152.0151			405.5109			358.1356			18
604741			147952			27923			19
37679212			9591014			3140266			20
0			0			0			21
2566086			0			0			22
0			0			0			23
0			0			0			24
2140193			228650			212366			25
1909347			127600			99995			26
-74436			0			0			27
0			0			0			28
100684			0			0			29
309716			96881			74212			30
8006644			69883			9225			31
1254267			744376			279384			32
241757			0			0			33
54738211			11006356			3843371			34
0.0377			0.0935			0.0919			35
Coal			Gas			Gas			36
Tons			MCF			MCF			37
726212	0	0	1178898	0	0	438930	0	0	38
9711	0	0	1027	0	0	1027	0	0	39
50.798	0.000	0.000	8.136	0.000	0.000	7.154	0.000	0.000	40
50.508	0.000	0.000	8.136	0.000	0.000	7.154	0.000	0.000	41
2.600	0.000	0.000	7.922	0.000	0.000	6.966	0.000	0.000	42
0.026	0.000	0.000	0.081	0.000	0.000	0.075	0.000	0.000	43
9759.000	0.000	0.000	10288.000	0.000	0.000	10777.000	0.000	0.000	44

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

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

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

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

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

This footnote applies to lines 3 and 4. The Valmy plant consists of two units constructed jointly by Sierra Pacific Power Company and Idaho Power Company, with Sierra owning 1/2 and Idaho owning 1/2. Unit #1 was placed in commercial operation December 11, 1981 and Unit #2 May 21, 1985.

Schedule Page: 402 Line No.: 5 Column: b

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 402 column B.

Schedule Page: 402 Line No.: 5 Column: c

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note on line 3 page 402 column C

Schedule Page: 402 Line No.: 5 Column: d

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 403 column D.

Schedule Page: 402 Line No.: 9 Column: b

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

Schedule Page: 402 Line No.: 9 Column: c

This footnote applies to lines 9, 10, and 11. Portland General Electric Company, as operator will report this information.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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)	102	55
7	Plant Hours Connect to Load	7,107	8,742
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	5
12	Net Generation, Exclusive of Plant Use - Kwh	318,627,000	336,360,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,358
15	Structures and Improvements	11,807,207	1,039,561
16	Reservoirs, Dams, and Waterways	4,293,075	8,426,020
17	Equipment Costs	31,623,196	7,275,185
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,438,072	17,995,601
21	Cost per KW of Installed Capacity (line 20 / 5)	535.6237	239.9413
22	Production Expenses		
23	Operation Supervision and Engineering	181,953	767,875
24	Water for Power	1,802,201	605,976
25	Hydraulic Expenses	87,770	701,681
26	Electric Expenses	48,195	47,683
27	Misc Hydraulic Power Generation Expenses	199,795	236,503
28	Rents	1,191	24,639
29	Maintenance Supervision and Engineering	132,447	108,083
30	Maintenance of Structures	119,958	63,687
31	Maintenance of Reservoirs, Dams, and Waterways	2,082	194,224
32	Maintenance of Electric Plant	537,112	246,929
33	Maintenance of Misc Hydraulic Plant	111,886	133,441
34	Total Production Expenses (total 23 thru 33)	3,224,590	3,130,721
35	Expenses per net KWh	0.0101	0.0093

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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
654	14	217	6
8,760	8,748	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	7	11
2,247,125,000	35,781,000	975,054,000	12
			13
17,382,696	82,142	1,210,187	14
31,430,623	7,364,154	9,959,405	15
67,073,285	3,145,630	30,375,714	16
55,537,342	12,720,572	15,821,605	17
518,444	122,668	565,842	18
0	0	0	19
171,942,390	23,435,166	57,932,753	20
293.7178	1,886.8894	304.9092	21
			22
560,039	233,028	337,517	23
375,486	176,347	204,837	24
486,157	252,049	273,408	25
282,589	127,312	165,985	26
356,325	163,873	216,071	27
152,023	939	25,667	28
342,659	98,719	242,954	29
117,473	63,250	274,773	30
80,635	12,206	18,127	31
330,984	133,996	135,201	32
547,435	114,511	344,268	33
3,631,805	1,376,230	2,238,808	34
0.0016	0.0385	0.0023	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	04/15/2011	End of 2010/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)	437	24
7	Plant Hours Connect to Load	8,757	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,891,439,000	168,373,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,586,648	2,764,626
16	Reservoirs, Dams, and Waterways	52,700,383	6,199,398
17	Equipment Costs	16,623,664	4,026,866
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	74,607,188	13,500,949
21	Cost per KW of Installed Capacity (line 20 / 5)	190.5675	620.1630
22	Production Expenses		
23	Operation Supervision and Engineering	470,231	99,640
24	Water for Power	291,454	561,246
25	Hydraulic Expenses	445,316	70,876
26	Electric Expenses	222,194	68,526
27	Misc Hydraulic Power Generation Expenses	267,685	66,157
28	Rents	42,439	454
29	Maintenance Supervision and Engineering	350,627	39,054
30	Maintenance of Structures	66,739	9,407
31	Maintenance of Reservoirs, Dams, and Waterways	312,624	87,100
32	Maintenance of Electric Plant	208,451	34,689
33	Maintenance of Misc Hydraulic Plant	568,289	73,785
34	Total Production Expenses (total 23 thru 33)	3,246,049	1,110,934
35	Expenses per net KWh	0.0017	0.0066

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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
86	23	46	6
8,760	8,760	8,744	7
			8
91	24	53	9
84	14	50	10
5	3	5	11
423,822,000	124,623,000	115,370,000	12
			13
5,450,975	51,675	255,499	14
9,143,199	25,478,938	10,808,047	15
10,437,875	13,856,887	7,908,870	16
9,697,355	30,342,755	20,597,667	17
248,183	835,946	1,917,603	18
0	0	0	19
34,977,587	70,566,201	41,487,686	20
422.4346	2,822.6480	786.6455	21
			22
1,027,331	254,735	213,710	23
753,948	180,782	167,496	24
971,545	166,121	132,309	25
50,321	40,466	42,866	26
382,733	116,381	168,313	27
104,526	26,232	7,801	28
204,871	85,180	40,387	29
79,707	66,145	35,430	30
124,754	40,504	4,952	31
639,809	161,351	92,946	32
335,250	220,455	104,233	33
4,674,795	1,358,352	1,010,443	34
0.0110	0.0109	0.0088	35

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	37	14
7	Plant Hours Connect to Load	8,760	8,760
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	231,656,000	91,679,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	1,994,322	1,207,557
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	7,876,561	4,503,350
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,671,812	6,588,020
21	Cost per KW of Installed Capacity (line 20 / 5)	454.2554	527.0416
22	Production Expenses		
23	Operation Supervision and Engineering	377,506	242,269
24	Water for Power	293,497	171,034
25	Hydraulic Expenses	520,922	188,087
26	Electric Expenses	69,795	30,619
27	Misc Hydraulic Power Generation Expenses	192,391	111,877
28	Rents	1,536	1,094
29	Maintenance Supervision and Engineering	137,152	26,133
30	Maintenance of Structures	114,586	11,296
31	Maintenance of Reservoirs, Dams, and Waterways	369,513	10,858
32	Maintenance of Electric Plant	151,797	37,622
33	Maintenance of Misc Hydraulic Plant	157,531	50,272
34	Total Production Expenses (total 23 thru 33)	2,386,226	881,161
35	Expenses per net KWh	0.0103	0.0096

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	43	42	6
0	8,760	8,760	7
			8
0	64	61	9
0	60	1	10
0	7	2	11
0	225,212,000	91,701,000	12
			13
114,367	424,428	138,100	14
26,156,672	2,805,900	10,340,105	15
13,556,785	6,831,204	17,179,601	16
1,190,964	7,907,638	27,676,057	17
99,051	88,693	501,877	18
0	0	0	19
41,117,839	18,057,863	55,835,740	20
0.0000	300.9644	939.2050	21
			22
0	393,812	199,377	23
0	289,420	1,449,135	24
5,871,315	337,020	76,017	25
0	225,890	45,843	26
3,920	201,812	194,523	27
0	9,618	8,272	28
0	73,712	55,974	29
0	71,873	29,103	30
0	25,394	15,643	31
0	229,180	145,523	32
47,490	95,178	61,859	33
5,922,725	1,952,909	2,281,269	34
0.0000	0.0087	0.0249	35

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

American Falls generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

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

Cascade generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

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

Upstream storage in Brownlee Reservoir.

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	2.2	16,021	1,759,925
3	Thousand Springs	1912	8.80	6.5	51,590	5,023,460
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.5	74	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
703,970	62,107		90,873			2
570,848	146,998		196,655			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
						12
						13
						14
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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) 04/15/2011	Year/Period of Report End of 2010/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	226.14		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.08		2
8	Kinport	Borah	345.00	345.00	S Tower	27.10		1
9	Midpoint	Borah #1	345.00	345.00	H Wood	79.29		1
10	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
11	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
12								
13	Quartz	LaGrande	230.00	230.00	H Wood	46.30		1
14	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
15	Brady	Antelope	230.00	230.00	H Wood	56.29		1
16	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
17	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
18	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
19	Brownlee	Ontario	230.00	230.00	S Tower	72.69		1
20	Mora	Bowmont	138.00	230.00	S P Wood	9.90		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	16.10		2
27	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
28	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.10		2
29	Caldwell	Ontario	230.00	230.00	H Wood	27.10		1
30	Caldwell	Ontario	230.00	230.00	S Tower	3.27		1
31	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
32	Borah	Hunt	230.00	230.00	H Steel	68.17		1
33	Danskin	Hubbard	230.00	230.00	H Steel	35.94		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	4,747.29	11.02	182

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
1272 ACSR	256,381	21,776,998	22,033,379					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		802,274	802,274					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,540,614	17,023,923					6
795 ACSR	571,979	11,046,840	11,618,819					7
1272 ACSR	344,220	6,034,618	6,378,838					8
715.5 ACSR	283,143	5,832,249	6,115,392					9
715.5 ACSR	64,851	10,352,361	10,417,212					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	2,841,222	2,903,440					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	2,502,500	2,610,801					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	20,418,606	22,095,444					19
715.5 ACSR	413,793	2,090,601	2,504,394					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	7,070,848	8,819,062					24
715.5 ACSR								25
1272 ACSR	3,062,812	8,029,021	11,091,833					26
795 AAC		80,895	80,895					27
954 ACSR	34,174	16,026,470	16,060,644					28
2X954 ACSR	197,658	5,890,623	6,088,281					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
	30,396,681	415,828,988	446,225,669					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.56		1
2	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
3	Langley Gulch Tap			230.00				
4	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
5	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.23		1
6	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
7	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.69		1
8	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.81		2
9	Oxbow	Brownlee	230.00	230.00	S Tower	10.42		2
10	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
11	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
12	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.04		2
13	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
14	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
15	Brownlee	Boise Bench	230.00	230.00	S Tower	102.12		2
16	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.34		1
17	Palette Jct	Enterprise	230.00	230.00	H Wood	29.12		1
18	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
19	Borah	Brady #2	230.00	230.00	H Wood	3.56		1
20	Borah	Brady #1	230.00	230.00	H Wood	3.88		1
21								
22	Goshen	State Line	161.00	161.00	H Wood	90.48		1
23	Don	Goshen	161.00	161.00	S Tower	2.39		2
24	Don	Goshen	161.00	161.00	H Wood	48.43		2
25								
26	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	10.99		2
27	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
28	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.11		2
29	Nampa	Caldwell	138.00	138.00	S P Wood	10.72		2
30	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.36		1
31	Upper Salmon	Cliff	138.00	138.00	H Wood	30.90		1
32	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
33	Brady	Fremont	138.00	138.00	S Tower	0.98		2
34	Brady	Fremont	138.00	138.00	H Wood	24.32		2
35	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
36					TOTAL	4,747.29	11.02	182

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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	9,197,975	11,052,971					2
	430,883		430,883					3
715.5 ACSR	336,186	4,237,077	4,573,263					4
715.5 ACSR								5
795 ACSR	53,068	2,139,082	2,192,150					6
795 ACSR								7
VARIOUS	289,934	8,047,757	8,337,691					8
1272 ACSR	14,810	1,182,550	1,197,360					9
715.5 ACSR	227,825	6,115,266	6,343,091					10
VARIOUS								11
1272 ACSR	23,308	2,075,244	2,098,552					12
1272 ACSR	138,477	1,386,300	1,524,777					13
1272 ACSR	10,737	1,252,130	1,262,867					14
954 ACSR	184,817	5,624,726	5,809,543					15
715.5 ACSR	247,857	5,423,341	5,671,198					16
1272 ACSR	51,122	1,739,212	1,790,334					17
1272 ACSR	3,068	426,826	429,894					18
715.5 ACSR								19
1272 ACSR	10,064	311,349	321,413					20
								21
250 COPPER	16,155	648,382	664,537					22
715.5 ACSR	76,041	1,652,914	1,728,955					23
397.5 ACSR								24
								25
250 COPPER	26,507	2,396,233	2,422,740					26
250 COPPER								27
715.5 ACSR	21,326	249,233	270,559					28
795 AAC	587,397	1,753,582	2,340,979					29
795 ACSR	47,687	2,635,628	2,683,315					30
795 ACSR	43,568	788,709	832,277					31
795 AAC	270,823	557,504	828,327					32
VARIOUS	564,932	3,719,546	4,284,478					33
VARIOUS								34
VARIOUS								35
	30,396,681	415,828,988	446,225,669					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	04/15/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	King	Lower Malad	138.00	138.00	H Wood	84.73		2
2	Emmett Jct	Payette	138.00	138.00	H Wood	66.45		2
3	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
4	Ontario	Quartz	138.00	138.00	H Wood	73.33		1
5	King	American Falls PP	138.00	138.00	S Tower	1.03		2
6	King	American Falls PP	138.00	138.00	H Wood	148.96		1
7	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
8	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
9	American Falls	Brady Tie	138.00	138.00	H Wood	0.30		1
10	Upper Salmon A-B	King	138.00	138.00	H Wood	6.00		1
11	Upper Salmon B	Wells	138.00	138.00	H Wood	126.40		1
12	King	Wood River	138.00	138.00	H Wood	73.61		1
13	Boise Bench	Grove	138.00	138.00	S P Wood	10.36		2
14	Quartz	John Day	138.00	138.00	H Wood	67.32		1
15	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
16	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
17	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
18	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
19	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
20	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
21	Wood River	Midpoint	138.00	138.00	H Wood	53.05		2
22	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
23	Oxbow	McCall	138.00	138.00	H Wood	37.33		1
24	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
25	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
26	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
27	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.47		1
28	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		2
29	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
30	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.12		2
31	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
32	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
33	Peterson	Tendoy	69.00	138.00	H Wood	57.19		1
34	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.28		1
35	Boise Bench	Mora	138.00	138.00	H Wood	13.15		2
36					TOTAL	4,747.29	11.02	182

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
VARIOUS	76,823	2,068,846	2,145,669					1
VARIOUS	30,918	2,508,477	2,539,395					2
397.5 ACSR	1,955	12,983	14,938					3
VARIOUS	34,428	1,929,353	1,963,781					4
715.5 ACSR	216,919	7,792,986	8,009,905					5
715.5 ACSR								6
715.5 ACSR								7
4\0	4,191	310,154	314,345					8
954 ACSR		96,921	96,921					9
250 COPPER	2,741	93,073	95,814					10
VARIOUS	28,490	2,151,842	2,180,332					11
VARIOUS	173,683	2,670,867	2,844,550					12
VARIOUS	225,602	1,652,772	1,878,374					13
397.5 ACSR	92,173	2,362,416	2,454,589					14
VARIOUS	20	77,199	77,219					15
715.5 ACSR	3,115,486	7,904,710	11,020,196					16
VARIOUS								17
795AAC								18
1272 ACSR								19
250 COPPER	450	154,349	154,799					20
397.5 ACSR	349,567	6,983,609	7,333,176					21
397.5 ACSR								22
397.5 ACSR	109,899	2,306,969	2,416,868					23
397.5 ACSR								24
715.5 ACSR	211,131	1,448,294	1,659,425					25
715.5 ACSR	3,324	1,190,604	1,193,928					26
397.5 ACSR	14,927	587,404	602,331					27
715.5 ACSR	13,734	1,052,549	1,066,283					28
397.5 ACSR	18,223	1,276,855	1,295,078					29
VARIOUS	54,848	2,958,765	3,013,613					30
715.5 ACSR	16,790	206,158	222,948					31
715.5 ACSR	13,616	481,232	494,848					32
397.5 ACSR	395,696	3,449,949	3,845,645					33
715.5 ACSR	343,955	1,058,897	1,402,852					34
715.5 ACSR	14,697	637,273	651,970					35
	30,396,681	415,828,988	446,225,669					36

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
2	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
3	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.94	2.98	1
4	Boise Bench	Butler	138.00	138.00	S P Wood	0.24	4.02	1
5	Eagle	Star	138.00	138.00	S P Wood	6.35		1
6	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.08		1
7	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.21	4.02	1
8	Butler	Wye	138.00	138.00	S P Steel	2.84		1
9	Horseflat	Starkey	138.00	138.00	H Wood	33.86		1
10	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
11	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
12	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
13	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
14	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.79		1
15	Garnet	Ward		138.00				
16	McCall	Lake Fork	138.00	138.00	S P Wood	8.80		1
17	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
18	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
19	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
20	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
21	Valivue Tap		138.00	138.00	S P Steel	0.80		2
22	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
23	Donn	HOKU	138.00	138.00	S P Steel	2.74		1
24	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
25	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
26	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
27	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
28	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.43		1
29	Lower Salmon	King Tie	138.00	138.00	H Wood	0.19		1
30	C J Strike	Strike Jct	138.00	138.00	S Tower	4.39		2
31	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.46		1
32	Strike Jct	Bowmont		138.00	H Wood	0.05		1
33	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
34	Strike Jct	Bowmont	138.00	138.00	H Wood	68.24		1
35	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
36					TOTAL	4,747.29	11.02	182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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.
795 AAC		49,642	49,642					1
795 AAC	489,037	1,944,888	2,433,925					2
1272 ACSR	935,725	3,601,590	4,537,315					3
1272 ACSR	34,687	838,605	873,292					4
715.5 ACSR	179,817	2,909,434	3,089,251					5
795 AAC	43,035	482,937	525,972					6
1272 ACSR	140,412	709,148	849,560					7
795 ACSR	134,471	1,405,436	1,539,907					8
715.5 ACSR	2,472,833	18,211,011	20,683,844					9
715.5 ACSR								10
715.5 ACSR								11
715.5 ACSR								12
715.5 ACSR								13
1272 ACSR	78,579	1,821,921	1,900,500					14
	40,580		40,580					15
715.5 ACSR	331,539	4,682,879	5,014,418					16
								17
1272 ACSR	272,231	2,141,218	2,413,449					18
795 ACSR								19
795 ACSR								20
795 ACSR		351,497	351,497					21
715.5 ACSR	1,174	212,777	213,951					22
1272 ACSR	190	398	588					23
1272 ACSR								24
795 ACSR								25
795 ACSR								26
250 COPPER	58	53,889	53,947					27
715.5 ACSR		76,560	76,560					28
397.5 ACSR		4,406	4,406					29
715.5 ACSR	5,566	385,744	391,310					30
397.5 ACSR	4,355	2,240,408	2,244,763					31
715.5 ACSR	86,651	1,866,338	1,952,989					32
715.5 ACSR								33
								34
715.5 ACSR	7	279,481	279,488					35
	30,396,681	415,828,988	446,225,669					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Bliss	King	138.00	138.00	H Wood	10.60		1
2	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.37		1
3	Swan Falls Tap		138.00	138.00	H Wood	1.02		1
4								
5								
6								
7	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
8								
9								
10	69 Kv Lines		69.00	69.00	H Wood	166.31		1
11	69 Kv Lines		69.00	69.00	S P Wood	929.34		1
12								
13								
14	46 Kv Lines		46.00	46.00	S P Wood	409.26		1
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
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26								
27								
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30								
31								
32								
33								
34								
35								
36					TOTAL	4,747.29	11.02	182

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
715.5 ACSR	5,620	978,001	983,621					1
715.5 ACSR	2,814	183,606	186,420					2
397.5 ACSR	12,885	261,511	274,396					3
								4
								5
								6
397.5 ACSR	1,978	63,404	65,382					7
								8
								9
VARIOUS	1,482,637	46,699,103	48,181,740					10
VARIOUS								11
								12
								13
VARIOUS	308,670	12,379,478	12,688,148					14
								15
								16
								17
								18
								19
								20
								21
								22
								23
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								31
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								33
								34
								35
	30,396,681	415,828,988	446,225,669					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Summer Lake	Hemingway	0.40	S Tower	7.50	1	1
2	Hemingway	Midpoint	0.37	S Tower	8.11	1	1
3							
4	Langley Gulch Tap						2
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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16							
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41							
42							
43							
44	TOTAL		0.77		15.61	2	4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ASCR	TDC-DCTA 15'	500		802,274			802,274	1
1272	ASCR	TDC-DCTA 15'	500						2
									3
			230	430,883				430,883	4
									5
									6
									7
									8
									9
									10
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									12
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									43
				430,883	802,274			1,233,157	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	04/15/2011	End of 2010/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	transmission	230.00	18.00	
10	Bennett Mountain Power Plant	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 (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
300	3					30
		1				31
		1				32
734	5	1				33
30	2					34
20	1					35
6	1	4				36
20	2					37
12	1					38
48	2					39
39	2	1				40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Caldwell	transmission	138.00	69.00	12.47
2	Caldwell	transmission	230.00	138.00	12.47
3	Caldwell	distribution	13.00	4.16	
4	Canyon Creek	distribution	138.00	35.00	
5	Canyon Creek	transmission	138.00	69.00	12.98
6	Cascade Power Plant - attended	transmission	69.00	4.60	
7	Cascade	Distribution	69.00	13.10	
8	Chestnut	distribution	138.00	13.00	
9	Clear Lake - attended	transmission	46.00	2.40	
10	Cliff	transmission	138.00	46.00	12.50
11	Cloverdale	Distribution	138.00	13.00	
12	Dale	distribution	46.00	13.00	
13	Dale	distribution	69.00	13.00	
14	Dale	distribution	138.00	36.20	
15	Dale	Transmission	138.00	46.00	12.47
16	Danskin	Transmission	230.00	18.00	
17	Danskin	transmission	230.00	138.00	13.80
18	Danskin	distribution	18.00	4.16	
19	Danskin	transmission	138.00	12.00	
20	Don	distribution	138.00	7.60	
21	Don	distribution	138.00	13.20	
22	Don	distribution	138.00	13.00	
23	Don	distribution	14.00		
24	DRAM	distribution	138.00	13.09	
25	DRAM	transmission	230.00	138.00	13.80
26	DRAM	distribution	138.00	12.47	
27	Duffin	distribution	138.00	35.00	
28	Eagle	distribution	138.00	13.09	
29	Eastgate	distribution	138.00		
30	Eastgate	distribution	138.00	13.00	
31	Eckert	distribution	138.00	36.20	
32	Eden	distribution	138.00	36.20	
33	Eden	transmission	138.00	46.00	12.98
34	Elkhorn	distribution	138.00	12.47	
35	Elkhorn	distribution	138.00	13.00	
36	Elmore	distribution	138.00	35.00	
37	Elmore	transmission	138.00	69.00	12.50
38	Emmett	distribution	138.00		
39	Emmett	Transmission	138.00	69.00	12.47
40	Falls	distribution	46.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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.
75	3					1
240	2					2
		1				3
15	1					4
15	1					5
12	1					6
10	1					7
48	2					8
4	1					9
16	3	1				10
48	2					11
		7				12
		1				13
27	1					14
25	1					15
140	1					16
180	1					17
6	1					18
96	2					19
		1				20
108	6	3				21
26	1	1				22
80	6					23
118	7					24
160	2					25
17	1					26
36	2					27
38	2					28
24	1					29
18	1	1				30
18	1					31
24	1					32
15	1					33
8	1					34
8	1					35
17	1					36
30	2					37
24	1					38
25	1					39
18	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	04/15/2011	End of 2010/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	Filer	distribution	46.00	13.00	
2	Flying H	distribution	69.00	2.40	
3	Fort Hall	distribution	46.00	13.00	
4	Fossil Gulch	distribution	138.00	35.00	
5	Fremont	transmission	138.00	46.00	12.50
6	Gary	distribution	138.00	13.00	
7	Gem	distribution	69.00	13.00	
8	Gem	distribution	69.00		
9	Goodng Rural	distribution	46.00	13.00	
10	Golden Valley	distribution	69.00	13.00	
11	Gowen Substation	distribution	138.00	35.00	
12	Grindstone	distribution	35.00		
13	Grove	distribution	138.00	13.09	
14	Hagerman	distribution	46.00	13.00	
15	Hagerman	distribution	46.00	13.00	32.00
16	Hailey	distribution	138.00	13.00	
17	Happey Valley	distribution	138.00	13.09	
18	Haven	distribution	138.00	35.00	
19	Haven	transmission	138.00	46.00	
20	Hemingway	transmission	500.00	230.00	34.50
21	Hewlett Packard	distribution	138.00	13.00	
22	Hidden Springs	distribution	138.00	13.00	
23	Highland	distribution	138.00	13.00	
24	Hill	distribution	138.00	13.00	
25	Hillsdale	distribution	138.00		
26	Homedale	distribution	69.00	13.00	
27	Horse Flat	transmission	230.00	138.00	13.80
28	Horse Flat	distribution	69.00	13.00	
29	Horseshoe Bend	distribution	35.00		
30	Horseshoe Bend	distribution	69.00	36.20	
31	Horseshoe Bend	distribution	69.00	25.00	
32	Huston	distribution	69.00	13.00	
33	Hulen	distribution	46.00	13.00	
34	Hunt	transmission	230.00	138.00	13.80
35	Hydra	distribution	138.00	36.20	
36	Island	distribution	69.00	13.00	
37	Jerome	distribution	138.00	13.00	
38	Julion Clawson	distribution	138.00	35.00	
39	Joplin	distribution	138.00	13.00	
40	Joplin	distribution	138.00	35.00	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
15	2					2
10	1	1				3
15	1					4
50	3	1				5
37	2					6
8	1					7
10	1					8
15	2					9
10	1	1				10
24	1					11
5	2					12
72	3					13
10	1					14
5	1					15
20	1					16
18	1					17
12	1					18
25	1					19
600	3	1				20
20	1					21
8	1					22
18	1					23
39	2	1				24
24	1					25
22	2					26
100	1					27
		1				28
5	1					29
12	1					30
5	1					31
10	1					32
10	1					33
300	3					34
48	2					35
12	1					36
40	2					37
30	2					38
15	1					39
18	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	Karcher	distribution	138.00	13.00	
2	Kenyon	distribution	69.00	13.00	
3	Ketchum	distribution	138.00	13.00	
4	Kinport	transmission	161.00	46.00	13.20
5	Kinport	transmission	230.00	138.00	12.47
6	Kinport	transmission	230.00	138.00	13.80
7	Kinport	transmission	345.00	230.00	13.80
8	Kramer	distribution	138.00	35.00	
9	Kramer	distribution	138.00	36.20	
10	Kuna	distribution	138.00	13.00	
11	Lake Fork	distribution	138.00	36.20	
12	Lake Fork	transmission	138.00	69.00	12.50
13	Lamb	distribution	138.00	13.00	
14	Lansing	distribution	69.00	13.00	
15	Lincoln	distribution	138.00	13.09	
16	Linden	distribution	138.00	13.00	
17	Locust	distribution	138.00	36.20	
18	Locust	transmission	230.00	138.00	13.80
19	Lower Malad - attended	transmission	138.00	7.20	
20	Lower Salmon - attended	transmission	138.00	13.80	
21	Map Rock	distribution	69.00	13.00	
22	McCall	distribution	13.00	13.09	
23	McCall	distribution	138.00	36.20	
24	Meridian	distribution	138.00	13.00	
25	Micron	distribution	138.00	13.09	
26	Micron	distribution	138.00	13.00	
27	Midpoint	transmission	230.00	138.00	13.80
28	Midpoint	transmission	345.00	230.00	13.80
29	Midpoint	transmission	500.00	345.00	
30	Midrose	distribution	138.00	13.09	
31	Milner	transmission	138.00	69.00	12.47
32	Milner	distribution	69.00	46.00	6.90
33	Milner	distribution	138.00	35.00	
34	Milner PP - attended	transmission	138.00	13.80	
35	Moonstone	distribution	138.00	35.00	
36	Mora	distribution	138.00	35.00	
37	Mora	distribution	138.00	36.20	
38	Moreland	distribution	35.00	13.00	
39	Moreland	distribution	46.00	13.00	
40	Moreland	distribution	46.00	35.00	12.47

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
20	2					2
42	2					3
		7				4
180	1					5
180	1					6
600	3	1				7
12	1					8
18	1					9
15	1					10
18	1					11
15	1					12
18	1					13
12	1					14
10	1					15
33	2					16
48	2					17
360	2					18
16	1					19
70	4					20
10	1					21
12	1					22
18	1					23
36	2					24
24	2					25
24	2					26
120	1					27
720	2					28
750	3	1				29
24	1					30
100	4					31
8	3	1				32
17	1					33
36	1					34
12	1					35
15	1					36
24	1					37
6	1					38
8	1					39
8	4					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	04/15/2011	End of 2010/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	Mountain Home	distribution	69.00	13.00	
2	Mountain Home Air Force Base	distribution	69.00	13.00	
3	Mountain Home Air Force Base	distribution	138.00	13.00	
4	Nampa	distribution	230.00	138.00	13.80
5	Nampa	distribution	138.00	13.00	
6	New Meadows	distribution	138.00	36.20	
7	New Plymouth	distribution	69.00	13.00	
8	Notch Butte	distribution	13.00	13.09	
9	Orchard	distribution	69.00	36.20	
10	Orchard	distribution	69.00	35.00	12.47
11	Parma	distribution	69.00	13.00	
12	Parma	distribution	69.00	35.00	
13	Paul	distribution	138.00	35.00	
14	Payette	distribution	138.00	13.00	
15	Pingree	transmission	138.00	46.00	12.50
16	Pingree	distribution	138.00	35.00	
17	Pleasant Valley	distribution	138.00	35.00	
18	Pocatello	distribution	46.00	13.00	
19	Poleline	distribution	138.00	13.09	
20	Populus	transmission	345.00		
21	Portneuf	distribution	138.00	35.00	
22	Portneuf	distribution	46.00	35.00	
23	Rockford	distribution	46.00	13.00	
24	Russett	distribution	138.00	13.00	
25	Sailor Creek	distribution	138.00	2.40	
26	Sailor Creek	distribution	138.00	35.00	
27	Salmon	distribution	69.00	13.00	
28	Salmon	distribution	69.00	34.50	12.50
29	Salmon	transmission	13.00	2.40	
30	Shoshone	distribution	46.00	13.00	
31	Shoshone	distribution	46.00	7.20	
32	Shoshone Falls - attended	transmission	46.00	2.30	
33	Shoshone Falls - attended	transmission	46.00	6.60	
34	Silver	distribution	138.00	35.00	
35	Simplot	distribution	138.00	13.00	
36	Sinker Creek	distribution	138.00	35.00	
37	Siphon	distribution	138.00	35.00	
38	South Park	distribution	46.00	13.00	
39	Star	distribution	138.00	13.09	
40	Starkey	Transmission	138.00	69.00	12.50

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
		1				2
18	1					3
180	1					4
50	3					5
12	1					6
10	1					7
10	1					8
6	1					9
10	3					10
10	1					11
12	1					12
36	2					13
23	3					14
50	3					15
22	2					16
42	2					17
18	1					18
18	1					19
						20
18	1					21
		1				22
14	2					23
18	1					24
15	2					25
15	1					26
10	1	4				27
10	3	1				28
5	2					29
10	1					30
2	3					31
3	1					32
10	1					33
12	1					34
15	1					35
12	1					36
33	2					37
10	1					38
18	1					39
18	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2011	End of 2010/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	State	distribution	69.00	13.00	
2	Stoddard	distribution	138.00	13.00	
3	Strike Power Plant - attended	transmission	138.00	13.80	
4	Sugar	distribution	138.00	35.00	
5	Swan Falls - attended	transmission	138.00	6.90	
6	Taber	distribution	46.00	13.00	
7	Ten Mile	distribution	138.00	13.09	
8	Terry	distribution	138.00	13.09	
9	Thousand Springs - attended	transmission	46.00	7.20	
10	Thousand Springs - attended	transmission	7.00	2.40	
11	Toponis	distribution	138.00	33.00	
12	Twin Falls	distribution	138.00	13.09	
13	Twin Falls	transmission	138.00	46.00	12.98
14	Twin Falls PP - attended	transmission	138.00	7.20	
15	Twin Falls PP - attended	transmission	138.00	13.20	
16	Upper Malad - attended	transmission	45.00	7.20	
17	Upper Salmon- attended	transmission	138.00	7.20	
18	Ustick	distribution	138.00	13.00	
19	Vallivue	distribution	138.00	13.09	
20	Victory	distribution	138.00	13.00	
21	Ware	distribution	69.00	13.00	
22	Weiser	distribution	69.00	13.00	
23	Weiser	transmission	138.00	69.00	12.47
24	Wilder	distribution	69.00	13.00	
25	Willis	distribution	138.00	13.09	
26	Wye	distribution	138.00	13.00	
27	Zilog	distribution	138.00	13.09	
28					
29					
30	The above are all State of Idaho				
31					
32	Montana:				
33	Peterson	transmission	230.00	69.00	13.20
34					
35	Nevada:				
36	Valmy - attended	transmission	345.00	17.40	
37	Valmy - attended	transmission	345.00	22.00	
38	Wells	transmission	138.00	69.00	13.00
39					
40	Oregon:				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
33	2					1
15	1					2
83	3					3
20	2					4
18	1					5
5	1					6
24	1					7
42	3					8
8	1					9
3	1					10
18	1					11
44	2					12
33	2					13
9	1					14
72	1					15
8	1					16
36	4					17
44	2					18
18	1					19
24	1	1				20
12	1	1				21
20	2					22
25	1					23
10	1					24
18	1					25
56	3					26
24	1					27
						28
						29
						30
						31
						32
30	3	1				33
						34
						35
315	1					36
300	1	1				37
20	3	1				38
						39
						40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/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	Boardman - attended	transmission	500.00	24.00	
2	Boardman - attended	transmission	230.00	7.20	
3	Boardman - attended	transmission	24.00	7.20	
4	Cairo	distribution	69.00	13.00	
5	Hells Canyon - attended	transmission	230.00	13.80	
6	Hells Canyon	distribution	69.00	0.50	
7	Hines	transmission	138.00	115.00	12.47
8	Malheur Butte	distribution	69.00	34.50	
9	Nyssa	distribution	69.00	13.00	
10	Ontario	distribution	138.00	13.00	
11	Ontario	transmission	138.00	69.00	12.47
12	Ontario	transmission	230.00	138.00	13.80
13	Ontario	transmission	138.00	69.00	12.98
14	Ontario	transmission	138.00	69.00	13.09
15	Ore-Ida	distribution	69.00	13.00	
16	Oxbow - attended	transmission	138.00	69.00	13.00
17	Oxbow - attended	transmission	230.00	13.80	
18	Oxbow - attended	transmission	230.00	138.00	13.80
19	Quartz	transmission	138.00	69.00	12.50
20	Quartz	transmission	230.00	138.00	13.00
21	Vale	distribution	69.00	13.00	
22					
23	Wyoming:				
24	Jim Bridger - attended	transmission	345.00	22.00	
25	Jim Bridger - attended	transmission	345.00	230.00	34.50
26					
27					
28					
29					
30					
31	Transformers-distribution substations under 10,000				
32	KVA 83 unattended.				
33					
34					
35					
36					
37					
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.
685	3					1
55	1					2
55	1					3
12	1					4
500	3					5
1	1					6
40	1					7
8	3	1				8
20	2					9
38	2					10
25	1	1				11
240	2					12
50	2					13
		1				14
15	1					15
10	3	1				16
244	2					17
100	1					18
30	2					19
100	3	1				20
10	1					21
						22
						23
1122	2					24
1084	22					25
						26
						27
						28
						29
						30
						31
338						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.2 Line No.: 20 Column: a

See note 5 Page 109.1.

Schedule Page: 426.4 Line No.: 20 Column: a

See Note 5 on Page 109.1.

Schedule Page: 426.5 Line No.: 36 Column: a

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

Schedule Page: 426.5 Line No.: 37 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.: 1 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.: 2 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.: 3 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.: 24 Column: a

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

Schedule Page: 426.6 Line No.: 25 Column: a

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2011	Year/Period of Report End of 2010/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/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	467,652
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
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34				
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December 31, 2010

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IDAHO PUBLIC
UTILITIES COMMISSION

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

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STATEMENT OF INCOME FOR THE YEAR

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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 978,237,919	$ 993,232,456
3	Operating Expenses			
4	Operation Expenses (401)	15	591,076,570	613,147,331
5	Maintenance Expenses (402)	15	66,618,522	64,769,922
6	Depreciation Expense (403)		101,868,184	96,284,156
7	Amort. & Depl. of Utility Plant (404-405)		5,959,981	6,307,117
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Regulatory Study Costs (407)			
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits/Credits (407.3 & 407.4)		-	-
13	Taxes Other Than Income Taxes (408.1)	2	21,747,745	18,952,082
14	Income Taxes - Federal (409.1)	2	7,279,837	14,745,212
15	- Other (409.1)	2	2,997,295	1,466,739
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	2,215,520	12,847,159
17	Investment Tax Credit Adj. - Net (411.4)	2	(1,423,437)	223,185
18	(Less) Gains from Disp. of Utility Plant (411.6)			
19	Losses from Disp. of Utility Plant (411.7)			
20	(Less) Gains from Disposition of Allowances (411.8)			
21	Losses from Disposition of Allowances (411.9)			
22				
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		798,340,218	828,742,902
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 179,897,701	$ 164,489,555

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 11,743,213
FUTA	113,385
State Unemployment	1,044,675
Payroll Deduction & Loading	(12,901,273)
Total Labor Related	0
Property Taxes	18,331,150
Kilowatt-hour Tax	1,344,580
Licenses	4,053
Regulatory Commission Fees	1,837,184
Irrigation PIC	230,778
Total Taxes Other Than Income Taxes	21,747,745
Federal Income Taxes	7,279,837
State Income Taxes	2,997,295
Deferred Income Taxes	2,215,520
Investment Tax Credit Adjustment - Net	(1,423,437)
Total Taxes Allocated to Idaho	$ 32,816,961

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

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

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	$ 636,667	$ 303,143
2	Customer Accounts Receivable (Account 142)	76,792,157	63,612,796
3	Other Accounts Receivable (Account 143)	9,087,713	6,166,234
4	(Disclose any capital stock subscription received)		
5	Total	$ 86,516,536	$ 70,082,172
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,990,343	1,641,302
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 84,526,193	$ 68,440,870
12			
13			
14	Notes Receivable - Account 141: (at 12-31-10)		
15	Directors, officers, and employees - $ -		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-10)		
19	Directors, officers, and employees - $ -		
20			

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

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

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21						
22	Bal. beginning of year	$ 1,990,343	$	$	$ (349,041)	$ 1,641,302
23	Prov. for uncollectibles					
24	for year					
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 1,990,343	$ -	$ -	$ (349,041)	$ 1,641,302
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

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

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO	$ 18,894,101	$ 37,465,907	$ 41,975,080	$ 14,384,928	
4						
5						
6						
7						
8						
9						
10	Total Account 145	18,894,101	37,465,907	41,975,080	14,384,928	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc.	$ -	$ 124,133,570	$ 124,133,570	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ -	$ 124,133,570	$ 124,133,570	$ -	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

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

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

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

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

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	Cloverdale Substation	$ 2,323	**	$ 122,735	
5	**Approval pending				
6					
7					
8					
9					
10					
11					
12					
13					
14	Total gain	$ 2,323		$ 122,735	
15					
16					
17	CJ Strike	$ 3,834	**		$ (3,155)
18	**Approval pending				
19					
20					
21					
22	Transmission Line #103	*			(200)
23	* Land purchased in 1942. Could not identify				
24	original cost in asset records				
25					
26					
27					
28					
29					
30					
31	Total loss	$ 3,834			$ (3,355)

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ACCENTIENT INC	Computer Support Services	$ 21,000
2	ADECCO ENGINEERING & TECHNICAL	Staffing Services	143,855
3	ADVERTISING CHECKING BUREAU IN	Consulting Services	17,913
4	AERO-GRAPHICS	Mapping Services	53,537
5	ALEKSANDER & ASSOCIATES PA	Consulting Services	24,677
6	ANTHONY & ASSOCIATES, INC.	Consulting Services	11,266
7	ATER, WYNNE LLP	Legal Services	14,283
8	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	349,524
9	BERGLES LAW LLC	Legal Services	61,526
10	BLANK & ASSOCIATES P.S.	Legal Services	11,362
11	BLUE HERON CONSULTING, INC	Consulting Services	87,432
12	BOISE STATE UNIVERSITY	Environmental Services	15,850
13	BRASSEY, WETHRELL, & CRAWFORD,	Legal Services	48,769
14	BRENNEMAN, JOHN	Lobby Serices	73,319
15	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	535,047
16	CADMUS GROUP INC, THE	Consulting Services	208,338
17	CASCADE ENERGY ENGINEERING INC	Engineering Services	101,283
18	CH2M HILL	Engineering Services	20,000
19	CLEAREDGE PARTNERS INC	Computer Support Services	119,250
20	COMSYS INFORMATION TECHNOLOGY	Computer Support Services	123,036
21	CSHQA	Architect Services	26,049
22	DAVIS WRIGHT TREMAINE LLP	Legal Services	414,306
23	DEAN & CARTER PLLC	Legal Services	31,909
24	DELOITTE & TOUCHE LLP	Accounting Sercices	511,015
25	DESERT RESEARCH INSTITUTE	Environmental Services	42,657
26	DEWEY & LEBOEUF LLP	Legal Services	2,711,407
27	DHI INC	Environmental Services	22,274
28	EBERLE, BERLIN, KADING, TURNBO	Legal Services	39,160
29	ECOANALYSTS INC	Environmental Services	22,160
30	ECOS IQ	Consulting Services	93,522
31	ECOTOPE	Architect Services	20,524
32	ENGLAND CONSULTING	Consulting Services	23,100
33	ERISA LAW GROUP PA	Legal Services	20,997
34	ETALK CORPORATION	Consulting Services	16,652
35	EUREKA SOFTWARE	Computer Support Services	46,169
36	EVERGREEN CONSULTING GROUP, LL	Consulting Services	23,340
37	FLUID MARKET STRATEGIES INC	Marketing Services	17,262
38	GARTNER GROUP	Computer Support Services	171,280
39	GIVENS PURSLEY LLP	Legal Services	69,287
40	GJORDING & FOUSER, PLLC	Legal Services	17,120
41	GLAHE & ASSOCIATES INC	Environmental Services	34,697
42	GLOBAL ENERGY PARTNERS LLC	Environmental Services	73,685
43	HARDESTY, REBECCA	Environmental Services	21,891

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
44	HERITAGE ENVIRONMENTAL CONSULT	Environmental Services	$ 59,281
45	HONEYWELL INTERNATIONAL INC	Consulting Services	36,386
46	HYQUAL	Environmental Services	75,317
47	IBM BUSINESS CONTINUITY	Computer Support Services	23,424
48	IDAHO HELICOPTERS INC	Transportation Services	15,553
49	INTER-FLUVE, INC.	Environmental Services	17,811
50	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	96,950
51	JONES AND SWARTZ PLLC	Legal Services	20,316
52	JUB ENGINEERS	Engineering Services	29,489
53	KLARQUIST SPARKMAN LLP	Legal Services	11,771
54	MAINLINE INFORMATION SYSTEMS	Computer Support Services	93,965
55	MCCLURE ENGINEERING	Engineering Services	12,000
56	MCDOWELL RACKNER & GIBSON PC	Legal Services	698,509
57	MERRILL COMM.	Consulting Services	52,000
58	MIRANDE, MICHAEL	Legal Services	51,286
59	NIELSEN GROUP INC, THE	Consulting Services	229,981
60	ORACLE CORPORATION	Computer Support Services	69,176
61	PAINE HAMBLEN LLP	Management Services	316,320
62	PANTER, GREGORY W	Legal Services	18,000
63	PARR BROWN GEE & LOVELESS INC	Legal Services	45,796
64	PLANNEDSCAPE	Consulting Services	34,485
65	PORTLAND ENERGY CONSERVATION	Environmental Services	62,487
66	PROFESSIONAL TRAINING SYSTEMS	Management Services	17,889
67	REYNOLDSON GROUP PLLC	Legal Services	29,075
68	RIDDELL WILLIAMS P.S.	Legal Services	24,979
69	S G S STATISTICAL SERVICES	Consulting Services	14,250
70	SALLADAY & DAVIS	Legal Services	46,094
71	SCIENCE APPLICATIONS INTE	Engineering Services	18,585
72	SCOTT A WELLS, PHD, PE	Engineering Services	14,184
73	SHARP & SMITH INC.	Engineering Services	124,266
74	SHOOK DORAN KOEHL LLP	Legal Services	13,855
75	SOFTWARE AG INC	Computer Support Services	117,000
76	SOS STAFFING SERVICES	Staffing Services	11,703
77	SPATIAL NETWORK SOLUTIONS	Admin Training Services	14,509
78	STAPLEY ENGINEERING, INC	Engineering Services	49,157
79	STEPHAN, KVANVIG, STONE & TRAI	Legal Services	10,270
80	STEPTOE & JOHNSON LLP	Legal Services	485,177
81	STILLWATER SCIENCES	Environmental Services	45,996
82	STOEL RIVES LLP	Legal Services	301,175
83	SULLIVAN & CROMWELL	Manangement Sevices	160,260
84	TETRA TECH INC	Environmental Services	27,115
85	TROUT, JONES, GLEDHILL, FUHRMA	Legal Services	11,630

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
86	UNIVERSITY OF IDAHO	Environmental Services	$ 415,832
87	UTAH STATE UNIVERSITY	Environmental Services	32,500
88	WEATHER MODIFICATION INC	Cloud Seeding Services	343,718
89	XTENSIBLE SOLUTIONS, INC	Consulting Services	89,815
90	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	26,735
	TOTAL		11,027,799

PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	A TREEHOUSE	Computer/Printer Supplies	$ 9,087
2	CGI TECHNOLOGIES AND SOLUTIONS	Computer Support Services	8,251
3	COLLEGE OF IDAHO	Environmental Services	6,500
4	CONNOR CLAIMS SPECIALISTS	Insurance Services	6,269
5	EVANS KEANE	Legal Services	8,987
6	FALTER PHD, C. MICHAEL	Environmental Services	6,400
7	FEHRN, BRIAN	Meterologist Services	7,900
8	FIRE CAUSE ANALYSIS	Consulting Services	7,396
9	GLOBAL ENERGY	Consulting Services	7,951
10	JIM GRAY CONSULTANTS LLC	Consulting Services	7,731
11	LEVIN STRATEGIC RESOURCES LLC	Lobbyist Services	6,000
12	MONTANA STATE UNIVERSITY	Environmental Services	8,600
13	MOORE INFORMATION INC	Consulting Services	9,450
14	MUSGROVE ENGINEERING PA	Engineering Services	7,040
15	NORTHWEST NATURAL RESOURCE GRO	Environmental Services	5,975
16	OFFICE EQUIPTMENT COMPANY	Office Equipment Services	7,715
17	REGULUS INTEGRATED SOLUTIONS L	Consulting Services	6,438
18	RIPLEY, LARRY D	Legal Services	7,725
19	RIVERSIDE TECHNOLOGY INC	Management Services	8,073
20	TREASURE VALLEY LEGAL SERVICES	Legal Services	8,009
21	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	6,000
22	WALDNER LAW OFFICES LLC	Legal Services	5,880
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
	TOTAL		163,377

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ (42,600)	
3	(302) Franchises and Consents	20,610,043	
4	(303) Miscellaneous Intangible Plant	32,188,432	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	52,755,874	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	3,639,403	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	850,081,599	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28			
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	663,043,595	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			$ 5,295	(301)	2
			22,096,463	(302)	3
			30,622,473	(303)	4
			52,724,230		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			3,914,571	(317)	15
			875,741,735		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			667,634,463		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 163,688,832	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,676,814,026	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	26,355,337	
49	(352) Structures and Improvements	36,874,135	
50	(353) Station Equipment	259,189,976	
51	(354) Towers and Fixtures	118,781,110	
52	(355) Poles and Fixtures	78,699,437	
53	(356) Overhead Conductors and Devices	130,470,816	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	259,091	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	650,629,901	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,464,403	
61	(361) Structures and Improvements	25,428,370	
62	(362) Station Equipment	171,224,978	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	198,384,439	
65	(365) Overhead Conductors and Devices	112,606,744	
66	(366) Underground Conduit	47,630,314	
67	(367) Underground Conductors and Devices	183,885,941	
68	(368) Line Transformers	365,533,296	
69	(369) Services	53,584,402	
70	(370) Meters	76,159,662	
71	(371) Installations on Customer Premises	2,428,221	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,035,560	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,245,366,330	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	9,965,131	
78	(390) Structures and Improvements	70,985,209	
79	(391) Office Furniture and Equipment	37,805,449	
80	(392) Transportation Equipment	54,565,482	
81	(393) Stores Equipment	1,232,339	
82	(394) Tools, Shop, and Garage Equipment	4,861,786	
83	(395) Laboratory Equipment	10,696,887	
84	(396) Power Operated Equipment	8,556,954	
85	(397) Communication Equipment	25,366,534	
86	(398) Miscellaneous Equipment	3,912,553	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	227,948,323	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	227,948,323	
91	TOTAL (Accounts 101 and 106)	3,853,514,454	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 3,853,514,454	

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	44
			$ 166,775,956		45
			1,710,152,154		46
					47
			29,203,182	(350)	48
			47,523,329	(352)	49
			300,054,738	(353)	50
			123,384,005	(354)	51
			86,608,519	(355)	52
			144,200,672	(356)	53
				(357)	54
				(358)	55
			271,410	(359)	56
				(359.1)	57
			731,245,855		58
					59
			4,552,220	(360)	60
			28,289,519	(361)	61
			175,260,257	(362)	62
				(363)	63
			208,275,965	(364)	64
			112,894,031	(365)	65
			47,510,380	(366)	66
			188,247,935	(367)	67
			377,055,642	(368)	68
			54,375,115	(369)	69
			92,208,012	(370)	70
			2,517,879	(371)	71
				(372)	72
			4,156,853	(373)	73
				(374)	74
			1,295,343,809		75
					76
			10,327,475	(389)	77
			71,746,675	(390)	78
			36,556,870	(391)	79
			56,593,719	(392)	80
			1,354,873	(393)	81
			5,168,975	(394)	82
			11,091,499	(395)	83
			9,211,910	(396)	84
			27,122,872	(397)	85
			4,421,669	(398)	86
			233,596,537		87
				(399)	88
				(399.1)	89
			233,596,537		90
			4,023,062,586		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 4,023,062,586		96

ELECTRIC OPERATING REVENUES (Account 400)

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

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 385,897,031	$ 396,249,589
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	325,261,915	326,270,298
5	Large (or Industrial)(See Instr. 4) (2)	126,530,113	130,739,702
6	(444) Public Street and Highway Lighting	3,152,822	3,115,326
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	840,841,882 *	856,374,915
11	(447) Sales for Resale - Opportunity....Non-Firm Only	71,503,889	86,951,072
12	TOTAL Sales of Electricity	912,345,771	943,325,987
13	(449) Provision for Rate Refunds	(10,624,673)	(2,333,063)
14	TOTAL Revenue Net of Provision for Refunds	901,721,098	940,992,924
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,455,502	3,738,436
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	18,807,627	16,297,224
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	54,253,693	32,203,871
22			
23			
24			
25	TOTAL Other Operating Revenues	76,516,821	52,239,531
26	TOTAL Electric Operating Revenues	$ 978,237,919	$ 993,232,456

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

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

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

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,777,821,745	5,094,579,185	394,132	391,759	2
				3
5,248,080,006	5,260,695,289	76,563	76,494	4
2,828,443,711	2,889,807,183	118	120	5
29,217,485	30,137,604	1,438	1,353	6
				7
				8
				9
12,883,562,947 **	13,275,219,261	472,251	469,726	10
1,883,300,132	2,689,972,558	N/A	N/A	11
14,766,863,079	15,965,191,819	472,251	469,726	12
				13

* Includes ($3,167,019) unbilled revenues.

** Includes (25,129,713) KWH relating to unbilled revenues.

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,801,415	$ 1,730,026
5	(501) Fuel	139,614,702	123,530,408
6	(502) Steam Expenses	6,972,393	7,051,991
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	2,033,682	2,436,169
10	(506) Miscellaneous Steam Power Expenses	9,345,596	7,732,363
11	(507) Rents	218,733	490,668
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	159,986,521	142,971,625
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,186,957	1,975,511
16	(511) Maintenance of Structures	295,097	464,737
17	(512) Maintenance of Boiler Plant	15,268,185	12,971,894
18	(513) Maintenance of Electric Plant	3,720,438	3,410,225
19	(514) Miscellaneous Steam Plant	3,579,816	4,422,214
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,050,493	23,244,580
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	185,037,013	166,216,205
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,113,329	4,996,334
45	(536) Water for Power	6,984,811	6,839,199
46	(537) Hydraulic Expenses	10,179,310	9,622,038
47	(538) Electric Expenses	1,492,017	1,400,051
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,762,087	2,561,153
49	(540) Rents	387,675	359,232
50	TOTAL Operation (Enter Total of lines 44 thru 49)	26,919,229	25,778,007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 1,877,060	$ 1,975,236
54	(542) Maintenance of Structures	1,102,320	1,331,517
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,305,050	1,079,628
56	(544) Maintenance of Electric Plant	3,026,857	2,819,107
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,889,665	2,832,668
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,200,952	10,038,157
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	37,120,181	35,816,164
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	313,261	331,668
63	(547) Fuel	12,111,625	18,336,546
64	(548) Generation Expenses	427,597	385,488
65	(549) Miscellaneous Other Power Generation Expenses	429,404	305,054
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	13,281,887	19,358,755
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	41	0
70	(552) Maintenance of Structures	173,642	185,036
71	(553) Maintenance of Generating and Electric Plant	112,955	497,807
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,027,549	1,630,541
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,314,187	2,313,384
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	14,596,074	21,672,139
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	131,000,128	152,316,715
77	(556) System Control and Load Dispatching	153	12,528
78	(557) Other Expenses	51,884,430	73,149,445
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	182,884,710	225,478,687
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	419,637,978	449,183,196
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,559,146	2,146,091
84	(561) Load Dispatching	2,816,811	2,232,972
85	(562) Station Expenses	1,706,312	1,658,377
86	(563) Overhead Line Expenses	562,633	763,563
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	5,623,961	6,287,468
89	(566) Miscellaneous Transmission Expenses	288,013	327,409
90	(567) Rents	1,341,727	1,324,828
91	TOTAL Operation (Enter Total of lines 83 thru 90)	14,898,602	14,740,708
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	462,021	499,815
94	(569) Maintenance of Structures	357,888	327,684
95	(570) Maintenance of Station Equipment	2,960,318	2,556,220
96	(571) Maintenance of Overhead Lines	2,370,823	2,471,315
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	(34)	32
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	6,151,015	5,855,065
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	21,049,617	20,595,774
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,494,071	3,141,623

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 3,280,881	$ 3,014,735
106	(582) Station Expenses	1,226,496	1,072,819
107	(583) Overhead Line Expenses	2,818,499	3,169,511
108	(584) Underground Line Expenses	1,762,795	1,885,378
109	(585) Street Lighting and Signal System Expenses	75,649	128,093
110	(586) Meter Expenses	4,065,420	4,309,928
111	(587) Customer Installations Expenses	1,392,551	1,217,628
112	(588) Miscellaneous Distribution Expenses	4,708,623	4,682,137
113	(589) Rents	414,753	288,975
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,239,738	22,910,827
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	350,009	290,469
117	(591) Maintenance of Structures	(10,923)	23,673
118	(592) Maintenance of Station Equipment	3,623,115	3,166,911
119	(593) Maintenance of Overhead Lines	13,302,525	13,336,846
120	(594) Maintenance of Underground Lines	986,863	1,066,017
121	(595) Maintenance of Line Transformers	407,395	373,749
122	(596) Maintenance of Street Lighting and Signal Systems	559,210	476,614
123	(597) Maintenance of Meters	674,552	685,447
124	(598) Maintenance of Miscellaneous Distribution Plant	125,929	244,352
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	20,018,674	19,664,077
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	43,258,412	42,574,904
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	392,236	357,284
130	(902) Meter Reading Expenses	3,753,549	5,092,915
131	(903) Customer Records and Collection Expenses	12,502,606	12,604,114
132	(904) Uncollectible Accounts	4,479,964	5,092,669
133	(905) Miscellaneous Customer Accounts Expenses	327	533
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	21,128,682	23,147,516
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	339,665	257,106
138	(908) Customer Assistance Expenses	50,028,521	40,542,279
139	(909) Informational and Instructional Expenses	30,338	15,511
140	(910) Miscellaneous Customer Service and Informational Expenses	831,888	836,024
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	51,230,413	41,650,920
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	60,008,898	57,849,175
152	(921) Office Supplies and Expenses	12,833,065	11,682,289
153	(Less) (922) Administrative Expenses Transferred-Credit	(26,204,991)	(26,136,870)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 6,797,014	$ 7,093,497
156	(924) Property Insurance	3,112,351	3,046,423
157	(925) Injuries and Damages	5,343,230	6,381,755
158	(926) Employee Pensions and Benefits	28,308,455	29,122,006
159	(927) Franchise Requirements	2,549	3,196
160	(928) Regulatory Commission Expenses	3,293,914	4,579,316
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	393,976	148,379
163	(930.2) Miscellaneous General Expenses	3,606,629	3,340,110
164	(931) Rents	11,698	1,009
165	TOTAL Operation (Enter Total of lines 151 thru 164)	97,506,787	97,110,285
166	Maintenance		
167	(935) Maintenance of General Plant	3,883,202	3,654,659
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	101,389,989	100,764,944
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 657,695,092	$ 677,917,253

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

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

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

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

1	Payroll Period Ended (Date)	December 31, 2010	December 31, 2009
2	Total Regular Full-Time Employees	1,928	1,979
3	Total Part-Time and Temporary Employees	50	24
4	Total Employees	1,978	2,003