e-FILING REPORT COVER SHEET

REPORT NAME: 2014 FERC Form 1 Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

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

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

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

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

If Yes, enter docket number:

Key words:

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

- ☐ Corporate Analysis and Water Regulation
- ☐ Economic and Policy Analysis
- ☐ Electric and Natural Gas Revenue Requirements
- ☐ Electric Rates and Planning
- ☐ Natural Gas Rates and Planning
- ☐ Utility Safety, Reliability & Security
- ☐ Administrative Hearings Division
- ☐ Consumer Services Section

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

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

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 28, 2015

Public Utility Commission of Oregon
Filing Center
3930 Fairview Industrial Drive SE
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Idaho Power Company's 2014 Annual FERC Form 1 Report

Attention Filing Center:

As required by OAR 860-027-0070, Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report and Oregon supplement for the year ending December 31, 2014. Also included is the IDACORP 2014 Annual Report.

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

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2014/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
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7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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	04/15/2015	End of 2014/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	04/15/2015	End of 2014/Q4

GENERAL INFORMATION

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

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

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

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

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [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	04/15/2015	End of 2014/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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 & Chief Executive Officer	Darrel T. Anderson	575,000
3			
4	Executive Vice President & Chief Operating Officer	Dan Minor	430,000
5			
6	Senior Vice President & General Counsel	Rex Blackburn	335,000
7			
8	Senior Vice President, Power Supply	Lisa Grow	300,000
9			
10	Senior Vice President, CFO & Treasurer	Steven Keen	315,000
11			
12	Vice President, Human Resources & Corporate Services	Luci McDonald	265,000
13			
14	Vice President, Customer Operations	Warren Kline	260,000
15			
16	Vice President, Public Affairs	Jeffrey Malmen	245,000
17			
18	Vice President, & Chief Risk Officer	Lori Smith	233,000
19			
20	Vice President Delivery, Engineering & Construction	Vern Porter	235,000
21			
22	Vice President,Controller & Chief Accounting Officer	Ken Petersen	215,000
23			
24	Vice President & Chief Information Officer	Lonnie Krawl	208,000
25			
26	Vice President, Regulatory Affairs	Gregory Said	210,000
27			
28	Corporate Secretary	Patrick Harrington	182,000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A. Johansen	1809 Headlee Lane, Lake Oswego, Oregon 97034
3		
4	Christine King***	8527 East old Field Rd
5		Scottsdale, Azizona 85266
6		
7	Stephen Allred (1)	4642 W Dawson Dr., Meridian, Idaho 83646
8		
9	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
10		
11	Darrel T. Anderson President & Chief Executive Office	Idaho Power Company, 1221 W. Idaho Street,
12		P.O. Box 70, Boise, Idaho 83707-0070
13		
14	J. LaMont Keen, ** ***	481 North Strata Via Way, Boise Idaho 83712
15		
16		
17	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
18		
19	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
20		
21	Thomas Wilford	1504 Warm Springs Avenue
22		Boise, Idaho 83712
23		
24	Richard Dahl ***	60 Laiki Pl.
25		Kailua, Hawaill 96734
26		
27	Dennis L. Johnson	United Heritage Life Insurance
28		707 E. United Heritage Ct., Ste 130, Meridian, Idaho 83642
29		
30	Ronald W. Jibson	Questar Corporation
31		333 South State Street, Salt Lake City, Utah 84145-0433
32		
33	Thomas Carlile (2)	2719 North Woodview place, Boise Idaho 83702
34		
35		
36		
37	(1) Retired on May 15, 2014	
38	(2) Appointed to Board March 19, 2014	
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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	04/15/2015	End of 2014/Q4

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

Does the respondent have formula rates?	[X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	201408285251	08/28/2014	ER09-1641-000	Idaho Power Company	FERC Electric Tariff
2				2014 Annual	
3				informational filing	
4				under ER-09-1641-000	
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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) 04/15/2015	Year/Period of Report End of 2014/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	None			
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. Line #134 Line was rerouted into Bowmont substation. A portion was removed from underbuild on line 248 and given its own alignment farther South.
Line #248 Removed de-energized line around Chestnut substation.
Line #464 Added .36 miles to reroute around the new hwy 16/44 intersection.
Line #479 A new 138kv line was placed in service between Bowmont and Happy Valley substations. 8.64 miles

   There continues to be realignment using LiDar data and Aerial photos. This realignment will result in small additions or deletions to line lenghts. There were several other lines where data errors or omissions have also been corrected.

6. As of December 31,2014 Idaho Power had not sold any first mortgage bonds, including Series J notes, or debt securities under the selling agency agreement.

7. None

8. Effective 1/04/2014 a 3.0 general wage adjustment was implemented.

9. See pages 123.19 to 123.20

10. None

11. None

12. None

13. Idaho Power has added Thomas Carlile as a director effective 3/19/2014. Stephen Allred retired effective 5/15/2014.

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 advance from Idaho Power to IDACORP through a cash management program.

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,255,302,762	5,087,492,230
3	Construction Work in Progress (107)	200-201	401,929,509	327,000,038
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,657,232,271	5,414,492,268
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,021,073,827	1,940,654,182
6	Net Utility Plant (Enter Total of line 4 less 5)		3,636,158,444	3,473,838,086
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,636,158,444	3,473,838,086
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,555,480	1,274,121
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	83,477,460	91,384,573
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)		647	824
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		45,082,335	42,271,755
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		63,323	288,132
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		130,179,245	135,219,405
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		46,581,578	66,420,846
36	Special Deposits (132-134)		1,079,260	3,106,514
37	Working Fund (135)		13,600	14,100
38	Temporary Cash Investments (136)		100,000	100,000
39	Notes Receivable (141)		0	50,208
40	Customer Accounts Receivable (142)		85,040,915	100,221,798
41	Other Accounts Receivable (143)		14,677,441	11,336,452
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,650,829	2,501,686
43	Notes Receivable from Associated Companies (145)		2,053,197	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	55,170,482	41,546,323
46	Fuel Stock Expenses Undistributed (152)	227	599	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	50,305,479	49,267,705
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

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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	5,098,760	4,375,589
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)		18,355,589	15,204,045
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		56,269,642	63,506,686
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		634,183	1,672,362
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		63,323	288,132
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)		330,666,573	354,032,810
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,815,910	17,183,115
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,237,823,724	1,036,375,119
73	Prelim. Survey and Investigation Charges (Electric) (183)		873,939	883,871
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		1,053,324	2,147,654
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	45,564,713	45,208,766
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)		12,799,888	13,860,473
82	Accumulated Deferred Income Taxes (190)	234	289,103,584	246,774,821
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,603,035,082	1,362,433,819
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,700,039,344	5,325,524,120

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	end of 2014/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		712,257,435	712,257,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	952,335,875	843,625,028
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	81,014,366	88,921,479
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)	-24,157,999	-16,553,375
16	Total Proprietary Capital (lines 2 through 15)		1,817,229,782	1,724,030,672
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,595,460,000	1,595,460,000
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	23,075,909	24,139,545
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,034,022	3,277,591
24	Total Long-Term Debt (lines 18 through 23)		1,615,501,887	1,616,321,954
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)		1,994,972	1,670,695
29	Accumulated Provision for Pensions and Benefits (228.3)		403,474,921	245,780,272
30	Accumulated Miscellaneous Operating Provisions (228.4)		3,865,254	2,771,356
31	Accumulated Provision for Rate Refunds (229)		72,974,757	59,388,816
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)		21,930,049	25,765,364
35	Total Other Noncurrent Liabilities (lines 26 through 34)		504,239,953	335,376,503
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		113,979,552	105,671,106
39	Notes Payable to Associated Companies (233)		0	13,264,181
40	Accounts Payable to Associated Companies (234)		2,027,220	1,158,063
41	Customer Deposits (235)		1,568,822	1,428,221
42	Taxes Accrued (236)	262-263	-10,635,253	15,104,410
43	Interest Accrued (237)		22,670,165	22,834,804
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	end of 2014/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,599,099	1,444,649
48	Miscellaneous Current and Accrued Liabilities (242)		40,889,480	35,788,243
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		3,960,704	571,747
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)		177,059,789	197,265,424
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		3,303,553	9,465,217
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,162,831	79,121,290
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	11,635,642	12,386,721
60	Other Regulatory Liabilities (254)	278	64,843,269	70,377,000
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,248,630,361	1,143,090,466
64	Accum. Deferred Income Taxes-Other (283)		178,432,277	138,088,873
65	Total Deferred Credits (lines 56 through 64)		1,586,007,933	1,452,529,567
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,700,039,344	5,325,524,120

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	1,277,640,977	1,242,150,868		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	780,281,536	710,931,086		
5	Maintenance Expenses (402)	320-323	68,283,304	67,728,722		
6	Depreciation Expense (403)	336-337	125,245,540	121,486,191		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	495,029	587,012		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,172,382	7,611,634		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		73,650	56,176		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	31,748,230	30,560,823		
15	Income Taxes - Federal (409.1)	262-263	-7,413,733	9,918,700		
16	- Other (409.1)	262-263	6,908,583	5,499,764		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	152,963,217	138,292,290		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	134,837,097	82,501,409		
19	Investment Tax Credit Adj. - Net (411.4)	266	41,541	-775,313		
20	(Less) Gains from Disp. of Utility Plant (411.6)			6,043		
21	Losses from Disp. of Utility Plant (411.7)			6,766		
22	(Less) Gains from Disposition of Allowances (411.8)		186,382	41,307		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		309,716	322,348		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,031,085,516	1,009,677,440		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		246,555,461	232,473,428		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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
1,277,640,977	1,242,150,868					2
						3
780,281,536	710,931,086					4
68,283,304	67,728,722					5
125,245,540	121,486,191					6
495,029	587,012					7
7,172,382	7,611,634					8
						9
						10
						11
73,650	56,176					12
						13
31,748,230	30,560,823					14
-7,413,733	9,918,700					15
6,908,583	5,499,764					16
152,963,217	138,292,290					17
134,837,097	82,501,409					18
41,541	-775,313					19
	6,043					20
	6,766					21
186,382	41,307					22
						23
309,716	322,348					24
1,031,085,516	1,009,677,440					25
246,555,461	232,473,428					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	04/15/2015	End of 2014/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)		246,555,461	232,473,428		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,009,910	946,897		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,136,669	1,079,771		
33	Revenues From Nonutility Operations (417)		37,547	41,993		
34	(Less) Expenses of Nonutility Operations (417.1)		22,828	60,482		
35	Nonoperating Rental Income (418)		-527	-2,844		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,092,887	6,704,329		
37	Interest and Dividend Income (419)		2,704,620	2,426,000		
38	Allowance for Other Funds Used During Construction (419.1)		17,930,898	14,857,580		
39	Miscellaneous Nonoperating Income (421)		2,453,947	14,488,869		
40	Gain on Disposition of Property (421.1)		-4,240	-2,442		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,065,545	38,320,129		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,156	1,917		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		747,094	744,976		
46	Life Insurance (426.2)		-1,164,064	-18,319		
47	Penalties (426.3)		27,106	428,042		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,561,921	1,282,131		
49	Other Deductions (426.5)		8,332,431	8,655,953		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,506,644	11,094,700		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	24,797	22,991		
53	Income Taxes-Federal (409.2)	262-263	-914,126	1,540,870		
54	Income Taxes-Other (409.2)	262-263	-41,215	417,095		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,085,673	2,496,132		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,008,392	2,173,220		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,853,263	2,303,868		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		22,412,164	24,921,561		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		80,561,920	81,492,149		
63	Amort. of Debt Disc. and Expense (428)		1,610,773	1,609,364		
64	Amortization of Loss on Reaquired Debt (428.1)		1,060,585	1,060,585		
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)		10,524	7,955		
68	Other Interest Expense (431)		4,800,939	4,146,983		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,464,109	7,663,190		
70	Net Interest Charges (Total of lines 62 thru 69)		79,580,632	80,653,846		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		189,386,993	176,741,143		
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)		189,386,993	176,741,143		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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		836,965,502	749,111,203
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)		182,294,106	170,036,814
17	Appropriations of Retained Earnings (Acct. 436)			
18		215.1	-6,613,580	(3,256,123)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-6,613,580	(3,256,123)
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			-88,583,259	(78,926,392)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-88,583,259	(78,926,392)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216	15,000,000	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		939,062,769	836,965,502
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		13,273,106	6,659,526
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		13,273,106	6,659,526
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		952,335,875	843,625,028
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		88,921,479	82,217,150
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,092,887	6,704,329
51	(Less) Dividends Received (Debit)		15,000,000	
52				
53	Balance-End of Year (Total lines 49 thru 52)		81,014,366	88,921,479

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)	189,386,993	176,741,143
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	125,245,540	121,486,191
5	Amortization of Note 1	11,250,901	11,648,544
6			
7			
8	Deferred Income Taxes (Net)	17,218,276	55,836,153
9	Investment Tax Credit Adjustment (Net)	26,665	-497,674
10	Net (Increase) Decrease in Receivables	22,570,540	-30,953,272
11	Net (Increase) Decrease in Inventory	-15,385,702	-1,213,152
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,687,818	7,503,331
14	Net (Increase) Decrease in Other Regulatory Assets	16,794,041	-40,694,556
15	Net Increase (Decrease) in Other Regulatory Liabilities	15,341,861	15,112,871
16	(Less) Allowance for Other Funds Used During Construction	17,930,898	14,857,580
17	(Less) Undistributed Earnings from Subsidiary Companies	-7,907,113	6,704,329
18	Other (provide details in footnote): Note 2	4,789,855	-17,772,390
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	358,527,367	275,635,280
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-291,841,495	-250,164,015
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	-17,930,898	-14,857,580
31	Other (provide details in footnote): Note 3	3,551,443	498,473
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-270,359,154	-234,807,962
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-15,317,379	14,272,430
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)	-8,000,000	-32,660,820
45	Proceeds from Sales of Investment Securities (a)		25,660,820

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	50,208	22,284
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote): Note 4	4,906,085	3,450,425
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-288,720,240	-224,062,823
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		150,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)		150,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,063,636	-71,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		-2,298,726
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-88,583,259	-78,926,392
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-89,646,895	-2,288,754
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-19,839,768	49,283,703
87			
88	Cash and Cash Equivalents at Beginning of Period	66,534,946	17,251,243
89			
90	Cash and Cash Equivalents at End of period	46,695,178	66,534,946

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

Plant	7,172,382
Unamortized debt expense	2,728,016
Unamortized discount	243,569
Water rights	1,042,009
Other	64,925
	11,250,901

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

Cash paid during the period for:	
Income taxes	22,202,480
Interest (net of amount capitalized)	77,063,389

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

Cash Flow from Operating Activities (Other)	
Pension and postretirement benefit plan expense	44,578,826
Contributions to pension and postretirement benefit plans	(33,672,415)
Unbilled revenues	7,237,044
Prepayments	(4,988,374)
Company owned life insurance	(1,856,230)
Customer deposits	(5,746,063)
Other	(762,933)
	4,789,855

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	28,438,385

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

Other Cash Flows from Plant	
Sale of utility property	620,205
Sale of emission allowances and renewable energy certificates	2,931,238
	3,551,443

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

Other Investing Cash Flows

Disbursements from rabbi trust & EDC plan	**4,905,908**
Miscellaneous other investing activities	**177**

	4,906,085

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

Basis of Reporting

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

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

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

Idaho Power’s financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating

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

Cash and Cash Equivalents

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

Receivables and Allowance for Uncollectible Accounts

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

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

There were no impaired receivables without related allowances at December 31, 2014 and 2013. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

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

Revenues

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

Property, Plant and Equipment and Depreciation

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.68 percent in 2014 and 2.69 percent in 2013.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as construction work in progress on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, Idaho Power may seek recovery of such costs in customer rates, although there can be no guarantee such recovery would be granted.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment is recognized in the financial statements. There were no material impairments of these assets in 2014 or 2013.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the HCC relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power's weighted-average monthly AFUDC rate was 7.7 percent for 2014 and 2013.

Income Taxes

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

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

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

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

Income taxes are discussed in more detail in Note 2.

Other Accounting Policies

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

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. As such, at Idaho Power's required adoption date of January 1, 2017, amounts in 2015 and 2016 may have to be revised. Idaho Power is currently evaluating the impact of ASU 2014-09 on its financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2014 up to February 19, 2015, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2015. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. INCOME TAXES

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows (in thousands of dollars):

	2014	2013
Federal income tax expense at 35% statutory rate	$ 71,810	$ 87,310
Change in taxes resulting from:		
Equity Earnings of subsidiary companies	(2,483)	(2,347)
AFUDC	(9,238)	(7,882)
Capitalized interest	2,278	1,832
Investment tax credits	(3,002)	(3,120)
Removal costs	(3,656)	(3,527)
Capitalized overhead costs	(8,750)	(8,750)
Capitalized repair costs	(26,250)	(19,250)
Tax method change – capitalized repairs	(24,516)	4,583
State income taxes, net of federal benefit	5,334	6,970
Depreciation	16,040	14,820
Other, net	(1,783)	2,076
Total income tax expense	$ 15,784	$ 72,715
Effective tax rate	7.7 %	29.1 %

The items comprising income tax expense are as follows (in thousands of dollars):

	2014	2013
Income taxes current:		
Federal	$ (8,328)	$ 11,460
State	6,867	5,917
Total	(1,461)	17,377
Income taxes deferred:		
Federal	23,624	56,918
State	(6,421)	(804)
Total	17,203	56,114
Investment tax credits:		
Deferred	3,044	2,344
Restored	(3,002)	(3,120)
Total	42	(776)
Total income tax expense	$ 15,784	$ 72,715

The components of the net deferred tax liability are as follows (in thousands of dollars):

	2014	2013
Deferred tax assets:		
Regulatory liabilities	$ 55,490	$ 55,017
Deferred compensation	25,240	23,647
Deferred revenue	28,529	23,062
Tax credits	26,768	23,642
Net operating losses	—	29,628
Retirement benefits	132,571	69,033
Other	14,553	10,359
Total	283,151	234,388
Deferred tax liabilities:		
Property, plant and equipment	451,118	436,837
Regulatory assets	802,188	710,482
Power cost adjustments	23,192	35,763
Retirement benefits	122,360	65,810
Other	22,252	19,901
Total	1,421,110	1,268,793
Net deferred tax liabilities	$ 1,137,959	$ 1,034,405

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

Uncertain Tax Positions

Idaho Power believes that it has no material income tax uncertainties for 2014 and prior tax years. The company recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

Idaho Power is subject to examination by its major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2014 for federal and 2011-2014 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2014, the IRS completed its examination of IDACORP's 2013 tax year with no unresolved income tax issues.

Tax Accounting Method Changes for Repair-Related Expenditures

In the fourth quarter of 2014, Idaho Power finalized an income tax accounting method change for its 2014 tax year associated with the electric generation property portion of its capitalized repairs tax method it adopted in fiscal year 2010. As a result of the change, Idaho Power recorded an $8.8 million tax benefit related to the cumulative method change adjustment for years prior to 2014 and reversed a related $4.6 million tax expense estimate it had recorded in 2013 (discussed below), for a total adjustment of $13.4 million.

The method change is pursuant to Revenue Procedure 2013-24 and will bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric generation property. The change also incorporates provisions of the final tangible property regulations issued by the U.S. Treasury Department (Treasury) and IRS in the third quarter of 2013 that address the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power expects to adopt this method with the filing of IDACORP’s 2014 consolidated federal income tax return in September 2015. The method change will be subject to IRS review as part of IDACORP’s CAP examination.

In the third quarter of 2014, Idaho Power, in coordination with the IRS through IDACORP’s CAP examination process, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in the third quarter. Idaho Power finalized these changes with the filing of IDACORP’s 2013 consolidated federal income tax return in September 2014. The IRS approved the repairs method modifications prior to the filing of the return as part of IDACORP’s 2013 CAP examination.

In connection with the issuance of the tangible property regulations and following the provisions of Revenue Procedure 2013-24 (discussed above), in the third quarter of 2013 Idaho Power assessed and estimated the impact of a method change associated with the electric generation property portion of its capitalized repairs method. Based upon this assessment, in 2013 Idaho Power recorded $4.6 million of income tax expense related to the estimated cumulative method change adjustment for years prior to 2013.

The amount of the capitalized repairs annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power’s annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power’s prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type, commonly referred to as “flow-through.” A net regulatory asset is established to reflect Idaho Power’s ability to recover the net increased income tax expense when such temporary differences reverse. Idaho Power’s 2014 capitalized repairs deduction estimate incorporates the provisions of both method changes.

3. REGULATORY MATTERS

Included below is information on Idaho Power's regulatory assets and liabilities, as well as a summary of Idaho Power's most recent general rate changes and other notable recent or pending regulatory matters and proceedings.

Regulatory Assets and Liabilities

The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would record such expenses and revenues. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense. The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

	Remaining Amortization Period	As of December 31, 2014 Earning a Return(1)	As of December 31, 2014 Not Earning a Return	Total as of December 31, 2014	Total as of December 31, 2013
Regulatory Assets:					
Income taxes		$ —	$ 802,188	$ 802,188	$ 710,482
Unfunded postretirement benefits(2)		—	264,548	264,548	116,583
Pension expense deferrals		40,816	22,828	63,644	75,108
Energy efficiency program costs(3)		4,690	—	4,690	3,694
Power supply costs(3)	Varies	59,189	—	59,189	91,477
Fixed cost adjustment(3)	2015-2016	23,737	—	23,737	19,526
Asset retirement obligations(4)		—	17,309	17,309	18,026
Mark-to-market liabilities(5)		—	3,961	3,961	1,629
Other	2015-2021	1,215	1,906	3,121	3,546
Total		$ 129,647	$ 1,112,740	$ 1,242,387	$ 1,040,071
Regulatory Liabilities:					
Income taxes		$ —	$ 55,490	$ 55,490	$ 55,017
Energy efficiency program costs(3)		—	—	—	6,686
Power supply costs(3)	Varies	1	—	1	24
Settlement agreement sharing mechanism(3)	2015-2016	7,999	—	7,999	7,602
Mark-to-market assets(5)		—	1,880	1,880	1,672
Other		3,114	922	4,036	3,470
Total		$ 11,114	$ 58,292	$ 69,406	$ 74,471

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.

(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 10.

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

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

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

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

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

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

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

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a load change adjustment rate, which is intended to ensure that power supply expense fluctuations resulting solely from load changes do not distort the results of the mechanism.

The table below summarizes the two most recent Idaho PCA rate adjustments, all of which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	$ Change (millions)	Notes
June 1, 2014	$ (88.2)	2014 PCA rates are net of (a) $20.0 million of surplus Idaho energy efficiency rider funds, and (b) $7.6 million of customer revenue sharing under a regulatory settlement stipulation. In addition, on June 1, 2014, there was an increase in base net power supply costs that shifted $99.3 million in power supply expenses from recovery via the PCA mechanism to recovery via base rates. See further discussion of the change in base net power supply costs below.
June 1, 2013	$ 140.4	The 2013 PCA rate increase was net of $7.2 million of customer revenue sharing under regulatory settlement stipulations.

On November 1, 2013, Idaho Power filed an application with the IPUC requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that would become effective June 1, 2014. Idaho Power's request was intended to remove the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead collect that portion through base rates. On March 21, 2014, the IPUC issued an order approving Idaho Power's application, with the change in collection methodology effective June 1, 2014.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual Oregon-jurisdictional return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2014 and 2013 are summarized in the table that follows:

Year and Mechanism	**APCU or PCAM Adjustment**
2014 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.
2013 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2013 APCU	A rate increase of $2.9 million annually took effect June 1, 2013.

Idaho Regulatory Matters

Idaho Base Rate Changes: Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from IPUC approval of a settlement stipulation that provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. Idaho base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Neither the settlement stipulation nor the IPUC orders adjusting base rates specified an authorized rate of return on equity or imposed a moratorium on Idaho Power filing a general rate case at a future date.

As noted above in this Note 3, the IPUC also issued a March 2014 order approving Idaho Power's request for an increase in the normalized or "base level" net power supply expense to be used to update base rates and in the determination of the Idaho PCA rate that would become effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that provided as follows:

- If Idaho Power's actual Idaho-jurisdiction return on year-end equity (Idaho ROE) for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year.

- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA mechanism adjustment.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

As Idaho Power's Idaho ROE exceeded 10.5 percent for 2013 and 2014, Idaho Power did not amortize additional ADITC for those years, but instead shared a portion of its Idaho-jurisdiction earnings with Idaho customers. The amounts Idaho Power recorded in 2013 and 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation were as follows (in millions):

Year	**Recorded as Refunds to Customers**	**Recorded as a Pre-tax Charge to Pension Expense**
2014	$8.0	$16.7
2013	$7.6	$16.5

October 2014 Idaho Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation are as follows:

- If Idaho Power's annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.5 percent Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.0 percent, the amount of earnings exceeding a 10.0 percent Idaho ROE and up to and including a 10.5 percent Idaho ROE will be allocated 75 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment and 25 percent to Idaho Power.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.5 percent, the amount of earnings exceeding a 10.5 percent Idaho ROE will be allocated 50 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to Idaho Power's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be adjusted prospectively.

Neither the settlement stipulation nor the associated IPUC order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the term of the settlement stipulation.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA mechanism is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual (weather-normalized) fixed costs recovered by Idaho Power during the year. The amount of the FCA recovery is capped at no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The following table summarizes FCA amounts approved for collection in the prior two FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

On July 1, 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA mechanism. Concerns cited by interested parties included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA mechanism is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. Proceedings in the FCA mechanism docket, which remains open, could result in significant changes to the FCA mechanism.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. The December 2011 IPUC general rate case settlement order described above reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date. As of December 31, 2014, the Idaho energy efficiency rider balance was a regulatory asset of $0.8 million.

On June 12, 2013, the IPUC issued an order authorizing Idaho Power to recover custom efficiency program incentive payments, including the then-current regulatory asset balance of approximately $14 million, as well as subsequent custom efficiency program incentive payments, through the Idaho energy efficiency rider mechanism. As a result of the order, Idaho Power recognized the balance as other revenue and energy efficiency program expenses in 2013.

Oregon Regulatory Matters

Oregon Base Rate Changes: On February 23, 2012, the OPUC issued an order approving a settlement stipulation that provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. Subsequently, on September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

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

Applicable Period	OATT Rate (per kW-year)
October 1, 2014 to September 30, 2015	$ 22.71
October 1, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.32

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $120.8 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. LONG-TERM DEBT

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

	2014	2013
First mortgage bonds:		
6.025% Series due 2018	$ 120,000	$ 120,000
6.15% Series due 2019	100,000	100,000
4.50% Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	100,000
2.95% Series due 2022	75,000	75,000
2.50% Series due 2023	75,000	75,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	75,000
4.00% Series due 2043	75,000	75,000
Total first mortgage bonds	1,425,000	1,425,000
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	3,191	4,255
Unamortized premium/discount - net	(3,034)	(3,278)
Total Idaho Power outstanding debt(2)	1,615,502	1,616,322
Current maturities of long-term debt	(1,064)	(1,064)
Total long-term debt	$ 1,614,438	$ 1,615,258

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2014 to $1.591 billion.

(2) At December 31, 2014 and 2013, the overall effective cost of Idaho Power's outstanding debt was 5.19 percent.

At December 31, 2014, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2015	2016	2017	2018	2019	Thereafter
$ 1,064	$ 1,064	$ 1,064	$ 120,000	$ 100,000	$ 1,395,344

Long-Term Debt Issuances, Maturities, and Availability

On April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds, Series I, maturing on April 1, 2023, and $75 million in principal amount of 4.00% first mortgage bonds, Series I, maturing on April 1, 2043. On October 1, 2013, Idaho Power used a portion of the net proceeds of the April 2013 sale of first mortgage bonds to satisfy its obligations upon maturity of $70 million in principal amount of 4.25% first mortgage bonds.

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

In anticipation of the expiration of the prior registration statement, on May 22, 2013, IDACORP and Idaho Power filed a joint shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of, in the case of Idaho Power, an unspecified principal amount of its first mortgage bonds and debt securities. On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds, secured medium term notes, Series J (Series J Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes pursuant to the Indenture. As of December 31, 2014, Idaho Power had not sold any first mortgage bonds, including Series J Notes, or debt securities under the Selling Agency Agreement.

***Mortgage*:** As of December 31, 2014, Idaho Power could issue under its Indenture approximately $1.6 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Indenture.

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

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

5. NOTES PAYABLE

Credit Facilities

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

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

At December 31, 2014, no loans were outstanding under Idaho Power's facility. At December 31, 2014, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of Idaho Power's short-term borrowings were as follows at December 31, 2014 and December 31, 2013:

	2014	2013
Commercial paper balances:		

At the end of year	$	—	$	—
Average during the year	$	—	$	2,209
Weighted-average interest rate				
At the end of the year		—%		—%

6. COMMON STOCK

Idaho Power Common Stock

No contributions were made to Idaho Power in 2014 or 2013, and no additional shares of Idaho Power common stock were issued.

Restrictions on Dividends

Idaho Power's ability to pay dividends on its common stock held by IDACORP is limited to the extent payment of such dividends would violate the covenants in the credit facility or Idaho Power's Revised Code of Conduct. A covenant under Idaho Power's credit facility requires Idaho Power to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2014, the leverage ratio for Idaho Power was 47 percent. Based on these restrictions, Idaho Power's dividends were limited to $944 million at December 31, 2014. There are additional facility covenants, subject to exceptions, that prohibit or restrict the sale or disposition of property without consent and any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2014, Idaho Power was in compliance with those covenants.

Idaho Power's Revised Policy and Code of Conduct relating to transactions between and among Idaho Power, IDACORP, and other affiliates, which was approved by the IPUC in April 2008, provides that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2014, Idaho Power's common equity capital was 53 percent of its total adjusted capital. Further, Idaho Power must obtain approval from the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

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

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the Federal Power Act or its regulations, but Idaho Power does not believe the restriction would limit Idaho Power's ability to pay dividends out of current year earnings or retained earnings.

In accordance with Section 10(d) of the Federal Power Act, Idaho Power has $13.3 million of amortization reserves established for certain of its licensed hydroelectric facilities.

7. STOCK-BASED COMPENSATION

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

The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP (for officers and key employees) permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2014, the maximum number of shares available under the LTICP and RSP were 1,166,210 and 15,796, respectively, excluding (i) issued but unvested performance-based restricted shares and (ii) issued but unvested time-based restricted shares.

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

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. The performance conditions are two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. Depending on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The grant-date fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The grant-date fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock and performance share activity is presented below. Share amounts represent the shares of IDACORP common stock:

	Number of Shares	**Weighted-Average Grant Date Fair Value**
Nonvested shares at January 1, 2014	305,984	$ 36.85
Shares granted	105,367	48.74
Shares forfeited	(35,298)	46.34
Shares vested	(125,657)	30.09
Nonvested shares at December 31, 2014	**250,396**	**$ 43.91**

The total fair value of shares vested during the years ended December 31, 2014 and 2013 was $6.6 million and $5.0 million, respectively. At December 31, 2014, Idaho Power had $4.6 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 1.69 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2014, a total of 14,599 of IDACORP common stock shares were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $56.05 per share. Directors elected to defer receipt of 8,004 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: IDACORP has not granted any stock option awards since 2006 and has no plans to do so in the future. At December 31, 2014, there were no outstanding options.

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

	2014	**2013**
Compensation cost	$ 5,458	$ 4,783
Income tax benefit	2,134	1,870

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2014, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2015	**2016**	**2017**	**2018**	**2019**	**Thereafter**
Cogeneration and power production	$ 181,468	$ 189,493	$ 229,255	$ 240,280	$ 238,501	$ 4,064,213
Power and transmission rights	6,370	5,416	3,337	1,199	1,105	4,487
Fuel	64,415	42,124	41,744	9,352	9,169	68,359

As of December 31, 2014, Idaho Power had 781 MW nameplate capacity of PURPA-related projects on-line, with an additional 521 MW nameplate capacity of projects projected to be on-line by June 1, 2017. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. Idaho Power's expenses associated with PURPA-related projects were approximately $145 million in 2014 and $131 million in 2013.

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

	2015	**2016**	**2017**	**2018**	**2019**	**Thereafter**
Operating leases	$ 162	$ 1,039	$ 1,065	$ 1,088	$ 1,167	$ 14,136
Equipment, maintenance, and service agreements	61,492	19,610	8,279	7,794	7,978	31,489
FERC and other industry-related fees	12,954	6,813	6,813	6,813	6,813	34,063

Idaho Power's expense for operating leases was approximately $5.8 million in 2014 and $5.2 million in 2013.

Guarantees

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was $70 million at December 31, 2014, representing IERCo's one-third share of BCC's total reclamation obligation. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2014, the value of the reclamation trust fund was $67 million. During 2014 the reclamation trust fund distributed approximately $13 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on historical experience and the evaluation of the specific indemnities. As of December 31, 2014, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability within the consolidated balance sheet with respect to these indemnification obligations.

9. CONTINGENCIES

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

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United

States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending proceedings and predict that these matters will not have a material adverse effect on Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds in the Pacific Northwest markets from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC has characterized these ripple claims as "speculative." However, the FERC has refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve portions of two settlements that provided for waivers of claims in those proceedings, despite only limited objections from two market participants to one of the two settlements and no objections to the other settlement. Idaho Power and IESCo have petitions for review of the FERC's decisions refusing to approve the waiver provision of the settlements, on the basis that the FERC failed to apply its established precedents and rules. The petitions for review are pending in the Ninth Circuit Court of Appeals.

Based on its evaluation of the merits of ripple claims and the inability to estimate the potential exposure should the claims ultimately have any merit, particularly in light of Idaho Power and IESCo being both purchasers and sellers in the energy market during the relevant period, Idaho Power and IESCo have no amount accrued relating to the proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Other Proceedings

Idaho Power is party to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the company believes that resolution of those matters will not have a material adverse effect on the consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations, including the EPA's proposed rule under Section 111(d) of the Clean Air Act, that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to estimate the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

10. BENEFIT PLANS

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

Pension Plans

Idaho Power has two pension plans – a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit pension plan for certain senior management employees called the Security Plan for Senior Management Employees (SMSP). Idaho Power also has a nonqualified defined benefit pension plan for directors that was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power’s funding policy for the pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2014 and

2013 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013
Change in benefit obligation:				
Benefit obligation at January 1	$ 695,093	$ 767,692	$ 77,773	$ 80,515
Service cost	25,292	31,357	1,645	2,178
Interest cost	35,415	31,830	3,856	3,258
Actuarial loss (gain)	114,496	(112,215)	15,324	(4,663)
Benefits paid	(25,484)	(23,571)	(4,188)	(3,515)
Projected benefit obligation at December 31	844,812	695,093	94,410	77,773
Change in plan assets:				
Fair value at January 1	545,092	460,862	—	—
Actual return on plan assets	10,111	77,801	—	—
Employer contributions	30,000	30,000	—	—
Benefits paid	(25,484)	(23,571)	—	—
Fair value at December 31	559,719	545,092	—	—
Funded status at end of year	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,193)	$ (3,905)
Noncurrent liabilities	(285,093)	(150,001)	(90,217)	(73,868)
Net amount recognized	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 263,350	$ 120,587	$ 38,808	$ 26,102
Prior service cost	295	642	857	1,077
Subtotal	263,645	121,229	39,665	27,179
Less amount recorded as regulatory asset	(263,645)	(121,229)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 39,665	$ 27,179
Accumulated benefit obligation	$ 719,617	$ 591,649	$ 84,684	$ 70,530

The actuarial loss affecting the change in projected benefit obligations from December 31, 2013 to December 31, 2014 is due to the reduction in the discount rates, as identified in the plan assumptions table included later in this footnote.

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. The fair value of these investments was approximately $65.0 million and $59.2 million at December 31, 2014 and 2013, respectively, and is reflected in Investments and in Company-owned life insurance on the consolidated balance sheets.

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

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013
Service cost	$ 25,292	$ 31,357	$ 1,645	$ 2,178

Interest cost	35,415	31,830	3,856	3,258
Expected return on plan assets	(42,289)	(35,755)	—	—
Amortization of net loss	3,911	17,118	2,618	2,840
Amortization of prior service cost	347	347	220	212
Net periodic pension cost	22,676	44,897	8,339	8,488
Adjustments due to the effects of regulation(1)	12,124	(9,013)	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,800	$ 35,884	$ 8,339	$ 8,488

(1) Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates.

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

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013
Actuarial (loss) gain during the year	$ (146,674)	$ 154,261	$ (15,324)	$ 4,664
Reclassification adjustments for:				
Amortization of net loss	3,911	17,118	2,618	2,840
Amortization of prior service cost	347	347	220	212
Adjustment for deferred tax effects	55,678	(67,136)	4,881	(3,017)
Adjustment due to the effects of regulation	86,738	(104,590)	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ (7,605)	$ 4,699

In 2015, Idaho Power expects to recognize as components of net periodic benefit cost $18.8 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2014, relating to the pension plan and SMSP. This amount consists of $14.2 million of amortization of net loss and $0.2 million of amortization of prior service cost for the pension plan, and $4.2 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2015	2016	2017	2018	2019	2020-2024
Pension Plan	$ 27,634	$ 29,938	$ 32,428	$ 35,036	$ 37,644	$ 226,411
SMSP	4,274	4,198	4,262	4,134	4,291	23,868

As of December 31, 2014, Idaho Power's minimum required contribution to the pension plan is estimated to be zero in 2015, though Idaho Power plans to contribute at least $20 million to the pension plan during 2015.

Postretirement Benefits

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

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

	2014	2013
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 57,341	$ 72,547
Service cost	1,011	1,315
Interest cost	2,841	2,633
Actuarial loss (gain)	7,026	(16,788)
Benefits paid[1]	(2,220)	(2,366)
Benefit obligation at December 31	65,999	57,341
Change in plan assets:		
Fair value of plan assets at January 1	37,111	33,387
Actual return on plan assets	3,888	6,212
Employer contributions[1]	(404)	(122)
Benefits paid[1]	(2,220)	(2,366)
Fair value of plan assets at December 31	38,375	37,111
Funded status at end of year (included in noncurrent liabilities)	$ (27,624)	$ (20,230)

[1] Contributions and benefits paid are each net of $3,379 thousand and $3,272 thousand of plan participant contributions, and $344 thousand and $372 thousand of Medicare Part D subsidy receipts for 2014 and 2013, respectively.

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

	2014	2013
Net loss	$ 759	$ (4,974)
Prior service cost	145	328
Subtotal	904	(4,646)
Less amount recognized in regulatory assets	(904)	4,646
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2014	2013
Service cost	$ 1,011	$ 1,315
Interest cost	2,841	2,633
Expected return on plan assets	(2,595)	(2,328)
Amortization of net loss	—	98
Amortization of prior service cost	183	(229)
Amortization of unrecognzied transition obligation	—	—
Net periodic postretirement benefit cost	$ 1,440	$ 1,489

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

	2014	2013
Actuarial (loss) gain during the year	$ (5,733)	$ 20,673
Reclassification adjustments for:		
Amortization of net loss	—	98

Amortization of prior service cost	183	(229)
Adjustment for deferred tax effects	2,170	(8,031)
Adjustment due to the effects of regulation	3,380	(12,511)
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2015, Idaho Power expects to recognize as a component of net periodic benefit cost $15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents $15 thousand of amortization of prior service cost.

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

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

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	$ 3,970	$ 4,040	$ 4,090	$ 4,160	$ 4,210	$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

Plan Assumptions

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

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013	Postretirement Benefits 2014	Postretirement Benefits 2013
Discount rate	4.25 %	5.20 %	4.20 %	5.10 %	4.20 %	5.15 %
Rate of compensation increase(1)	4.30 %	4.38 %	4.50 %	4.50 %	—	—
Medical trend rate	—	—	—	—	6.4 %	6.8 %
Dental trend rate	—	—	—	—	5.0 %	5.0 %
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

(1) The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

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

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013	Postretirement Benefits 2014	Postretirement Benefits 2013
Discount rate	5.20 %	4.20 %	5.10 %	4.15 %	5.15 %	4.20 %
Expected long-term rate of return on assets	7.75 %	7.75 %	—	—	7.25 %	7.25 %
Rate of compensation increase	4.30 %	4.38 %	4.50 %	4.50 %	—	—

Medical trend rate	—	—	—	—	6.4 %	6.8 %
Dental trend rate	—	—	—	—	5.0 %	5.0 %

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 325	$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2014 for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2014
Debt securities	24 %	24 %
Equity securities	54 %	55 %
Real estate	6 %	6 %
Other plan assets	16 %	15 %
Total	100 %	100 %

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

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

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

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

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

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

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

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

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2014				
Pension plan assets:				
Cash and cash equivalents	$ 19,190	$ —	$ —	$ 19,190
Short-term bonds	—	10,991	—	10,991
Intermediate bonds	—	101,867	—	101,867
Long-term bonds	—	21,615	—	21,615
Equity Securities: Large-Cap	66,151	—	—	66,151
Equity Securities: Mid-Cap	68,974	—	—	68,974
Equity Securities: Small-Cap	50,972	—	—	50,972
Equity Securities: Micro-Cap	22,962	—	—	22,962
Equity Securities: International	6,555	57,705	—	64,260
Equity Securities: Emerging Markets	8,629	22,915	—	31,544
Real estate	—	—	33,996	33,996
Private market investments	—	—	37,118	37,118
Commodities funds	—	30,079	—	30,079
Total pension assets	$ 243,433	$ 245,172	$ 71,114	$ 559,719
Postretirement plan assets(1)	$ 11	$ 38,364	$ —	$ 38,375
Assets at December 31, 2013				
Pension plan assets:				
Cash and cash equivalents	$ 33,030	$ —	$ —	$ 33,030
Short-term bonds	—	11,068	—	11,068
Intermediate bonds	—	76,312	—	76,312
Long-term bonds	—	19,024	—	19,024
Equity Securities: Large-Cap	71,042	—	—	71,042
Equity Securities: Mid-Cap	23,346	23,112	—	46,458

Equity Securities: Small-Cap		48,998		—		—		48,998
Equity Securities: Micro-Cap		24,687		—		—		24,687
Equity Securities: International		19,128		74,908		—		94,036
Equity Securities: Emerging Markets		3,523		22,107		—		25,630
Equity Securities: Market Neutral		3,870		—		—		3,870
Real estate		—		—		28,019		28,019
Private market investments		—		—		33,709		33,709
Commodities funds		—		29,209		—		29,209
Total pension assets	$	227,624	$	255,740	$	61,728	$	545,092
Postretirement plan assets(1)	$	75	$	37,036	$	—	$	37,111

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

For the year ended December 31, 2014, the only significant transfer in and out of Levels 1, 2, or 3 was $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1. For the year ended December 31, 2013, there were no significant transfers into or out of Levels 1, 2, or 3.

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

		Private Equity		**Real Estate**		**Total**
Beginning balance - January 1, 2013	$	30,507	$	27,874	$	58,381
Realized gains		—		739		739
Unrealized gains		2,941		1,579		4,520
Purchases		89		4,726		4,815
Sales		—		(6,899)		(6,899)
Settlements		172		—		172
Ending balance - December 31, 2013		33,709		28,019		61,728
Realized gains		1,430		866		2,296
Unrealized (losses) gains		(545)		1,305		760
Purchases		2,434		3,806		6,240
Settlements		90		—		90
Ending balance - December 31, 2014	$	37,118	$	33,996	$	71,114

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

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

Level 2 Postretirement Assets: These assets represent an investment in a life insurance contract and are recorded at fair value, which is the cash surrender value, less any unpaid expenses. The cash surrender value of this insurance contract is contractually equal to the insurance contract's proportionate share of the market value of an associated investment account held by the insurer. The investments held by the insurer's investment account are all instruments traded on exchanges with readily determinable market prices.

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

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

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

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately $7 million each year for 2013 and 2014.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on Idaho Power's consolidated balance sheet at December 31, 2014 and 2013 is $2.0 million and $1.9 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 2014 and 2013 (in thousands of dollars):

	2014 Balance	2014 Avg Rate	2013 Balance	2013 Avg Rate
Production	$ 2,316,941	2.48 %	$ 2,272,381	2.47 %
Transmission	1,016,207	2.03 %	974,697	2.01 %
Distribution	1,516,933	2.72 %	1,459,666	2.72 %
General and Other	398,131	5.49 %	373,658	5.91 %
Total in service	5,248,212	2.68 %	5,080,402	2.69 %
Accumulated provision for depreciation	(2,021,074)		(1,940,654)	
In service - net	$ 3,227,138		$ 3,139,748	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses for each facility is included in the Consolidated Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power’s participation, were as follows at December 31, 2014 (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	$ 569,220	$ 59,394	$ 293,432	33	771
Boardman	Boardman, OR	80,951	125	60,031	10	64
Valmy Units 1 and 2	Winnemucca, NV	372,791	19,023	193,756	50	284

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

IERCo, Idaho Power’s wholly-owned subsidiary, is a joint venture in BCC. Idaho Power’s coal purchases from the joint venture were $79 million in 2014 and 2013.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power’s power purchases from these facilities were $9 million each year for 2013 and 2014.

12. ASSET RETIREMENT OBLIGATIONS (ARO)

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

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyl-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2014, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net decrease of $4.1 million in the recorded AROs. The decrease in the AROs in 2014 is primarily due to decreases in estimated future costs related to evaporation ponds at the Valmy generating facility.

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

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

	2014	2013
Balance at beginning of year	$ 25,765	$ 22,982
Accretion expense	1,061	1,041
Revisions in estimated cash flows	(4,140)	2,722
Liability settled	(756)	(980)
Balance at end of year	$ 21,930	$ 25,765

13. INVESTMENTS

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

	2014	2013
Idaho Power investments:		
IERCo	$ 83,477	$ 91,385
Available-for-sale equity securities	44,942	41,119
Executive deferred compensation plan investments	141	1,153
Other investments	1	1
Total Idaho Power investments	128,561	133,658

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value. Any unrealized gains or losses on available-for-sale securities are included in income, as the fair value option has been elected for these instruments. Unrealized gains and losses on available-for-sale securities were immaterial at December 31, 2014 and December 31, 2013.

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

	2014	2013
Proceeds from sales	$ —	$ 25,661
Gross realized gains from sales	—	11,637
Gross realized losses from sales	—	—

At the end of each reporting period, Idaho Power analyzes securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2014 and December 31, 2013, there were no indicators of other-than-temporary impairment related to Idaho Power's investments.

14. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

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

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges. Idaho Power offsets fair value amounts recognized on its balance sheet and applies collateral related to derivative instruments executed with the same counterparty under the same master netting agreement. Idaho Power does not offset a counterparty's current derivative contracts with the counterparty's long-term derivative contracts, although Idaho Power's master netting arrangements would allow current and long-term positions to be offset in the event of default. Also, in the event of default, Idaho Power's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting presented in the derivative fair value and offsetting table below.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31, 2014 and 2013 (in thousands of dollars):

Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss on Derivatives Recognized in Income(1) 2014	Gain/(Loss on Derivatives Recognized in Income(1) 2013

Financial swaps	Off-system sales	$ (4,119)	$ (2,637)
Financial swaps	Purchased power	(1,416)	947
Financial swaps	Fuel expense	3,862	731
Financial swaps	Other operations and maintenance	(158)	35
Forward contracts	Off-system sales	277	185
Forward contracts	Purchased power	(279)	(196)
Forward contracts	Fuel expense	94	217

(1) Excludes unrealized gains or losses on derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

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

Derivative Instrument Summary

The table below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets and reconciles the gross amounts of derivatives recognized as assets and as liabilities to the net amounts presented in the balance sheets at December 31, 2014 and 2013 (in thousands of dollars):

	Balance Sheet Location	**Asset Derivatives Gross Fair Value**	**Asset Derivatives Amounts Offset**	**Asset Derivatives Net Assets**
December 31, 2014				
Current:				
Financial swaps	Other current assets	$ 2,509	$ (2,002)(1)	$ 507
Financial swaps	Other current liabilities	379	(379)	—
Forward contracts	Other current assets	64	—	64
Forward contracts	Other current liabilities	—	—	—
Long-term:				
Forward contracts	Other assets	63	—	63
Total		$ 3,015	$ (2,381)	$ 634
December 31, 2013				
Current:				
Financial swaps	Other current assets	$ 1,451	$ (175)	$ 1,276
Financial swaps	Other current liabilities	373	(373)	0
Forward contracts	Other current assets	109	—	109
Forward contracts	Other current liabilities	—	—	0
Long-term:				
Financial swaps	Other assets	189	(28)	161
Forward contracts	Other assets	126	—	126
Total		$ 2,248	$ (576)	$ 1,672

	Balance Sheet Location	**Liability Derivatives Gross Fair Value**	**Liability Derivatives Amounts Offset**	**Liability Derivatives Net Assets**
December 31, 2014				
Current:				

Financial swaps	Other current assets	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	4,335	(379)	3,956
Forward contracts	Other current assets	—	—	—
Forward contracts	Other current liabilities	5	—	5
Long-term:				
Forward contracts	Other assets	—	—	—
Total		$ 5,096	$ (1,135)	$ 3,961
December 31, 2013				
Current:				
Financial swaps	Other current assets	$ 175	$ (175)	$ —
Financial swaps	Other current liabilities	1,975	(1,429)(1)	546
Forward contracts	Other current assets	—	—	—
Forward contracts	Other current liabilities	26	—	26
Long-term:				
Financial swaps	Other assets	28	(28)	—
Forward contracts	Other assets	—	—	—
Total		$ 2,204	$ (1,632)	$ 572

(1) Current asset and current liability derivative amounts offset include $1.2 million and $1.1 million of collateral payable and receivable for the periods ending December 31, 2014 and 2013, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2014 and 2013 (in thousands of units):

Commodity	Units	December 31, 2014	December 31, 2013
Electricity purchases	MWh	115	89
Electricity sales	MWh	238	603
Natural gas purchases	MMBtu	6,913	10,804
Natural gas sales	MMBtu	409	555
Diesel purchases	Gallons	243	906

Credit Risk

At December 31, 2014, Idaho Power did not have material credit risk exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power’s physical power contracts are commonly under Western Systems Power Pool agreements, physical gas contracts are usually under North American Energy Standards Board contracts, and financial transactions are usually under International Swaps and Derivatives Association, Inc. contracts. These contracts contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2014, was $5.1 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2014, Idaho Power would have been required to post an additional $5.9 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

Idaho Power's assessment of a particular input's significance 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. An item recorded at fair value is reclassified among levels when changes in the nature of valuation inputs cause the item to no longer meet the criteria for the level in which it was previously categorized. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2014 and 2013.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2014 and 2013 (in thousands of dollars):

	December 31, 2014				December 31, 2013			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								

Derivatives	$ 506	$ 128	$ —	$ 634	$ 1,437	$ 235	$ —	$ 1,672
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	141	—	—	141	1,153	—	—	1,153
Available-for-sale securities: Equity securities	44,942	—	—	44,942	41,119	—	—	41,119
Liabilities:								
Derivatives	$ 17	$ 3,944	$ —	$ 3,961	$ 546	$ 26	$ —	$ 572

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

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2014 and 2013, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2014		**December 31, 2013**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Liabilities:				
Long-term debt(1)	$ 1,615,502	$ 1,788,197	$ 1,616,322	$ 1,600,248

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

Long-term debt is not traded on an exchange and is valued using quoted rates for similar debt in active markets. Carrying values for cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued approximate fair value.

16. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to the SMSP. The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2014 and 2013 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Unrealized Gains and Losses on Available-for-Sale Securities	**Defined Benefit Pension Items**	**Total**
December 31, 2014			
Balance at beginning of period	$ —	$ (16,553)	$ (16,553)
Other comprehensive income before reclassifications	—	(9,333)	(9,333)
Amounts reclassified from AOCI	—	1,728	1,728
Net current-period other comprehensive income	—	(7,605)	(7,605)

Balance at end of period	$ —	$ (24,158)	$ (24,158)
December 31, 2013			
Balance at beginning of period	$ 4,136	$ (21,252)	$ (17,116)
Other comprehensive income before reclassifications	2,951	2,840	5,791
Amounts reclassified from AOCI	(7,087)	1,859	(5,228)
Net current-period other comprehensive income	(4,136)	4,699	563
Balance at end of period	$ —	$ (16,553)	$ (16,553)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2014 and 2013 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI 2014	Amount Reclassified from AOCI 2013
Unrealized gains on available-for-sale securities		
Realized gain on sale of securities, before tax[1]	$ —	$ (11,637)
Tax benefit[2]	—	4,550
Net of tax	—	(7,087)
Amortization of defined benefit pension items[3]		
Prior service cost	220	212
Net loss	2,618	2,839
Total before tax	2,838	3,051
Tax benefit[2]	(1,110)	(1,192)
Net of tax	1,728	1,859
Total reclassification for the period	$ 1,728	$ (5,228)

(1) The realized gain is included in Idaho Power's consolidated income statement in other income (expense), net.

(2) The tax benefit is included in income tax expense (benefit) in the consolidated income statement of Idaho Power.

(3) Amortization of these items is included in Idaho Power's consolidated income statement in other expense, net.

17. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $1.4 million in 2014 and $1.0 million in 2013.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million to Ida-West in each year for 2013 and 2014.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	4,136,553			(21,252,222)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(7,087,026)			1,858,601
3	Preceding Quarter/Year to Date Changes in Fair Value	2,950,473			2,840,246
4	Total (lines 2 and 3)	(4,136,553)			4,698,847
5	Balance of Account 219 at End of Preceding Quarter/Year				(16,553,375)
6	Balance of Account 219 at Beginning of Current Year				(16,553,375)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,728,379
8	Current Quarter/Year to Date Changes in Fair Value				(9,333,003)
9	Total (lines 7 and 8)				(7,604,624)
10	Balance of Account 219 at End of Current Quarter/Year				(24,157,999)

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			(17,115,669)	[redacted]	[redacted]
2			(5,228,425)	[redacted]	[redacted]
3			5,790,719	[redacted]	[redacted]
4			562,294	176,741,143	177,303,437
5			(16,553,375)	[redacted]	[redacted]
6			(16,553,375)	[redacted]	[redacted]
7			1,728,379	[redacted]	[redacted]
8			(9,333,003)	[redacted]	[redacted]
9			(7,604,624)	189,386,993	181,782,369
10			(24,157,999)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,248,212,331	5,248,212,331
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,248,212,331	5,248,212,331
9	Leased to Others		
10	Held for Future Use	7,090,431	7,090,431
11	Construction Work in Progress	401,929,509	401,929,509
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,657,232,271	5,657,232,271
14	Accum Prov for Depr, Amort, & Depl	2,021,073,827	2,021,073,827
15	Net Utility Plant (13 less 14)	3,636,158,444	3,636,158,444
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,997,908,418	1,997,908,418
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	23,165,409	23,165,409
22	Total In Service (18 thru 21)	2,021,073,827	2,021,073,827
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,021,073,827	2,021,073,827

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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					32
					33

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
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			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	29,492,883	-196,102
4	(303) Miscellaneous Intangible Plant	32,001,618	2,704,134
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	61,500,204	2,508,032
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,707,109	5,099
9	(311) Structures and Improvements	147,607,746	5,720,605
10	(312) Boiler Plant Equipment	574,685,386	30,968,367
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	157,130,004	2,456,602
13	(315) Accessory Electric Equipment	69,526,524	625,133
14	(316) Misc. Power Plant Equipment	16,424,380	535,355
15	(317) Asset Retirement Costs for Steam Production	10,045,806	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	977,126,955	40,311,161
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	30,921,432	267,825
28	(331) Structures and Improvements	172,021,110	3,009,623
29	(332) Reservoirs, Dams, and Waterways	253,221,758	9,357,143
30	(333) Water Wheels, Turbines, and Generators	201,680,871	5,615,318
31	(334) Accessory Electric Equipment	52,291,611	4,995,191
32	(335) Misc. Power PLant Equipment	21,004,289	812,228
33	(336) Roads, Railroads, and Bridges	8,183,435	1,401,205
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	739,324,506	25,458,533
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	133,753,938	7,148,416
39	(342) Fuel Holders, Products, and Accessories	7,982,028	2,470,519
40	(343) Prime Movers	236,639,588	4,939,595
41	(344) Generators	73,353,524	-6,998,268
42	(345) Accessory Electric Equipment	95,671,190	-7,063,625
43	(346) Misc. Power Plant Equipment	5,839,469	407,924
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	555,929,743	904,561
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,272,381,204	66,674,255

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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	36,087,730	102,069
49	(352) Structures and Improvements	70,075,081	2,716,121
50	(353) Station Equipment	388,935,103	13,971,575
51	(354) Towers and Fixtures	162,004,612	6,341,023
52	(355) Poles and Fixtures	129,115,202	14,311,741
53	(356) Overhead Conductors and Devices	188,088,876	9,279,054
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	390,266	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	974,696,870	46,721,583
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,859,147	316,069
61	(361) Structures and Improvements	32,820,611	913,719
62	(362) Station Equipment	196,765,816	5,794,037
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	235,549,416	7,425,968
65	(365) Overhead Conductors and Devices	126,034,768	3,619,432
66	(366) Underground Conduit	46,289,611	1,157,996
67	(367) Underground Conductors and Devices	207,476,280	12,302,488
68	(368) Line Transformers	471,882,211	28,734,467
69	(369) Services	56,858,427	1,369,592
70	(370) Meters	73,143,443	7,766,427
71	(371) Installations on Customer Premises	2,901,563	94,180
72	(372) Leased Property on Customer Premises	-38,361	2,302
73	(373) Street Lighting and Signal Systems	4,588,849	
74	(374) Asset Retirement Costs for Distribution Plant	533,712	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,459,665,493	69,496,677
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	16,579,675	-4,824
87	(390) Structures and Improvements	102,938,584	4,701,008
88	(391) Office Furniture and Equipment	40,898,058	7,308,118
89	(392) Transportation Equipment	67,727,230	6,807,324
90	(393) Stores Equipment	1,908,757	45,847
91	(394) Tools, Shop and Garage Equipment	7,196,937	616,301
92	(395) Laboratory Equipment	12,444,681	806,460
93	(396) Power Operated Equipment	12,801,276	1,136,844
94	(397) Communication Equipment	43,926,012	12,801,448
95	(398) Miscellaneous Equipment	5,736,818	265,832
96	SUBTOTAL (Enter Total of lines 86 thru 95)	312,158,028	34,484,358
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)	312,158,028	34,484,358
100	TOTAL (Accounts 101 and 106)	5,080,401,799	219,884,905
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)	5,080,401,799	219,884,905

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
			29,296,781		3
5,078,245			29,627,507		4
5,078,245			58,929,991		5
					6
					7
			1,712,208		8
3,243,987			150,084,364		9
10,490,606			595,163,147		10
					11
249,879			159,336,727		12
108,610			70,043,047		13
1,024,920			15,934,815		14
	-3,673,688		6,372,118		15
15,118,002	-3,673,688		998,646,426		16
					17
					18
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					26
		-916	31,188,341		27
28,310			175,002,423		28
			262,578,901		29
105,628			207,190,561		30
458,911			56,827,891		31
46,595			21,769,922		32
			9,584,640		33
					34
639,444		-916	764,142,679		35
					36
			2,690,006		37
			140,902,354		38
			10,452,547		39
2,682,736			238,896,447		40
			66,355,256		41
			88,607,565		42
			6,247,393		43
					44
2,682,736			554,151,568		45
18,440,182	-3,673,688	-916	2,316,940,673		46

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
40,945		-2,730	36,146,124		48
68,593		15,382	72,737,991		49
3,103,709		-15,001	399,787,968		50
158,783			168,186,852		51
829,288			142,597,655		52
1,007,330			196,360,600		53
					54
					55
			390,266		56
					57
5,208,648		-2,349	1,016,207,456		58
					59
		-85	5,175,131		60
34,476		16,845	33,716,699		61
497,312		-32,341	202,030,200		62
					63
1,887,005			241,088,379		64
1,646,176			128,008,024		65
153,281			47,294,326		66
1,122,161			218,656,607		67
6,001,802			494,614,876		68
360,634			57,867,385		69
381,296			80,528,574		70
64,373		-16,845	2,914,525		71
48,289			-84,348		72
			4,588,849		73
			533,712		74
12,196,805		-32,426	1,516,932,939		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		3,731	16,578,582		86
585,872		-15,382	107,038,338		87
2,303,414			45,902,762		88
320,179			74,214,375		89
18,207			1,936,397		90
238,458			7,574,780		91
612,914		14,262	12,652,489		92
			13,938,120		93
2,972,236		33,080	53,788,304		94
425,525			5,577,125		95
7,476,805		35,691	339,201,272		96
					97
					98
7,476,805		35,691	339,201,272		99
48,400,685	-3,673,688		5,248,212,331		100
					101
					102
					103
48,400,685	-3,673,688		5,248,212,331		104

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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
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47	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	04/15/2015	End of 2014/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		655,550
3	Production			109,961
4	Transmission Stations			423,089
5	Transmission Lines			195,489
6	Distribution Stations			1,077,217
7	Beacon Light Substation	12/30/02		465,662
8	Homedale Substation	2/29/08		109,453
9	North River Operations Center	1/31/08		2,630,412
10	Line #854 500 Kv	3/31/09		308,066
11				
12				
13				
14	Column B if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Transmission Stations			199,069
24	Distribution Stations			69,941
25	Homedale Substation	2/29/08		217,797
26	Beacon Light Substation	12/30/02		555,940
27				
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47	Total			7,090,431

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ROLLUP RELIC COST BROWNLEE	79,830,017
2	ROLLUP RELIC COST HELLS CANYON	54,409,576
3	GATEWAY WEST 500KV LINE	26,705,505
4	BRIDGER 2011C038 JB3 SCR SYS D	26,503,011
5	ROLLUP RELIC COST OXBOW	25,260,594
6	BOARDMAN - HEMINGWAY 500 KV LI	21,460,986
7	HELLS CANYON RELICENSING OUTSI	20,296,218
8	BRIDGER 2011C039 JB4 SCR SYS D	17,320,740
9	CIAC LIABILITY RECLASS	10,570,351
10	BROWNLEE TURBINE REFURBISHMENT	8,913,910
11	B2H PERMITTING 11/1/2011 & FOR	7,534,197
12	BRIDGER UNDISTRIBUTED WORK ORD	5,358,000
13	VALMY 98281993 V2 COOLING TOWE	4,984,852
14	VALMY UNDISTRIBUTED WORK ORDER	3,964,000
15	VALMY 98306281V2 SCRUBBER INLE	3,489,100
16	MPSN REPLACE C232&C233 SERIES	2,798,630
17	VALMY 98306280 V2 SCRUBBER SPR	2,777,076
18	LEGAL DEPT. LABOR FOR RELICENS	2,711,029
19	LOWER SALMON RUNNER REPLACEMEN	2,369,744
20	REL-HCC OREGON REAUTHORIZATION	2,327,924
21	B2H TLINE CONSTRUCTION COSTS	2,286,270
22	HCC WATERSHED ENHANCEMENT PROG	2,213,993
23	CORPORATE AIRPLANE ENGINE REPL	2,102,511
24	CHQB100177 - SPARE XFRMR LANGL	1,963,324
25	BRIDGER 2012C075 U1 MERCURY CO	1,821,189
26	BRIDGER 2012C076 U2 MERCURY CO	1,813,914
27	BRIDGER 2012C078 U4 MERCURY CO	1,805,544
28	BRIDGER 2012C077 U3 MERCURY CO	1,800,943
29	HCPR110116 REPL T233 GSU	1,624,495
30	PAYROLL & IBNR ACCRUAL	1,545,259
31	BRIDGER 2014C037 U3 REPLACE FI	1,476,314
32	HBND-041:ALT LINE ROUTE TO GAR	1,316,817
33	WQ HCC401 APPLICATION, REVISIO	1,279,798
34	WDRI-KCHM NEW 138KV	1,273,198
35	TNDY ADD 69 KV BREAKERS EXPAND	1,213,293
36	RELICENSING: BAKER COUNTY SETT	1,200,163
37	REC - BAKER COUNTY SETTLEMENT	1,120,300
38	WQ HCC401 CERTIFICATION OPS AN	1,083,319
39	314 DESIGN TEAMS - CAPITAL - C	1,068,315
40	FALL CHINOOK PROGRAM - REDD SU	1,067,075
41	OTHER MINOR PROJECTS UNDER $1,000,000	41,268,015
42		
43	TOTAL	401,929,509

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,919,582,910	1,919,582,910		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	125,245,540	125,245,540		
4	(403.1) Depreciation Expense for Asset Retirement Costs	495,029	495,029		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,723,850	3,723,850		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	102,213	102,213		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	129,566,632	129,566,632		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	43,281,494	43,281,494		
13	Cost of Removal	10,451,825	10,451,825		
14	Salvage (Credit)	1,921,106	1,921,106		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	51,812,213	51,812,213		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	CIAC, Reserve Adj and ARO activity.	571,089	571,089		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,997,908,418	1,997,908,418		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	541,682,229	541,682,229		
21	Nuclear Production				
22	Hydraulic Production-Conventional	390,670,339	390,670,339		
23	Hydraulic Production-Pumped Storage				
24	Other Production	72,501,209	72,501,209		
25	Transmission	312,623,040	312,623,040		
26	Distribution	567,894,311	567,894,311		
27	Regional Transmission and Market Operation				
28	General	112,537,290	112,537,290		
29	TOTAL (Enter Total of lines 20 thru 28)	1,997,908,418	1,997,908,418		

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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			88,921,479
5				
6	Subtotal Idaho Energy Resources Company			91,384,573
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	91,384,573

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
7,092,887	15,000,000	81,014,366		4
				5
7,092,887	15,000,000	83,477,460		6
				7
				8
				9
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7,092,887	15,000,000	83,477,460		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	41,546,323	55,170,482	Electric
2	Fuel Stock Expenses Undistributed (Account 152)		599	Electric
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)	16,506,169	17,010,420	
8	Transmission Plant (Estimated)	10,947,716	11,212,105	
9	Distribution Plant (Estimated)	20,538,847	20,564,459	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,274,973	1,518,495	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,267,705	50,305,479	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)	4,375,589	5,098,760	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	95,189,617	110,575,320	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
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								45
								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	04/15/2015	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
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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) 04/15/2015	Year/Period of Report End of 2014/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
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14						
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18						
19						
20	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	04/15/2015	End of 2014/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21						
22						
23						
24						
25						
26						
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43						
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47						
48						
49	TOTAL					

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	BLACK CANYON SISR	4,210	186623	(5,370)	186623
3	BPAP NETWORK SIS 78318516	2,776	186623		186623
4	BPAP NETWORK SIS 78862937	3,627	186623	3,447	186623
5	BPAP TRANS SIS 80289606	1,831	186623	(10,000)	186623
6	PAC PTP SIS 80381517		186623	(10,000)	186623
7					
8					
9					
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19					
20					
21	**Generation Studies**				
22	ALAMEDA SOLAR CENTER - GI 416		186623	(738)	186623
23	AMERICAN FALLS SOLAR # 431	10,601	186623	(20,127)	186623
24	AMERICAN FALLS SOLAR II # 433	6,725	186623	(13,508)	186623
25	BENSON CREEK WINDFARM GI 401	3,781	186623		186623
26	BLACK CREEK SOLAR #434	4,915	186623	(4,914)	186623
27	BOISE CITY SOLAR #432	13,775	186623	(50,000)	186623
28	BURNT RIVER #2 PROJECT 251		186623	96,144	186623
29	BURNT RIVER PROJECT 209		186623	91,424	186623
30	CLARK 2 SOLAR-20MW #438	85	186623	(1,000)	186623
31	CLARK 4 SOLAR-20MW #440	85	186623	(1,000)	186623
32	CLARK SOLAR 1 #437 7MW	857	186623	(10,000)	186623
33	CLARK SOLAR 3 #439 30MW	170	186623	(10,000)	186623
34	EIGHTMILE HYDRO GI 406	(159)	186623		186623
35	GRANDVIEW PV SOLAR FIVE GI 411	17,838	186623	(27,479)	186623
36	GRANDVIEW PV SOLAR FIVEA GI 418		186623	(1,300)	186623
37	GROVE SOLAR CENTER - GI 414	5,981	186623	(31,187)	186623
38	HEAD OF THE U HYDRO GI 409	1,605	186623	12,502	186623
39	HORSE CREEK SOLAR CENTER - GI 417		186623	(1,171)	186623
40	HYLINE SOLAR CENTER - GI 419	25,129	186623	(39,247)	186623

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Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
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20					
21	**Generation Studies**				
22	LITTLE WOOD RIVER RANCH II GI 410	1,741	186623	(5,136)	186623
23	MAGPIE WIND PROJECT 235		186623	104,869	186623
24	MOUTAIN HOME SOLAR-20MW #435		186623	(1,000)	186623
25	MT. HOME SOLAR #444		186623	(1,000)	186623
26	MURPHY FLAT POWER NORTH #426	8,486	186623	(13,423)	186623
27	MURPHY FLAT POWER SOUTH #427	3,540	186623	(1,000)	186623
28	MURPHY FLAT WIND FARM	244	186623	35,176	186623
29	OPEN RANGE SOLAR CENTER - GI 413	21,796	186623	(31,965)	186623
30	ORCHARD RANCH SOLAR-20MW #441		186623	(1,000)	186623
31	POCATELLO SOLAR-20MW #436		186623	(1,000)	186623
32	RAILROAD SOLAR CENTER - GI 423	12,652	186623	(37,842)	186623
33	RAILROAD SOLAR CENTER - GI 424	16,818	186623	(35,858)	186623
34	SAGEBRUSH SOLAR CENTER - GI 415		186623	153	186623
35	SALMON RIVER CANAL 550KW	1,534	186623	(1,000)	186623
36	SIMCO SOLAR #442		186623	(1,000)	186623
37	SIMCOE SOLAR CENTER #428	5,489	186623	(13,426)	186623
38	TILLI SOLAR #443		186623	(1,000)	186623
39	TURNER SOLAR CENTER - GI 420	2,707	186623	(1,707)	186623
40	VALE AIR SOLAR CENTER - GI 412	20,012	186623	(39,111)	186623

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
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6					
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17					
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19					
20					
21	**Generation Studies**				
22	WRIGHT PLACE SOLAR #445		186623	(1,000)	186623
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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	04/15/2015	End of 2014/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter /Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Asset Retirement Obligations (182341)	16,765,815	416,799	230	148,979	17,033,635
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	ASC 815 Mark to Market - ST (182330)	1,628,450	9,198,642	244	6,866,388	3,960,704
5						
6	FAS 109 Unfunded (182322)	710,482,403	91,705,942	282		802,188,345
7	Accum Deferred Income Noncurrent					
8						
9	PCA Deferral Idaho - IPUC Order #33049	63,093,814	55,993,923	Various	73,675,167	45,412,570
10	(Amort period 06/15 thru 05/16) (182323)					
11						
12	PCA Prior Year Deferral Idaho - IPUC Order #33049	30,418,393	58,426,586	various	76,309,131	12,535,848
13	(Amort period 06/14 thru 05/15) (182324)					
14						
15	Fixed Cost Adjuustment (FCA) (182302)	15,431,297	17,444,594	440/421	16,063,980	16,811,911
16	IPUC Order #33047 (Amort period 06/15 thru 05/1					
17						
18	Prior Year FCA IPUC Order #33047 (182309)	4,094,478	14,912,443	440/442	12,081,243	6,925,678
19	(Amort period 6/14 thru 5/15)					
20						
21	AOCI Impact of Unfunded Post Retirement Liability	(4,646,030)	5,732,807	228	182,989	903,788
22	IPUC Order #30256 (182306)					
23						
24	Oregon Pension Expense Capitalized (182339)	2,524,479	342,884	401/4073	116,997	2,750,366
25	OPUC Order #10-064 (Amort period thru 2052)					
26						
27	Deferred Pension Expense Net of Contributions	27,062,657	22,613,747	421/228	29,598,897	20,077,507
28	IPUC Order #30333 (182321)					
29						
30	AOCI Impact of Unfunded Pension Liability	121,228,583	146,725,287	228	4,309,107	263,644,763
31	IPUC Order #30256 (182320)					
32						
33	PCA Unbilled Forecast IPUC Order #53049 (182325)	(6,092,288)	38,352,606	401	33,316,131	-1,055,813
34						
35	PCAM Oregon 2008 (182346)	7,538,300	181,051	557/421	2,184,844	5,534,507
36	OPUC Order #08-238 & UE277 (Amort 1/14 - 7/17)					
37						
38	PCAM Interest Reserve 2008 (182329)	(793,327)	224,898	421		-568,429
39	OPUC Order #08-238 & UE 277 (Amort 1/14 - 7/17)					
40						
41	Excess Power Cost Deferral 2007 (182358)	26,915	69	401/421	26,984	
42	IPUC Order #09-189 (amort period 1/11 - 1/14)					
43						

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Idaho Boardman Decomissioning #32549 (182493)	749,740	6,380,447	various	5,912,680	1,217,507
2						
3						
4	2009 Reorg IPUC Order #30914 (182318)	230,655		401	230,655	
5	(Amort period 01/10 thru 12/14)					
6						
7	OATT Revenue Deferred Reserve (182336)	974,888		400	688,156	286,732
8	IPUC Order #30940 (amort period 06/12 thru 5/15)					
9						
10	Idaho Pension Cash (182327)	45,520,420	29,143,134	401/421	33,846,846	40,816,708
11	IPUC Order #32248					
12	(Amort period beginning 06/11 thru unknown)					
13						
14	2008 PCAM Unbilled Amort (182356)	(136,099)	1,793,467	557/421	1,815,670	-158,302
15	(Amort period 1/14 thru 7/17)					
16						
17	Lidar Surveys IPUC Order #32426 (182361)	348,837		402	43,604	305,233
18	(Amort period 01/12 thru 12/21)					
19						
20	Bennett Mtn Maintenance IPUC Order #32426	149,773		402	74,886	74,887
21	(Amort period 01/12 thru 12/15) (182379)					
22						
23	PCA Unbilled Amortization (182316)	(2,576,701)	48,408,091	400/401	48,212,040	-2,380,650
24	(Amort period 06/14 thru 05/15)					
25						
26	Idaho Boardman ARO Order #32549 (182393)	1,204,047		403/411	942,707	261,340
27	(Amort period thru 2020)					
28						
29	Langley Revenue Accrual Order #12-226 (182398)	872,084	69,873			941,957
30						
31	Minor items (32)	273,536	393,241	various	363,845	302,932
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	**TOTAL :**	1,036,375,119	548,460,531		347,011,926	1,237,823,724

Schedule Page: 232 Line No.: 9 Column: d

Contra accounts include 557, 421, 254, 440.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Prepaid ROW (186160)	659,834	12,898	401	246,788	425,944
2	Rents/Easements Long Term					
3						
4	Long-Term Portfolio (186255)	54,483	5,050,228	165	3,313,563	1,791,148
5						
6	Advance Prepaid (186709)	1,306,535		151	64,925	1,241,610
7	Coal Royalties					
8						
9	Security plan (186720)	18,115,431	8,160,417	426	6,216,769	20,059,079
10	Net Insurance Asset					
11						
12	American Falls Bond Ref(186722)	162,500		401	14,552	147,948
13	(Amort 04/00 - 02/25)					
14						
15	Prepaid Credit Facility(186025)	907,071		431	237,675	669,396
16	(amort period 10/12 thru 10/17)					
17						
18	Company Owned (186726)	3,921,641	1,063,448	426	1,150,865	3,834,224
19	Life Insurance					
20						
21	American Falls Water Rights	11,548,930		401	1,042,009	10,506,921
22	(amort 01/06 - 02/25) (186727)					
23						
24	Milner Bond Guarantee (186734)	4,254,545		253	1,063,636	3,190,909
25	(Amort 02/07 - 2/17)					
26						
27	American Falls - Bond refinance	535,991		401	48,000	487,991
28	(Amort through 02/25)(186770)					
29						
30	Shelf Registration (186732)	160,469	22	186	22	160,469
31						
32	Prepaid Exp (186052)	837,710	1,802,964	various	981,269	1,659,405
33	Contract I.T. Long Term					
34						
35	Long Term (186121)	1,186,330	6,639	228/401	62,220	1,130,749
36	Workers Compensation					
37						
38	Power Plant- Bridger (186780)		680,403	401	425,610	254,793
39						
40	Transmission & Generation	79,544	3,362,877	various	3,442,421	
41	Studies (186623)					
42						
43	Prepaid Coal LT (186797)	1,458,328		151/401	1,458,328	
44						
45	Minor Items (2)	19,424	48,977	Various	64,274	4,127
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,208,766				45,564,713

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5	Other Electric (See footnote)	118,958,964	97,597,101
6			
7	Other (See footnote)	106,991,643	169,747,033
8	TOTAL Electric (Enter Total of lines 2 thru 7)	225,950,607	267,344,134
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	20,824,214	21,759,450
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	246,774,821	289,103,584

Notes

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	Beginning Balance	Ending Balance
Federal NOL-Operating	28,544,014	0
Prov for Rate Refund-HC Relicensing (AFUDC)	23,062,458	28,529,481
Regulatory Asset-Non Current	23,538,502	18,067,486
Deferred Idaho ITC	15,346,759	17,378,549
VEBA-Post Retirement Benefits	9,962,466	10,617,384
Incentive Deferral-Profit Sharing-Not in Rates	0	5,085,262
Stock Based Compensation-FAS123R	3,532,282	3,782,196
Revenue Sharing	2,972,019	3,127,266
Pension Expense-Oregon	2,204,483	2,488,771
Rate Case Disallowance	2,389,579	2,273,741
Regulatory Liability-Current	1,826,860	1,918,442
Construction Advances	2,059,244	1,016,324
Valmy Union Pacific Contract	1,083,462	919,072
Asset Retirement Obligation (ARO)	425,053	865,690
M & E Reserve	0	592,049
Postretirement Benefits-SFAS112	579,781	568,869
Bridger Revenue Deferral	191,185	316,603
Executive Deferred Compensation	450,715	54,988
Deferred GBC Federal	31,500	31,500
CSPP Co-Generator Overpayment	470,282	0
Oregon NOL-Operating	247,299	0
Provision for Rate Refunds	155,600	0
Montana NOL-Operating	101,480	0
Boardman Decommission	(298,653)	0
Non-VEBA Pension and Benefits	82,596	(36,572)
Total Other Electric	118,958,964	97,597,101

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Pension-FAS 158	47,394,315	103,071,920
Regulatory Asset-FASB 109	50,788,061	50,814,726
Minimum Pension Liability	10,625,633	15,507,051
Postretirement Plan-FAS 158	(1,816,365)	353,336
Total Other	106,991,643	169,747,033

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Senior Management Security Plan	19,664,453	21,402,608
Micron CIAC-Depr Timing Diff	574,719	336,836
Federal NOL-Non Operating	534,662	0
Meridian Gold CIAC-Depr Timing Diff	42,118	20,006
Oregon NOL-Non Operating	6,409	0
Montana NOL-Non Operating	1,854	0
Total Non Electric	20,824,214	21,759,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock all of which is held by	50,000,000	2.50	
3	IdaCorp, Inc. and not traded			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	04/15/2015	End of 2014/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.00% Series due 2043	75,000,000	742,017
19			193,836 D
20			
21	6.00% Series due 2032	100,000,000	1,191,216
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	-585,759
25			746,961 D
26			
27	5.50% Series due 2034	50,000,000	524,419
28			383,322 D
29			
30	4.85% Series Due 2040	100,000,000	1,284,871
31			169,984 D
32			
33	TOTAL	1,627,045,000	26,907,384

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	6.30% Series due 2037	140,000,000	1,495,799
2			278,367 D
3			
4	6.25% Series due 2037	100,000,000	1,141,489
5			267,677 D
6			
7	Port of Morrow Variable due 2027	4,360,000	188,545
8	Humboldt Variable due 2024	49,800,000	1,697,856
9	Sweetwater Variable due 2026	116,300,000	3,026,122
10			
11	2.50% Series due 2023	75,000,000	648,267
12			371,854 D
13			
14	6.025 % Series Due 2018	120,000,000	1,630,120
15			
16	4.30% Series Due 2042	75,000,000	802,240
17			49,417 D
18	2.95% Series Due 2022	75,000,000	708,490
19			127,607 D
20	Subtotal Account 221	1,595,460,000	26,907,384
21			
22	Account 222 - Reaquired Bonds		
23			
24	Account 223: Advances for Associated Companies		
25			
26	Account 224:		
27	Bond Guarantee - American Falls	19,885,000	
28	Note Guarantee - Milner Dam	11,700,000	
29	Subtotal Account 224	31,585,000	
30			
31			
32			
33	TOTAL	1,627,045,000	26,907,384

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	6,150,000	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	3,400,000	12
						13
						14
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	15
						16
						17
4/8/2013	4/1/2043	4/8/2013	4/1/2043	75,000,000	3,000,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	30
						31
						32
				1,618,535,909	80,561,920	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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.
6/22/07	6/15/2037	6/22/07	6/15/37	140,000,000	8,820,000	1
						2
						3
10/18/07	10/15/2037	10/18/07	10/15/37	100,000,000	6,250,000	4
						5
						6
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	17,720	7
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	8
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	9
						10
4/8/2013	4/1/2023	4/8/2013	4/1/2023	75,000,000	1,875,000	11
						12
						13
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	14
						15
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	16
						17
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	18
						19
				1,595,460,000	80,561,920	20
						21
						22
						23
						24
						25
						26
04/26/00	2/1/25			19,885,000		27
02/10/92				3,190,909		28
				23,075,909		29
						30
						31
						32
				1,618,535,909	80,561,920	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	189,386,993
2		
3		
4	Taxable Income Not Reported on Books	
5		-98,931,827
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		50,782,788
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		19,918,608
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		114,202,966
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	7,116,380
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	2,490,733
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4000-FEDERAL NOL	$ (113,211,345)
4003-CONSTRUCTION ADVANCES	(2,979,771)
4005-AVOIDED COST	6,508,216
4010-EMISSION ALLOWANCES (ACCT 283)	13,495
4013-CIAC - TAXABLE - ACCT 107	8,850,300
4021-ENGINEERING FEES - TAXABLE - ACCT 107	528,786
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	2,023,523
4506-MERIDIAN GOLD CIAC - DEPR TIMING DIFF - NON-OP	(56,560)
4507-MICRON CIAC - DEPR TIMING DIFF - NON-OP	(608,471)
Total	**$ (98,931,827)**

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Total Federal and State taxes deducted on books	$ 15,784,451
5001-BAD DEBT EXPENSE	(398,034)
5010-POSTEMPLOYMENT BENEFITS-SFAS112	(27,913)
5014-VACATION ACCRUAL TAX ADJ - ACCT 242	586,964
5017-INJURIES & DAMAGES	379,858
5019-DEFERRED DIRECTORS FEES	(343,330)
5022-263A CAPITALIZED OVERHEADS	(25,000,000)
5023-PENSION EXPENSE (ACCT 283)	3,846,847
5024-NON-DEDUCTIBLE MEALS	500,000
5025-MILNER FALLING WATER	(48,550)
5028-OREGON OPERATING PROPERTY TAX ADJ	(9,810)
5033-NON-VEBA PENSION & BENEFITS	(304,817)
5035-PCA EXPENSE DEFERRAL	30,331,264
5043-AMERICAN FALLS - FALLING WATER CONTRACT	219,181
5046-EXECUTIVE DEFERRED COMP - ST	(984,570)
5047-EXECUTIVE DEFERRED COMP - LT	(27,649)
5048-BONUS DEFERRAL-OPERATING (DT 283) (Old Event)	(13,834)
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	8,189,137
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES (DT 190)	13,007,448
5052-AMORTIZATION OF ACCOUNT 181	272,059
5053-STOCK BASED COMPENSATION - FAS 123R	659,039
5055-OPUC GRID WEST LOANS	14,191
5057-INTERVENER FUNDING ORDERS	(98,495)
5058-FIXED COST ADJUSTMENT	(4,211,813)
5060-OREGON - PCAM	1,776,896
5061-PENSION EXPENSE - OREGON	727,172
5062-2011 LIDAR SURVEYS DEFERRAL	43,605
5063-BENNETT MTN MAINT DEFERRAL	74,886
5064-BRIDGER REVENUE DEFERRAL	320,803
5065-VALMY UNION PACIFIC CONTRACT	(420,488)
5066-BOARDMAN DECOMMISSION (DT 190)	763,915
5066-BOARDMAN DECOMMISSION (DT 283)	(1,238,525)
5067-ASSET RETIREMENT OBLIGATION (ARO)	804,745
5068-CSPP CO-GENERATOR OVERPAYMENT	(1,202,920)
5069-M & E RESERVE	1,514,386
5501-SMSP - INSURANCE COSTS	(177,316)
5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST	(19,873)
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	1,171,441

5505-SMSP - NET		4,445,979
5510-FINES & PENALTIES - OPERATING.		36,000
5516-NON-DEDUCTIBLE POLITICAL EXP - O&M ACCTS		100,000
5517-SMSP - UNREALIZED GAIN/LOSS FOR TAX		49,886
5531-RATE CASE DISALLOWANCES		(296,299)
5532-DELIVERY ACCRUALS		(13,129)
Total	**$**	**50,782,788**

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7009-PROVISION FOR RATE REFUNDS	$	398,006
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)		(13,983,946)
7011-OATT REVENUE DEFICIENCY		(688,156)
7012-REVENUE SHARING		(397,102)
7013-LANGLEY REVENUE ACCRUAL		48,838
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		7,092,887
7502-ALLOWANCE FOR OFUDC		17,930,898
7503-ALLOWANCE FOR BFUDC		8,464,109
7509-SMSP - INSURANCE PROCEEDS		1,053,074
Total	**$**	**19,918,608**

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8001-VEBA - POST RETIREMENT BENEFITS	$	(1,731,048)
8009-DEPR TIMING DIFF - OPERATING - FEDERAL		12,993,378
8020-CONSERVATION EXPENSES		973,123
8025-MANUFACTURING DEDUCTION		5,296,634
8027-NEVADA OPERATING PROPERTY TAX ADJ		142,023
8034-REMOVAL COSTS		10,445,838
8038-OREGON EXCESS POWER COSTS		(47,212)
8041-AMERICAN FALLS REFINANCE - OLD COSTS		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT		(1,060,585)
8057-REORGANIZATION COSTS		(230,656)
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107		500,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107		2,800,000
8073-REPAIRS DEDUCTION		75,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES		(605,997)
8501-COLI - INSURANCE COSTS		112,012
8504-OREGON NON-OP PROPERTY TAX ADJUSTMENT		55
8703-IPCO - 162 (M) $1m THRESHOLD		(207,282)
8901-REGULATORY ASSET - CURRENT		(13,994,159)
8901-REGULATORY ASSET - NON CURRENT		13,994,159
8902-REGULATORY LIABILITY - CURRENT		(234,256)
8902-REGULATORY LIABILITY - NON CURRENT		234,256
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		9,870,682
Total	**$**	**114,202,966**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	4,917,038		-10,331,231	12,446,979	
3	Social Security - (FOAB)	-13		14,043,578	14,044,743	
4	Unemployment			91,850	91,850	
5	Subtotal Federal	4,917,025		3,804,197	26,583,572	
6						
7	State of Idaho:					
8	Property	8,961,328		20,820,653	20,753,612	
9	Non-Operating	10,639		23,015	22,146	
10	Income	-139,933		6,921,987	9,695,941	
11	KWH	98,314		1,404,355	1,416,517	
12	Unemployment			651,894	651,894	
13	Regulatory Commission			2,688,423	2,688,423	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	8,930,348		32,510,477	35,228,683	
16						
17	State of Oregon					
18	Property		1,425,833	2,862,775	2,872,585	
19	Non-Operating Property		863	1,782	1,837	
20	Income	-6,462		-110,880	54,224	
21	Regulatory Commission			186,899	186,899	
22	Unemployment			51,486	51,486	
23	Franchise	213,724		800,080	807,855	
24	Subtotal Oregon	207,262	1,426,696	3,792,142	3,974,886	
25						
26	State of Montana:					
27	Property	144,976		321,531	305,096	
28	Subtotal Montana	144,976		321,531	305,096	
29						
30	State of Nevada:					
31	Property		360,323	1,173,729	1,315,753	
32	Subtotal Nevada		360,323	1,173,729	1,315,753	
33						
34	State of Wyoming					
35	Corporate License			4,744	4,744	
36	Property	775,189		1,604,927	1,577,652	
37	Subtotal Wyoming	775,189		1,609,671	1,582,396	
38	Other States Income	128,086		-140,147	5,336	
39	Payroll Tax Credit			-14,838,808		
40	Canada GST tax	1,524			5,060	-37,631
41	TOTAL	15,104,410	1,787,019	28,232,792	69,000,782	-37,631

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-17,861,172		-7,413,733			-2,917,498	2
-1,179		14,043,578				3
		91,850				4
-17,862,351		6,721,695			-2,917,498	5
						6
						7
9,028,370		20,819,856			797	8
11,508					23,015	9
-2,913,887		7,129,371			-207,384	10
86,152		1,404,355				11
		651,894				12
		2,688,423				13
		150				14
6,212,143		32,694,049			-183,572	15
						16
						17
	1,435,643	2,743,535			119,240	18
	918				1,782	19
-171,566		-87,450			-23,430	20
		186,899				21
		51,486				22
205,949		800,080				23
34,383	1,436,561	3,694,550			97,592	24
						25
						26
161,411		321,531				27
161,411		321,531				28
						29
						30
	502,346	1,173,729				31
	502,346	1,173,729				32
						33
						34
		4,744				35
802,464		1,604,927				36
802,464		1,609,671				37
-17,398		-133,337			-6,810	38
		-14,838,808				39
34,095						40
-10,635,253	1,938,907	31,243,080			-3,010,288	41

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

```
Account 409.2        $  (914,126)
Account 234.020       (2,003,372)
                     ------------
Total                $(2,917,498)
                     ============
```

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

```
Account 107        $   797
```

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

```
Account 408.2        $  23,015
```

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

```
Account 409.2        $  (23,447)
Account 234.020        (183,937)
                     -----------
Total                $ (207,384)
                     ===========
```

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

```
Account 107        $ 119,240
```

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

```
Account 408.2        $  1,782
```

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

```
Account 409.2        $ (14,076)
Account 234.020         (9,353)
                     ----------
Total                $ (23,430)
                     ==========
```

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

```
Account 409.2        $ (3,692)
Account 234.020        (3,118)
                     ---------
Total                $ (6,810)
                     =========
```

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

This amount is an offset to lines 3, 4, 11 & 22. Each month employer paid taxes flow into various 408.1 accounts. In that same month these amounts are offset with a different 408.1 account. These payroll taxes are then allocated back to the balance sheet and O & M accounts based on current month labor charges.

Schedule Page: 262 Line No.: 40 Column: f

Canada GST accrual is an adjustment because the offset account is not a 600 expense account.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	541,998				53,324	-54,475
4	7%						
5	10%	21,047,565				1,402,464	54,475
6		1,187,853				26,029	
7		56,343,874	411.4	3,044,087	411.4	1,520,729	
8	TOTAL	79,121,290		3,044,087		3,002,546	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	56,343,874	411.4	3,044,087	411.4	1,520,729	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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25							
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42							
43							
44							
45							
46							
47							
48							

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
434,199	10.16		3
			4
19,699,576	15.01		5
1,161,824	45.64		6
57,867,232	37.05		7
79,162,831			8
			9
			10
			11
57,867,232			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 3 Column: g

The adjusting entry is to tie the ending balance to the record detail and work papers.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Smart Grid (253200)	900,249	107/401	1,111,121	210,872	
2						
3	Point to Point Trans Study(253201)	899,702	2472	86,000	474,248	1,287,950
4						
5	FTV (253202)	3,266,666	400	400,000		2,866,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Sho Ban Trans ROW (253480)	217,500	107	15,000		202,500
9	(Amort Period Jan 2005-Dec 2027)					
10						
11	Milner Falling Water (253953)	715,735	186/401	1,165,699	1,117,149	667,185
12	Amort Period (Feb 1992 - Feb 2017)					
13						
14	Postretirement Benefits (253960)	1,483,006	401	27,913		1,455,093
15						
16	Directors Deferred Compensation	4,226,431	131	932,967	589,636	3,883,100
17	(253980-253999)					
18						
19	Operations Accrual (253550)	676,000	232/401	74,435	669,823	1,271,388
20	(amort period 1 year for dues)					
21						
22	Minor Items (1) 253042	1,432	various	44,478	44,806	1,760
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	12,386,721		3,857,613	3,106,534	11,635,642

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
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	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	436,837,016	30,575,458	16,294,782
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	436,837,016	30,575,458	16,294,782
6	Non-Operating Property			
7	Other - Regulatory Asset	706,253,450		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,143,090,466	30,575,458	16,294,782
10	Classification of TOTAL			
11	Federal Income Tax	980,163,502	30,306,822	16,294,782
12	State Income Tax	162,926,964	268,636	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
						451,117,692	2
							3
							4
						451,117,692	5
							6
		182	446,723	182	91,705,942	797,512,669	7
							8
			446,723		91,705,942	1,248,630,361	9
							10
			374,733		77,748,031	1,071,548,840	11
			71,990		13,957,911	177,081,521	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/15/2015	2014/Q4

FOOTNOTE DATA

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

Account	2014	Changes during Year				Adj Dr		Adj Cr		2014
	Beginning Balance	DR to 410.1	CR to 411.1	DR to 410.2	CR to 411.2	Acct. Cr	Amt	Acct. Dr.	Amt	End Bal
(a)	b	c	d	e	f	g	h	i	j	k
Depr Timing Diff-Oper	424,062,833	28,367,950	12,652,571							439,778,212
Intang-labor costs- Acct 107	14,385,202	2,997,709								17,382,911
CIAC-Taxable-Acct 107	(3,060,909)	430,646	3,380,470							(6,010,733)
Valmy Capitalized Items	198,266		76,500							121,766
Software - labor costs	1,567,943	(1,220,847)								347,096
Eng Fees in Acct 107	(316,318)		185,241							(501,560)
TOTAL	436,837,016	30,575,458	16,294,782	0	0		0		0	451,117,692

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	91,672,316	51,837,119	69,353,539
4				
5				
6				
7				
8	Other -- See Note	45,577,950		
9	TOTAL Electric (Total of lines 3 thru 8)	137,250,266	51,837,119	69,353,539
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	838,607		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	138,088,873	51,837,119	69,353,539
20	Classification of TOTAL			
21	Federal Income Tax	115,836,413	43,483,779	58,177,498
22	State Income Tax	22,252,460	8,353,340	11,176,041
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						74,155,896	3
							4
							5
							6
							7
					57,847,307	103,425,257	8
					57,847,307	177,581,153	9
							10
							11
							12
							13
							14
							15
							16
							17
80,909	68,392					851,124	18
80,909	68,392				57,847,307	178,432,277	19
							20
67,871	57,371				48,525,449	149,678,643	21
13,038	11,021				9,321,858	28,753,634	22
							23

NOTES (Continued)

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
Pension Expense	20,232,517	20,309,544	21,607,803							18,934,259
PCA Expense	33,169,456	6,656,883	18,514,891							21,311,448
Conservation Exp	1,409,026	3,426,730	3,046,288							1,789,468
Fixed Cost Adj	7,633,602	2,203,129	556,520							9,280,211
Reg Asset-Current	23,538,502	15,615,540	21,086,556							18,067,486
Oregon PCAM	2,636,947	0	694,677							1,942,270
Reg Liab-Non Current	1,826,860	2,647,701	2,556,119							1,918,442
Boardman Decommission	0	537,210	53,009							484,201
Oregon Excess Power Costs	(43,430)	6,432	24,889							(61,888)
OATT Revenue Deficiency	381,132		269,035							112,098
Renewable Energy Cert-sales	217,848	345,165	791,096							(228,084)
Langley Revenue Accr	331,688	19,093								350,781
Reorganization Costs	90,175	0	90,175							(0)
2011 LIDAR Surveys Def	136,378	0	17,047							119,331
Bennett Mtn Maint Def	58,554		29,277							29,277
Intervenor Funding Orders	82,837	38,507								121,344
OPUC Grid West Loans	6,472	0	5,548							925
Emission Allowances	(751)	9,749	5,276							3,722
Bonus Deferral	(10,970)	10,970								0
Delivery Accruals	(24,528)	10,465	5,332							(19,395)
TOTAL	91,672,316	51,837,119	69,353,539	0	0		0		0	74,155,896

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
Pension-FAS 158	47,394,315							190	55,677,606	103,071,921
Postretirement Plan-FAS 158	(1,816,365)							190	2,169,701	353,336
TOTAL	45,577,950	0	0	0	0				57,847307	103,425,257

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
EDC-Unrealized G/L from Rabbi Trust	535,261			15,954	8,185					543,030
SMSP-Unrealized G/L from Rabbi Trust	(22,448)			40,704	60,207					(41,951)
Royalty Income	325,457			24,230						349,687
Oregon Non-Op Prop Tax Adj	337			21	0					358
TOTAL	838,607	0	0	80,909	68,392		0		0	851,124

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - (254001)	1,384,229	175	7,425,080	7,857,878	1,817,027
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	288,132	175	977,925	753,115	63,322
5	IPUC Order # 28661					
6						
7	Unfunded Accum Def Income Tax (254966)	50,788,060	various	825,696	852,362	50,814,726
8						
9	Idaho DSM Rider (254201)	6,685,745	various	51,643,514	44,175,538	-782,231
10	Order #29026					
11						
12	Oregon DSM Rider - (254202)	(3,694,183)	various	1,925,980	1,712,627	-3,907,536
13	Advise #05-03					
14						
15	Oregon Solar Pilot - (254005)	1,787,012	various	66,751	680,603	2,400,864
16	Order #10-198					
17						
18	Green Tags Oregon (254415)	22,807	1823	23,584	133,608	132,831
19	Order #11-086					
20						
21	Regulatory Unfunded Accum Def Income Tax (254419)	4,228,953			446,724	4,675,677
22						
23	Revenue Sharing (254101)	7,602,043	182	7,624,233	8,021,335	7,999,145
24	IPUC Order #32558					
25						
26	BPA Credit Residential Idaho (254401)	624,555	131/400	2,457,934	2,477,282	643,903
27	Advice # 11-03 (ID) #11-15 (OR)					
28						
29	WAQC Carryover (254901)	90,075	various	90,075	112,536	112,536
30	IPUC Order #29505					
31						
32	Bridger Depreciation #12-296 -(254800)	489,027	various		320,803	809,830
33						
34	Minor Items (7)	80,545	various	575,835	558,465	63,175
35						
36						
37						
38						
39						
40						
41	TOTAL	70,377,000		73,636,607	68,102,876	64,843,269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	500,194,726	513,914,273
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	453,982,593	436,445,539
5	Large (or Ind.) (See Instr. 4)	182,675,224	165,918,266
6	(444) Public Street and Highway Lighting	4,133,623	3,828,398
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,140,986,166	1,120,106,476
11	(447) Sales for Resale	77,164,887	54,472,513
12	TOTAL Sales of Electricity	1,218,151,053	1,174,578,989
13	(Less) (449.1) Provision for Rate Refunds	18,348,408	18,735,088
14	TOTAL Revenues Net of Prov. for Refunds	1,199,802,645	1,155,843,901
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,780,239	3,565,357
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,695,291	24,427,455
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	27,734,886	36,377,773
22	(456.1) Revenues from Transmission of Electricity of Others	22,627,916	21,936,382
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	77,838,332	86,306,967
27	TOTAL Electric Operating Revenues	1,277,640,977	1,242,150,868

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
4,965,076	5,365,313	425,036	418,892	2
				3
5,877,580	6,040,697	84,425	83,439	4
3,217,070	3,181,866	116	117	5
32,641	31,478	2,380	2,205	6
				7
				8
				9
14,092,367	14,619,354	511,957	504,653	10
2,220,419	1,683,327			11
16,312,786	16,302,681	511,957	504,653	12
				13
16,312,786	16,302,681	511,957	504,653	14

Line 12, column (b) includes $ -6,191,476 of unbilled revenues.

Line 12, column (d) includes -75,221 MWH relating to unbilled revenues

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

This amount consists of:

Service Establishment/Connection Charges (Includes late and after hour charges)	$2,953,981
Misc. Under $250,000	826,258
	3,780,239

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

This amount consists of:

DSM Activity	$27,153,830
Stand-by-Service	321,995
Misc. Under $250,000	259,061
	27,734,886

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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27					
28					
29					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	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	04/15/2015	End of 2014/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,002,678	490,769,694	423,570	11,811	0.0981
3	03 - Residential Master Meter	4,234	396,120	22	192,455	0.0936
4	05 - Residential - TOD	24,949	2,355,949	1,444	17,278	0.0944
5	15 - Dusk to dawn lighting	2,670	651,491			0.2440
6	Unbilled Revenues	-69,455	-5,963,733			0.0859
7	Other Revenues		11,985,205			
8	Total 440	4,965,076	500,194,726	425,036	11,682	0.1007
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	151,333	18,212,254	30,433	4,973	0.1203
12	09P - General service	475,373	30,601,202	208	2,285,447	0.0644
13	09S - General service	3,282,762	240,216,057	33,227	98,798	0.0732
14	09T - General service	6,268	449,941	4	1,567,000	0.0718
15	15 - Dusk to Dawn Light	4,144	742,891			0.1793
16	19P - Uniform rate contracts	2,236,085	129,042,450	109	20,514,541	0.0577
17	19S - Uniform rate contracts	6,279	403,268	1	6,279,000	0.0642
18	19T - Uniform rate contracts	120,445	7,091,329	3	40,148,333	0.0589
19	24S - Irrigation Pumping	1,966,297	155,477,335	19,692	99,853	0.0791
20	40 - General service	10,526	907,059	861	12,225	0.0862
21	Special Contracts	841,166	42,295,181	3	280,388,667	0.0503
22	Commercial & Industrial Unbill	-6,028	-261,363			0.0434
23	Other Revenues		11,480,213			
24	Total 442	9,094,650	636,657,817	84,541	107,577	0.0700
25						
26	444 - Public Street Lighting:					
27	40 - General service	1,120	96,802	450	2,489	0.0864
28	41 - Street lighting	28,403	3,753,574	1,450	19,588	0.1322
29	42 - Traffic control lighting	2,856	179,973	480	5,950	0.0630
30	Unbilled	262	33,620			0.1283
31	Other Revenues		69,654			
32	Total 444	32,641	4,133,623	2,380	13,715	0.1266
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,167,588	1,147,177,642	511,957	27,673	0.0810
42	Total Unbilled Rev.(See Instr. 6)	-75,221	-6,191,476	0	0	0.0823
43	TOTAL	14,092,367	1,140,986,166	511,957	27,526	0.0810

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
2	Avista Corp.	SF	WSPP	n/a	n/a	n/a
3	Avista Corp.	OS	WSPP	n/a	n/a	n/a
4	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
5	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
6	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
7	BP Energy Company	SF	WSPP	n/a	n/a	n/a
8	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
9	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
10	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
11	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
12	Chelan County PUD	SF	WSPP	n/a	n/a	n/a
13	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
14	Citigroup Energy Inc.	OS	-	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	04/15/2015	End of 2014/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	City of Glendale	SF	WSPP	n/a	n/a	n/a
2	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
3	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
4	EDF Trading North America, LLC	OS	WSPP	n/a	n/a	n/a
5	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
6	Exelon Generation Company. LLC	SF	WSPP	n/a	n/a	n/a
7	Grant County Public Utility District #2	SF	WSPP	n/a	n/a	n/a
8	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
9	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
10	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
11	J. Aron & Company	SF	WSPP	n/a	n/a	n/a
12	Jeffries Bache	OS	-	n/a	n/a	n/a
13	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
14	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
2	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
3	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
4	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
5	Nevada Power Company, dba NVEnergy	SF	WSPP	n/a	n/a	n/a
6	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
7	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
8	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
9	PacifiCorp Inc.	OS	T-7	n/a	n/a	n/a
10	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
11	Platte River Power Authority	SF	WSPP	n/a	n/a	n/a
12	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
13	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
14	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

SALES FOR RESALE (Account 447)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

SALES FOR RESALE (Account 447)

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

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Southern Cal Edison	OS	WSPP	n/a	n/a	n/a
2	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
3	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
4	The Energy Authority, Inc.	OS	WSPP	n/a	n/a	n/a
5	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
6	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
8	Tucson Electric Power Company	SF	WSPP	n/a	n/a	n/a
9	Prior Year Adjustments	AD	-	n/a	n/a	n/a
10	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
11	Oatt Rate Refund	AD	-	n/a	n/a	n/a
12	Transmission Penalty Distribution	AD	-	n/a	n/a	n/a
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	04/15/2015	End of 2014/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.
6,120		152,680		152,680	1
335,232		13,140,061		13,140,061	2
87		2,175		2,175	3
840		37,486		37,486	4
			19	19	5
164,019		5,521,287		5,521,287	6
2,800		72,661		72,661	7
			110,968	110,968	8
24		624		624	9
		-139,784		-139,784	10
14,283		371,629		371,629	11
245					12
56		2,450		2,450	13
		-204,360		-204,360	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
90,000		4,136,386		4,136,386	1
171		5,780		5,780	2
14,214		618,450		618,450	3
		310,492		310,492	4
4,968		178,749		178,749	5
136,951		4,554,931		4,554,931	6
24,237		774,364		774,364	7
			52,800	52,800	8
8,682		291,316		291,316	9
					10
38		1,772		1,772	11
		-2,792,018		-2,792,018	12
199,100		7,874,193		7,874,193	13
		-1,266,434		-1,266,434	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
80,777		2,537,545		2,537,545	1
20		480		480	2
			448,193	448,193	3
			32,446	32,446	4
133,404		3,587,355		3,587,355	5
480		16,320		16,320	6
34,795		1,733,573		1,733,573	7
23,423		866,793		866,793	8
69		2,217		2,217	9
			38,873	38,873	10
17		935		935	11
67,585		2,494,290		2,494,290	12
785		17,831		17,831	13
48,415		1,369,537		1,369,537	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
			40,180	40,180	1
9,363		336,618		336,618	2
100		3,200		3,200	3
12,478		519,293		519,293	4
			15,593	15,593	5
49,536		1,452,174		1,452,174	6
215		6,450		6,450	7
17,638		622,449		622,449	8
			754,958	754,958	9
265,522		9,244,324		9,244,324	10
49		1,819		1,819	11
			3,715	3,715	12
800		24,550		24,550	13
430		13,280		13,280	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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.
			735	735	1
			10,950	10,950	2
20,513		514,208		514,208	3
			3,373	3,373	4
427,455		15,851,245		15,851,245	5
			72,656	72,656	6
23,727		680,341		680,341	7
754		26,035		26,035	8
2					9
			10,822	10,822	10
			-2,523	-2,523	11
			3,377	3,377	12
					13
					14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

Schedule Page: 310 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 5 Column: b
Financial Transmission Losses
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.: 10 Column: b
ISDA Master Agreement with Cargill Power Markets LLC, dated June 13, 2011
Schedule Page: 310 Line No.: 14 Column: b
ISDA Master Agreement with Citigroup Energy, Inc., dated March 7, 2011
Schedule Page: 310.1 Line No.: 4 Column: b
ISDA Master Agreement with EDF Trading North America, LLC, dated October 25, 2012.
Schedule Page: 310.1 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 10 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 12 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4, 2008
Schedule Page: 310.1 Line No.: 14 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011
Schedule Page: 310.2 Line No.: 2 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 6 Column: b
Unit Contingent Sales
Schedule Page: 310.2 Line No.: 9 Column: b
Spinning or Operating Reserves
Schedule Page: 310.2 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 11 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 2 Column: b

Financial Transmission Losses

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

Financial Transmission Losses

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

Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	1,376,709	1,524,957
5	(501) Fuel	156,172,175	160,276,741
6	(502) Steam Expenses	8,741,266	8,840,885
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,599,507	1,741,112
10	(506) Miscellaneous Steam Power Expenses	9,598,723	9,473,766
11	(507) Rents	530,520	348,322
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	178,018,900	182,205,783
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	277,886	101,619
16	(511) Maintenance of Structures	708,308	637,844
17	(512) Maintenance of Boiler Plant	10,923,064	12,461,886
18	(513) Maintenance of Electric Plant	6,044,954	5,398,984
19	(514) Maintenance of Miscellaneous Steam Plant	5,806,415	4,541,443
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,760,627	23,141,776
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	201,779,527	205,347,559
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	5,700,460	6,034,727
45	(536) Water for Power	7,316,134	5,679,423
46	(537) Hydraulic Expenses	14,097,825	13,572,536
47	(538) Electric Expenses	1,530,453	1,432,669
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,732,591	4,855,798
49	(540) Rents	259,705	141,597
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	34,637,168	31,716,750
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	122,182	83,805
54	(542) Maintenance of Structures	1,387,369	1,427,309
55	(543) Maintenance of Reservoirs, Dams, and Waterways	366,307	1,148,299
56	(544) Maintenance of Electric Plant	2,279,584	2,617,210
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,554,638	3,005,680
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,710,080	8,282,303
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,347,248	39,999,053

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	813,875	1,360,914
63	(547) Fuel	45,068,831	54,204,949
64	(548) Generation Expenses	3,596,219	3,427,130
65	(549) Miscellaneous Other Power Generation Expenses	905,574	585,699
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	50,384,499	59,578,692
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		99
70	(552) Maintenance of Structures	378,067	301,287
71	(553) Maintenance of Generating and Electric Plant	86,516	131,162
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,391,428	1,233,983
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,856,011	1,666,531
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	52,240,510	61,245,223
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	237,121,899	214,941,823
77	(556) System Control and Load Dispatching	-1,242	1,403,451
78	(557) Other Expenses	25,139,587	-34,629,989
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	262,260,244	181,715,285
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	557,627,529	488,307,120
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,019,284	3,560,221
84			
85	(561.1) Load Dispatch-Reliability	55,425	39,635
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,673,701	1,702,334
87	(561.3) Load Dispatch-Transmission Service and Scheduling	926,555	1,036,729
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	38,422	94,561
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,458,270	2,403,457
94	(563) Overhead Lines Expenses	669,240	732,402
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,081,299	5,637,278
97	(566) Miscellaneous Transmission Expenses	18,274	49,579
98	(567) Rents	3,284,850	2,917,528
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,225,320	18,173,724
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	169,505	323,417
102	(569) Maintenance of Structures	26,645	7,617
103	(569.1) Maintenance of Computer Hardware	9,454	7,491
104	(569.2) Maintenance of Computer Software	960,142	734,188
105	(569.3) Maintenance of Communication Equipment	42,031	4,564
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,702,550	3,610,183
108	(571) Maintenance of Overhead Lines	3,198,420	3,588,427
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,593	607
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,110,340	8,276,494
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,335,660	26,450,218

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,028,859	4,160,840
135	(581) Load Dispatching	3,643,133	3,529,347
136	(582) Station Expenses	1,180,321	1,375,049
137	(583) Overhead Line Expenses	3,138,798	3,111,427
138	(584) Underground Line Expenses	2,525,008	2,402,213
139	(585) Street Lighting and Signal System Expenses	76,902	74,337
140	(586) Meter Expenses	4,424,696	4,421,678
141	(587) Customer Installations Expenses	694,859	673,959
142	(588) Miscellaneous Expenses	5,788,865	5,754,224
143	(589) Rents	466,127	366,175
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,967,568	25,869,249
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	16,451	168,884
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,950,824	3,816,291
149	(593) Maintenance of Overhead Lines	13,906,165	14,492,291
150	(594) Maintenance of Underground Lines	630,375	645,600
151	(595) Maintenance of Line Transformers	148,125	286,874
152	(596) Maintenance of Street Lighting and Signal Systems	531,740	536,040
153	(597) Maintenance of Meters	735,448	750,543
154	(598) Maintenance of Miscellaneous Distribution Plant	418,635	412,978
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,337,763	21,109,501
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,305,331	46,978,750
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	503,846	491,363
160	(902) Meter Reading Expenses	1,698,642	1,484,232
161	(903) Customer Records and Collection Expenses	16,630,398	14,060,136
162	(904) Uncollectible Accounts	6,715,796	5,805,414
163	(905) Miscellaneous Customer Accounts Expenses	95	271
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	25,548,777	21,841,416

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	593,673	531,496
168	(908) Customer Assistance Expenses	34,149,782	42,690,734
169	(909) Informational and Instructional Expenses	374,524	264,701
170	(910) Miscellaneous Customer Service and Informational Expenses	696,365	574,875
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	35,814,344	44,061,806
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	73,163,837	69,143,869
182	(921) Office Supplies and Expenses	17,437,094	17,610,990
183	(Less) (922) Administrative Expenses Transferred-Credit	27,257,584	26,882,864
184	(923) Outside Services Employed	4,705,146	5,271,865
185	(924) Property Insurance	3,461,411	3,673,489
186	(925) Injuries and Damages	6,125,055	5,694,399
187	(926) Employee Pensions and Benefits	61,971,169	62,531,128
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,457,838	3,975,664
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	453,160	496,936
192	(930.2) Miscellaneous General Expenses	4,907,415	4,246,371
193	(931) Rents	176	6,536
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,424,717	145,768,383
195	Maintenance		
196	(935) Maintenance of General Plant	7,508,482	5,252,115
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	155,933,199	151,020,498
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	848,564,840	778,659,808

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	AgPower Jerome / Double A Digester	LU	-	N/A	N/A	N/A
2	Allan Ravenscroft/Malad River	LU	-	.488Mw		
3	Bannock County, Idaho	LU	-	N/A	N/A	N/A
4	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
5	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
6	Big Sky West Dairy Digester	LU	-	N/A	N/A	N/A
7	Big Wood Canal Company		-			
8	Black Canyon #3	LU	-	N/A	N/A	N/A
9	Jim Knight	LU	-	N/A	N/A	N/A
10	Sagebrush	LU	-	N/A	N/A	N/A
11	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
12	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
13	Burley Butte Wind Park	LU	-	N/A	N/A	N/A
14	Bypass Limited	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	Camp Reed Wind Park	LU	-	N/A	N/A	N/A
2	Cargill Inc./B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
3	Cassia Wind Farm	LU	-	N/A	N/A	N/A
4	City of Cove, Oregon / Mill Creek	LU	-	N/A	N/A	N/A
5	City of Hailey	LU	-	N/A	N/A	N/A
6	City of Pocatello	LU	-	N/A	N/A	N/A
7	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
8	Clifton E. Jenson/Birch Creek	LU	-	.05Mw		
9	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
10	Consolidated Hydro Inc. / Enel		-			
11	Barber Dam	LU	-	N/A	N/A	N/A
12	Dietrich Drop	LU	-	N/A	N/A	N/A
13	GeoBon #2	LU	-	N/A	N/A	N/A
14	Lowline #2	LU	-	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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1	Rock Creek #2	LU	-	N/A	N/A	N/A
2	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
3	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
4	Curry Cattle Company	LU	-	.084Mw		
5	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
6	David R Snedigar	LU	-	N/A	N/A	N/A
7	Desert Meadow Wind Farm	LU	-	N/A	N/A	N/A
8	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
9	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
10	Fisheries Development	OS	-	N/A	N/A	N/A
11	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
12	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
13	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
14	Hammett Hill Windfarm, LLC	LU	-	N/A	N/A	N/A
	Total					

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

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

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1	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
2	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
3	Lime Wind	LU	-	N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
6	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
7	Mainline Windfarm	LU	-	N/A	N/A	N/A
8	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
9	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
10	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
11	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
12	New Energy One / Rock Creek Dairy	LU	-	N/A	N/A	N/A
13	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
14	Owyhee Irrigation District					
	Total					

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1	Mitchell Butte	LU	-	N/A	N/A	N/A
2	Owyhee Dam	LU	-	N/A	N/A	N/A
3	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
4	Pigeon Cove Power	LU	-	1.389		
5	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
6	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
7	Pristine Springs Inc. #3	LU	-	N/A	N/A	N/A
8	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
9	Richard Kaster					
10	Box Canyon	LU	-	N/A	N/A	N/A
11	Briggs Creek	LU	-	N/A	N/A	N/A
12	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
13	Riverside Investments					
14	Arena Drop	LU	-	N/A	N/A	N/A
	Total					

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1	Fargo Drop	LU	-	N/A	N/A	N/A
2	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
3	Rockland Wind Project	LU	-	N/A	N/A	N/A
4	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
5	Ryegrass Windfarm	LU	-	N/A	N/A	N/A
6	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
7	SE Hazelton A LP	LU	-	N/A	N/A	N/A
8	Shorock Hydro Inc.					
9	Shoshone CSPP	LU	-	N/A	N/A	N/A
10	Shoshone #2	LU	-	N/A	N/A	N/A
11	Snake River Pottery	LU	-	N/A	N/A	N/A
12	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
13	Tamarack Energy Partnership	LU	-	4.942Mw		
14	Tasco - Nampa	OS	-	N/A	N/A	N/A
	Total					

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

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1	Other Purchased Power					
2	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
3	Avista Corp.	OS	T-12	N/A	N/A	N/A
4	Avista Corp.	SF	WSPP	N/A	N/A	N/A
5	Avista Corp.	OS	WSPP	N/A	N/A	N/A
6	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
7	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
8	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
9	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
10	BP Energy Company	SF	WSPP	N/A	N/A	N/A
11	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
12	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
13	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
14	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Citigroup Energy Inc.	OS	-	N/A	N/A	N/A
2	City of Glendale	SF	WSPP	N/A	N/A	N/A
3	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
4	Constellation Energy Control and Dispa	OS	WSPP	N/A	N/A	N/A
5	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
6	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
7	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
8	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
9	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
10	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
11	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
12	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
13	Jefferies Bache	OS	-	N/A	N/A	N/A
14	Los Angeles Dept of Water & Power - En	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	04/15/2015	End of 2014/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	Municipal Energy Agency of Nebraska	SF	WSPP	N/A	N/A	N/A
2	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
3	Nevada Power Company, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
4	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
5	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
6	PacifiCorp Inc.	OS	T-13	N/A	N/A	N/A
7	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
8	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
9	Portland General Electric Company	OS	T-14	N/A	N/A	N/A
10	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
11	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
12	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
13	PPL EnergyPlus, LLC	OS	WSPP	N/A	N/A	N/A
14	Public Service Company of New Mexico	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Puget Sound Energy, Inc.	OS	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	Salt River Project	SF	WSPP	N/A	N/A	N/A
5	Seattle City Light	OS	WSPP	N/A	N/A	N/A
6	Seattle City Light	OS	WSPP	N/A	N/A	N/A
7	Seattle City Light	SF	WSPP	N/A	N/A	N/A
8	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
9	Sierra Pacific Power Co., dba NV Energ	OS	T-55	N/A	N/A	N/A
10	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
11	Tacoma Power	OS	WSPP	N/A	N/A	N/A
12	Tacoma Power	SF	WSPP	N/A	N/A	N/A
13	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
14	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
2	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
3	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
4	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
5	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
6	Net Metering Customers	OS	-	N/A	N/A	N/A
7	Oregon Solar Customers	OS	-	N/A	N/A	N/A
8	Prior Year Adjustments	AD	-	N/A	N/A	N/A
9	Prior Year Adjustments	OS	-	N/A	N/A	N/A
10	Power Exchanges		-			
11	Bonneville Power Administration	EX	-			
12	NorthWestern Energy	EX	-			
13	PacifiCorp Inc.	EX	-			
14	Powerex Corp.	EX	-			
	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	04/15/2015	End of 2014/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Co., dba NV Energ	EX	-			
2	Clatskanie PUD	EX	153			
3	Other Transactions					
4	Acctg Valuation of Clatskanie PUD					
5	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
6	Clark Canyon Damages	OS	-	N/A	N/A	N/A
7	PacifiCorp Loss Repayment	OS	-	N/A	N/A	N/A
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
27,305				2,267,324		2,267,324	1
1,604			155,672	62,590		218,262	2
4,816				208,408		208,408	3
44,719				2,688,291		2,688,291	4
13,455				1,094,933		1,094,933	5
8,762				517,645		517,645	6
							7
333				23,357		23,357	8
953				68,977		68,977	9
964				69,618		69,618	10
3,366				347,470		347,470	11
693				48,651		48,651	12
61,275				3,334,374		3,334,374	13
27,052				1,464,756		1,464,756	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
66,813				5,615,388		5,615,388	1
8,468				702,326		702,326	2
26,647				1,525,090		1,525,090	3
3,702				270,590		270,590	4
50				3,580		3,580	5
1,407				104,145		104,145	6
3,532				333,945		333,945	7
321			17,500	12,434		29,934	8
53,793				3,502,993		3,502,993	9
							10
10,349				538,180		538,180	11
15,142				839,625		839,625	12
3,064				234,774		234,774	13
7,654				419,399		419,399	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
6,828				358,045		358,045	1
4,755				334,097		334,097	2
10,437				704,700		704,700	3
638			26,796	25,316		52,112	4
521				15,563		15,563	5
1,346				93,905		93,905	6
62,680				4,069,461		4,069,461	7
139				7,438		7,438	8
3,265				253,809		253,809	9
1,152				35,623		35,623	10
24,775				1,389,340		1,389,340	11
18,259				1,123,012		1,123,012	12
34,007				1,843,655		1,843,655	13
60,610				3,942,261		3,942,261	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
22,826				1,613,586		1,613,586	1
97,693				4,616,740		4,616,740	2
1,615				135,121		135,121	3
44,794				3,107,261		3,107,261	4
19,321				1,071,969		1,071,969	5
41,453				2,475,077		2,475,077	6
59,691				4,617,988		4,617,988	7
74,878				3,744,319		3,744,319	8
1,130				80,206		80,206	9
4,192				296,037		296,037	10
626				35,417		35,417	11
3,494				306,397		306,397	12
5,900				482,669		482,669	13
2,906				269,371		269,371	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
7,567				487,034		487,034	1
1,273				98,057		98,057	2
5,817				426,161		426,161	3
6,002				391,208		391,208	4
2,071				143,368		143,368	5
5,806				278,193		278,193	6
59,185				3,844,357		3,844,357	7
2,196				149,801		149,801	8
54,155				3,646,985		3,646,985	9
59,061				3,202,889		3,202,889	10
460				30,610		30,610	11
13,390				1,020,631		1,020,631	12
38,403				2,096,620		2,096,620	13
							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
96				2,903		2,903	1
10,655				260,408		260,408	2
63,921				5,374,826		5,374,826	3
8,482			486,150	290,674		776,824	4
33,185				1,809,265		1,809,265	5
808				49,850		49,850	6
1,231				65,916		65,916	7
1,259				94,590		94,590	8
							9
2,049				136,478		136,478	10
3,668				251,069		251,069	11
4,916				285,491		285,491	12
							13
1,578				126,368		126,368	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,487				162,914		162,914	1
9,163			552,508	361,700		914,208	2
263,174				16,003,917		16,003,917	3
76,713				5,076,275		5,076,275	4
56,392				3,660,876		3,660,876	5
65,142				3,534,112		3,534,112	6
23,682				1,652,669		1,652,669	7
							8
1,427				128,652		128,652	9
2,113				151,502		151,502	10
334				22,835		22,835	11
29,140				2,108,441		2,108,441	12
28,870			1,576,498	1,309,257		2,885,755	13
84				2,162		2,162	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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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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				33		33	1
28,813				1,564,466		1,564,466	2
32,787				1,799,288		1,799,288	3
30,056				1,642,697		1,642,697	4
79,036				4,351,059		4,351,059	5
8,810				541,845		541,845	6
62,355				4,024,407		4,024,407	7
654				44,886		44,886	8
3,157				241,027		241,027	9
928				70,342		70,342	10
26,527				1,878,057		1,878,057	11
65,032				5,441,691		5,441,691	12
				-1,884,407		-1,884,407	13
-4,830							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
393				7,963		7,963	2
11				258		258	3
135,562				3,779,679		3,779,679	4
					249,576	249,576	5
75				3,225		3,225	6
					678,417	678,417	7
111				2,534		2,534	8
78,087				2,551,020		2,551,020	9
8,000				102,000		102,000	10
219				-595		-595	11
8,437				293,515		293,515	12
4				108		108	13
151,200				6,818,064		6,818,064	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	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.
					-104,044	-104,044	1
38				1,772		1,772	2
325				3,592		3,592	3
2				79		79	4
115,825				4,322,798		4,322,798	5
2,842				76,859		76,859	6
8,817				77,358		77,358	7
5				148		148	8
175				8,225		8,225	9
92,730				2,951,306		2,951,306	10
62,400				2,691,169		2,691,169	11
20,800				1,076,400		1,076,400	12
					1,520,390	1,520,390	13
252				8,403		8,403	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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		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)	
30				1,260		1,260	1
88,123				3,519,175		3,519,175	2
6,319				285,274		285,274	3
9				258		258	4
5,545				165,077		165,077	5
73				1,744		1,744	6
5,593				175,683		175,683	7
					180,673	180,673	8
10				354		354	9
10,507				366,566		366,566	10
125,810				4,137,949		4,137,949	11
206,278				6,532,457		6,532,457	12
75				3,375		3,375	13
2,875				135,335		135,335	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
15				446		446	1
15,227				419,651		419,651	2
6,497				220,226		220,226	3
110				5,250		5,250	4
6				150		150	5
400				12,396		12,396	6
12,977				416,270		416,270	7
7,243				216,694		216,694	8
41				952		952	9
1,397				16,955		16,955	10
2				69		69	11
400				18,025		18,025	12
547				20,704		20,704	13
25,626				470,756		470,756	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11,907				397,120		397,120	1
4,108				52,933		52,933	2
78,916				4,987,942		4,987,942	3
292,788				16,446,275		16,446,275	4
183,529				18,747,659		18,747,659	5
544				214		214	6
696				27,804		27,804	7
2							8
					-2,453	-2,453	9
							10
	69,122						11
	19,041	977					12
	163,705	137,305					13
	277						14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
		4,764					1
	72,658	68,175					2
							3
					-163,570	-163,570	4
				7,940,697		7,940,697	5
					-373,490	-373,490	6
81,625							7
							8
							9
							10
							11
							12
							13
							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

Schedule Page: 326 Line No.: 2 Column: e
Unavailable
Schedule Page: 326 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.1 Line No.: 8 Column: e
Unavailable
Schedule Page: 326.1 Line No.: 8 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.: 10 Column: b
Non Firm Purchases
Schedule Page: 326.3 Line No.: 1 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.5 Line No.: 4 Column: e
Unavailable
Schedule Page: 326.5 Line No.: 4 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 2 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 12 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.6 Line No.: 13 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Co. The actual demand is not used in determining the cost of energy.
Schedule Page: 326.6 Line No.: 13 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 13 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 14 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 1 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 11 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.7 Line No.: 13 Column: a
Prior Period Overpayment Recovery (JR Simplot)
Schedule Page: 326.7 Line No.: 14 Column: a
Difference between booked and scheduled energy
Schedule Page: 326.8 Line No.: 3 Column: b
Non Firm Purchases
Schedule Page: 326.8 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 326.8 Line No.: 7 Column: b
Financial Transmission losses
Schedule Page: 326.8 Line No.: 8 Column: b
Non Firm Purchases
Schedule Page: 326.8 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 1 Column: b

ISDA Naster Agreement with Citigroup Energy PLC dated March 7, 2011.

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

Non Firm Purchases

Schedule Page: 326.9 Line No.: 8 Column: b

Non Firm Purchases

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

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

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

Non Firm Purchases

Schedule Page: 326.10 Line No.: 6 Column: b

Non Firm Purchases

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

Financial Transmission Losses

Schedule Page: 326.10 Line No.: 9 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 13 Column: b

Non Firm Purchases

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

Non Firm Purchases

Schedule Page: 326.11 Line No.: 5 Column: b

Non Firm Purchases

Schedule Page: 326.11 Line No.: 6 Column: b

Non Firm Purchases

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

Non Firm Purchases

Schedule Page: 326.11 Line No.: 11 Column: b

Non Firm Purchases

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

Unavailable

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

Schedule 84 Net Metering

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

Schedule 88 Oregon Solar

Schedule Page: 326.12 Line No.: 9 Column: b

Financial Transmission Losses

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

Financial Transmission losses

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

Financial Transmission Losses

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

Financial Transmission losses

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

Financial Transmission Losses

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

Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
4	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	AD
5	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
6	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	AD
7	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Idaho Customers	AD
8	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
9	Shell Energy North America (US), L.P.	Seattle City Light	Bonneville Power Administration	OS
10	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
11	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
12	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
13	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	OS
14	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
15	Avista Corporation	NorthWestern/PacifiCorp East	Avista	NF
16	Avista Corporation			AD
17	Black Hills Power Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Black Hills Power Inc.			AD
19	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
21	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
22	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
23	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
24	Bonneville Power Administration			AD
25	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Cargill Power Markets LLC	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	Cargill Power Markets LLC	PacifiCorp East	Bonneville Power Administration	NF
28	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
29	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Cargill Power Markets LLC	PacifiCorp East	Sierra Pacific Power	NF
31	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	NF
32	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	SFP
33	Cargill Power Markets LLC	PacifiCorp West	Sierra Pacific Power	NF
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	04/15/2015	End of 2014/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Cargill Power Markets LLC	PacifiCorp West	Sierra Pacific Power	SFP
2	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	NF
3	Cargill Power Markets LLC	PacifiCorp West	NorthWestern/PacifiCorp East	NF
4	Cargill Power Markets LLC	PacifiCorp West	Bonneville Power Administration	NF
5	Cargill Power Markets LLC	PacifiCorp West	Sierra Pacific Power	NF
6	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Cargill Power Markets LLC	Bonneville Power Administration	PacifiCorp East	NF
8	Cargill Power Markets LLC	Bonneville Power Administration	Sierra Pacific Power	NF
9	Cargill Power Markets LLC	Avista	PacifiCorp East	NF
10	Cargill Power Markets LLC	Avista	PacifiCorp East	SFP
11	Cargill Power Markets LLC	Avista	Bonneville Power Administration	NF
12	Cargill Power Markets LLC	Avista	Sierra Pacific Power	NF
13	Cargill Power Markets LLC	Avista	Sierra Pacific Power	SFP
14	Cargill Power Markets LLC	Sierra Pacific Power	Bonneville Power Administration	NF
15	Cargill Power Markets LLC			AD
16	Constellation Energy			AD
17	Endure Energy			AD
18	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
19	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Iberdrola Renewables LLC	Idaho Power Company	PacifiCorp East	NF
23	Iberdrola Renewables LLC	Idaho Power Company	Sierra Pacific Power	NF
24	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	Iberdrola Renewables LLC	Bonneville Power Administration	PacifiCorp East	NF
26	Iberdrola Renewables LLC	Bonneville Power Administration	Sierra Pacific Power	NF
27	Iberdrola Renewables LLC	Avista	PacifiCorp East	NF
28	Iberdrola Renewables LLC	Avista	Sierra Pacific Power	NF
29	Iberdrola Renewables LLC	Sierra Pacific Power	Bonneville Power Administration	NF
30	Iberdrola Renewables LLC	Idaho Power Company	Bonneville Power Administration	NF
31	Iberdrola Renewables LLC			AD
32	MacQuarie Cook			AD
33	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
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	04/15/2015	End of 2014/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 Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
2	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
5	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
7	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
8	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
10	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
13	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
14	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
15	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
17	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
19	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
22	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
24	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
25	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
26	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
27	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp West	NF
29	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp West	Idaho Power Company	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp West	Bonneville Power Administration	NF
33	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
2	Morgan Stanley Capital Group Inc.	Idaho Power Company	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
5	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
7	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
8	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
10	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	NorthWestern/PacifiCorp East	NF
13	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
15	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Avista	NorthWestern/PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	Avista	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	SFP
20	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
22	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.			AD
26	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
27	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
28	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	SFP
29	Nevada Power Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Nevada Power Company	Bonneville Power Administration	Sierra Pacific Power	NF
31	Nevada Power Company	Avista	Sierra Pacific Power	NF
32	Nevada Power Company	Avista	Sierra Pacific Power	SFP
33	Nevada Power Company	Sierra Pacific Power	PacifiCorp East	NF
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	04/15/2015	End of 2014/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	Nevada Power Company	Sierra Pacific Power	Idaho Power Company	NF
2	Nevada Power Company	Sierra Pacific Power	Bonneville Power Administration	NF
3	Northwestern Energy			AD
4	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
5	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
6	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	LFP
7	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
8	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
9	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
10	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
11	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
12	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
13	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
14	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
15	PacifiCorp Inc.	PacifiCorp West	Bonneville Power Administration	NF
16	PacifiCorp Inc.	Idaho Power Company	Sierra Pacific Power	SFP
17	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
18	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
19	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
20	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	LFP
21	PacifiCorp Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
22	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	LFP
23	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	NF
24	PacifiCorp Inc.	Idaho Power Company	Bonneville Power Administration	NF
25	PacifiCorp Inc.	Idaho Power Company	Avista	NF
26	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
27	PacifiCorp Inc.	Avista	PacifiCorp East	NF
28	PacifiCorp Inc.	Avista	PacifiCorp West	NF
29	PacifiCorp Inc.	Avista	Bonneville Power Administration	NF
30	PacifiCorp Inc.			AD
31	Portland General Electric Company	PacifiCorp East	NorthWestern/PacifiCorp East	NF
32	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
33	Portland General Electric Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Portland General Electric Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
2	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
3	Portland General Electric Company	Idaho Power Company	PacifiCorp East	NF
4	Portland General Electric Company	Idaho Power Company	Sierra Pacific Power	NF
5	Portland General Electric Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Portland General Electric Company	Bonneville Power Administration	Sierra Pacific Power	NF
7	Portland General Electric Company	Sierra Pacific Power	Bonneville Power Administration	NF
8	Portland General Electric Company			AD
9	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
11	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
12	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
13	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
14	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
15	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
16	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
18	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
19	Powerex Corporation	NorthWestern/PacifiCorp East	Idaho Power Company	NF
20	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
21	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
23	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
24	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
25	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
26	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
27	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
28	Powerex Corporation	PacifiCorp West	PacifiCorp East	SFP
29	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
30	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
31	Powerex Corporation	NorthWestern/PacifiCorp East	NorthWestern/PacifiCorp East	NF
32	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
33	Powerex Corporation	NorthWestern/PacifiCorp East	Idaho Power Company	NF
34				
	TOTAL			

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Powerex Corporation			AD
2	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	PPL EnergyPlus, LLC	PacifiCorp East	Bonneville Power Administration	NF
4	PPL EnergyPlus, LLC	PacifiCorp East	Sierra Pacific Power	NF
5	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
7	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
8	PPL EnergyPlus, LLC			AD
9	Puget Sound Energy, Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
10	Puget Sound Energy, Inc.	PacifiCorp West	Bonneville Power Administration	NF
11	Puget Sound Energy, Inc.	PacifiCorp West	Avista	NF
12	Puget Sound Energy, Inc.	Avista	Bonneville Power Administration	NF
13	Puget Sound Energy, Inc.			AD
14	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
16	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
17	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
19	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
20	Rainbow Energy Marketing Corporation	PacifiCorp West	PacifiCorp East	NF
21	Rainbow Energy Marketing Corporation	Avista	PacifiCorp East	NF
22	Rainbow Energy Marketing Corporation	Avista	PacifiCorp East	SFP
23	Rainbow Energy Marketing Corporation			AD
24	Seattle City Light			AD
25	Sempra Energy			AD
26	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
27	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
28	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
29	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
30	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
31	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
32	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
33	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
34				
	TOTAL			

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	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
2	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	SFP
3	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
4	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	SFP
5	Shell Energy North America (US), L.P.	PacifiCorp West	Bonneville Power Administration	NF
6	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	SFP
7	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
10	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
11	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	NF
12	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
13	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	SFP
14	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
15	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	SFP
16	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
17	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
18	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	SFP
19	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	LFP
20	Shell Energy North America (US), L.P.	Sierra Pacific Power	Avista	NF
21	Shell Energy North America (US), L.P.	Sierra Pacific Power	Sierra Pacific Power	NF
22	Shell Energy North America (US), L.P.	Sierra Pacific Power	Sierra Pacific Power	SFP
23	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
24	Shell Energy North America (US), L.P.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
25	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
26	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
27	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
28	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
29	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	SFP
30	Shell Energy North America (US), L.P.			AD
31	Sierra Pacific Power Co.	PacifiCorp East	Sierra Pacific Power	NF
32	Sierra Pacific Power Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Sierra Pacific Power Co.	PacifiCorp East	Sierra Pacific Power	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Sierra Pacific Power Co.	Idaho Power Company	Sierra Pacific Power	NF
2	Sierra Pacific Power Co.	Avista	Sierra Pacific Power	NF
3	Sierra Pacific Power Co.	Sierra Pacific Power	PacifiCorp East	NF
4	Sierra Pacific Power Co.	Sierra Pacific Power	Bonneville Power Administration	NF
5	Sierra Pacific Power Co.			AD
6	Southern California Edison	PacifiCorp East	Sierra Pacific Power	NF
7	Southern California Edison	Bonneville Power Administration	PacifiCorp East	NF
8	Southern California Edison			AD
9	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
12	Tenaska Power Services Co.	PacifiCorp East	Bonneville Power Administration	NF
13	Tenaska Power Services Co.	PacifiCorp West	PacifiCorp East	NF
14	Tenaska Power Services Co.	PacifiCorp West	PacifiCorp East	SFP
15	Tenaska Power Services Co.	Bonneville Power Administration	PacifiCorp East	NF
16	Tenaska Power Services Co.	Bonneville Power Administration	PacifiCorp East	NF
17	Tenaska Power Services Co.	Bonneville Power Administration	Sierra Pacific Power	NF
18	Tenaska Power Services Co.	Avista	PacifiCorp East	NF
19	Tenaska Power Services Co.	Avista	Sierra Pacific Power	NF
20	Tenaska Power Services Co.			AD
21	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
22	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
23	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
24	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
25	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Idaho Power Company	NF
26	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
27	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
28	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
31	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
32	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
33	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
2	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
3	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
4	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Idaho Power Company	NF
5	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
6	Transalta Energy Marketing (U.S.) Inc.			AD
7	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	NF
8	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
9	Utah Associated Municipal Power	Sierra Pacific Power	PacifiCorp East	NF
10	Utah Associated Municipal Power			AD
11				
12				
13				
14				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.
9				333,238	333,238	1
9						2
9				267,961	267,961	3
9						4
9				1,236,894	1,236,894	5
9						6
9						7
Legacy	Minidoka, Idaho	Various in Idaho		8,846	8,846	8
4				308,061	308,061	9
9				2,049	2,049	10
9						11
Legacy	LaGrande, Oregon	Various in Idaho		16,782	16,782	12
5/6	JEFF	IPCO		15,555	15,555	13
5/6	BRDY	IPCO		3,764	3,764	14
8	JEFF	LOLO		798	798	15
8						16
8	BPAT.NWMT	BRDY		25	25	17
8						18
8	BPAT.NWMT	M345		1,719	1,719	19
8	LAGRANDE	LAGRANDE		1,079	1,079	20
8	LAGRANDE	M345		34,394	34,394	21
8	LOLO	LAGRANDE		322	322	22
8	LOLO	M345		5,429	5,429	23
8						24
8	AVAT.NWMT	M345		46	46	25
8	BORA	BPAT.NWMT		818	818	26
8	BORA	LAGRANDE		4,923	4,923	27
8	BPAT.NWMT	LAGRANDE		775	775	28
8	BPAT.NWMT	M345		944	944	29
8	BRDY	M345		396	396	30
8	ENPR	BORA		740	740	31
7	ENPR	BORA		1,269	1,269	32
8	ENPR	M345		916	916	33
						34
			0	**6,721,533**	**6,721,533**	

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.
7	ENPR	M345		320	320	1
8	JBSN	BORA		467	467	2
8	JBSN	BPAT.NWMT		20	20	3
8	JBSN	LAGRANDE		735	735	4
8	JBSN	M345		160	160	5
8	JEFF	M345		254	254	6
8	LAGRANDE	BORA		468	468	7
8	LAGRANDE	M345		667	667	8
8	LOLO	BORA		984	984	9
7	LOLO	BORA		1,318	1,318	10
8	LOLO	LAGRANDE		25	25	11
8	LOLO	M345		66,652	66,652	12
7	LOLO	M345		5,416	5,416	13
8	M345	LAGRANDE		1,400	1,400	14
8						15
8						16
8						17
8	BORA	M345		62	62	18
8	BPAT.NWMT	BORA		120	120	19
8	BPAT.NWMT	BRDY		49	49	20
8	BPAT.NWMT	M345		1,969	1,969	21
8	HMWY	BORA		3,541	3,541	22
8	HMWY	M345		2,714	2,714	23
8	JEFF	M345		100	100	24
8	LAGRANDE	BORA		4,321	4,321	25
8	LAGRANDE	M345		25,422	25,422	26
8	LOLO	BORA		412	412	27
8	LOLO	M345		263	263	28
8	M345	LAGRANDE		1,834	1,834	29
8	OBBLPR	LAGRANDE		20	20	30
8						31
8						32
8	AVAT.NWMT	BRDY		417	417	33
						34
			0	**6,721,533**	**6,721,533**	

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.
8	AVAT.NWMT	HMWY		87	87	1
8	AVAT.NWMT	LAGRANDE		51	51	2
8	AVAT.NWMT	M345		22,002	22,002	3
7	AVAT.NWMT	M345		47,695	47,695	4
8	BORA	BPAT.NWMT		281	281	5
8	BORA	HMWY		45	45	6
8	BORA	JEFF		25	25	7
8	BORA	LAGRANDE		426	426	8
8	BORA	M345		7,224	7,224	9
8	BPAT.NWMT	BORA		638	638	10
8	BPAT.NWMT	BRDY		96	96	11
8	BPAT.NWMT	ENPR		360	360	12
8	BPAT.NWMT	HMWY		75	75	13
8	BPAT.NWMT	LAGRANDE		18,742	18,742	14
8	BPAT.NWMT	M345		11,972	11,972	15
7	BPAT.NWMT	M345		3,262	3,262	16
8	BRDY	AVAT.NWMT		82	82	17
8	BRDY	BORA		2	2	18
8	BRDY	BPAT.NWMT		118	118	19
8	BRDY	HMWY		392	392	20
8	BRDY	LAGRANDE		12,636	12,636	21
8	BRDY	M345		35,780	35,780	22
7	BRDY	M345		510	510	23
8	ENPR	BRDY		30	30	24
8	GSHN	HMWY		96	96	25
8	HMWY	BORA		12,608	12,608	26
8	HMWY	BRDY		1,638	1,638	27
8	HMWY	JBSN		942	942	28
8	HMWY	M345		3,679	3,679	29
8	JBSN	BORA		1,975	1,975	30
8	JBSN	HMWY		25	25	31
8	JBSN	LAGRANDE		250	250	32
8	JBSN	M345		298	298	33
						34
			0	**6,721,533**	**6,721,533**	

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.
8	JBWT	BORA		14	14	1
8	JBWT	LAGRANDE		1,930	1,930	2
8	JBWT	M345		1,530	1,530	3
8	JEFF	BORA		2,581	2,581	4
8	JEFF	BRDY		128	128	5
8	JEFF	ENPR		258	258	6
8	JEFF	HMWY		13	13	7
8	JEFF	LAGRANDE		10,801	10,801	8
8	JEFF	M345		139,494	139,494	9
8	LAGRANDE	BORA		6,060	6,060	10
8	LAGRANDE	BRDY		2,870	2,870	11
8	LAGRANDE	JEFF		35	35	12
8	LAGRANDE	M345		22,679	22,679	13
8	LOLO	BORA		4,118	4,118	14
8	LOLO	BRDY		14	14	15
8	LOLO	JEFF		80	80	16
8	LOLO	LAGRANDE		25	25	17
8	LOLO	M345		10,415	10,415	18
7	LOLO	M345		3,572	3,572	19
8	M345	BORA		2,078	2,078	20
8	M345	BPAT.NWMT		759	759	21
8	M345	BRDY		313	313	22
8	M345	JEFF		135	135	23
8	M345	LAGRANDE		1,198	1,198	24
8						25
8	BORA	M345		594	594	26
8	BRDY	M345		7,371	7,371	27
7	BRDY	M345		4,984	4,984	28
8	JEFF	M345		4,471	4,471	29
8	LAGRANDE	M345		2,531	2,531	30
8	LOLO	M345		673	673	31
7	LOLO	M345		800	800	32
8	M345	BRDY		260	260	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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.
8	M345	HMWY		790	790	1
8	M345	LAGRANDE		1,360	1,360	2
8						3
8	BORA	ENPR		1,684	1,684	4
8	BORA	HMWY		444	444	5
7	BORA	KPRT		1,340,222	1,340,222	6
8	BORA	LAGRANDE		2,195	2,195	7
8	BRDY	BRDY		1,096	1,096	8
7	BRDY	BRDY		76	76	9
8	BRDY	ENPR		300	300	10
8	BRDY	KPRT		5,243	5,243	11
8	BRDY	LAGRANDE		500	500	12
8	ENPR	BORA		211,505	211,505	13
7	ENPR	BORA		117,399	117,399	14
8	ENPR	LAGRANDE		264	264	15
7	HMWY	M345		3,676	3,676	16
8	IPCOGEN	BORA		50	50	17
8	JBWT	BORA		1,614	1,614	18
8	JBWT	BRDY		19	19	19
7	JBWT	BRDY		162,792	162,792	20
8	JBWT	GSHN		36,135	36,135	21
7	JBWT	HMWY		644,162	644,162	22
8	JBWT	KPRT		3,673	3,673	23
8	JBWT	LAGRANDE		31,250	31,250	24
8	JBWT	LOLO		123	123	25
8	LAGRANDE	BORA		292	292	26
8	LOLO	BORA		1,098	1,098	27
8	LOLO	ENPR		3,896	3,896	28
8	LOLO	LAGRANDE		3	3	29
8						30
8	BORA	BPAT.NWMT		681	681	31
8	BORA	LAGRANDE		75	75	32
8	BPAT.NWMT	LAGRANDE		15	15	33
						34
			0	**6,721,533**	**6,721,533**	

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.
8	BPAT.NWMT	M345		501	501	1
8	BRDY	LAGRANDE		13,476	13,476	2
8	HMWY	BORA		3,837	3,837	3
8	HMWY	M345		1,092	1,092	4
8	JEFF	LAGRANDE		5,919	5,919	5
8	LAGRANDE	M345		6,238	6,238	6
8	M345	LAGRANDE		719	719	7
8						8
8	BORA	BPAT.NWMT		476	476	9
8	BORA	BRDY		4	4	10
8	BORA	ENPR		32	32	11
8	BORA	HMWY		1,853	1,853	12
8	BORA	JEFF		14	14	13
8	BORA	LAGRANDE		11,765	11,765	14
8	BORA	M345		121	121	15
8	BPAT.NWMT	BORA		633	633	16
7	BPAT.NWMT	BORA		66,625	66,625	17
8	BPAT.NWMT	BRDY		157	157	18
8	BPAT.NWMT	HMWY		5	5	19
8	BPAT.NWMT	LAGRANDE		397	397	20
8	BPAT.NWMT	M345		3,564	3,564	21
8	BRDY	BPAT.NWMT		520	520	22
8	BRDY	ENPR		95	95	23
8	BRDY	HMWY		1,148	1,148	24
8	BRDY	LAGRANDE		7,809	7,809	25
8	BRDY	M345		3,974	3,974	26
8	ENPR	BORA		108,510	108,510	27
7	ENPR	BORA		87,870	87,870	28
8	ENPR	BRDY		868	868	29
8	ENPR	M345		2,887	2,887	30
8	GSHN	BPAT.NWMT		210	210	31
8	GSHN	BRDY		2	2	32
8	GSHN	HMWY		560	560	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	GSHN	JEFF		45	45	1
8	GSHN	LAGRANDE		2,927	2,927	2
8	GSHN	M345		9	9	3
8	HMWY	BORA		81,942	81,942	4
7	HMWY	BORA		22,273	22,273	5
8	HMWY	BRDY		5,275	5,275	6
8	HMWY	JBSN		50	50	7
8	HMWY	M345		35,568	35,568	8
7	HMWY	M345		4,810	4,810	9
8	JBSN	BPAT.NWMT		27	27	10
8	JBSN	JEFF		40	40	11
8	JBSN	LAGRANDE		925	925	12
8	JBSN	M345		47	47	13
8	JBWT	ENPR		40	40	14
8	JBWT	HMWY		330	330	15
8	JBWT	LAGRANDE		2,388	2,388	16
7	JEFF	BORA		624	624	17
8	JEFF	BRDY		46	46	18
8	JEFF	HMWY		445	445	19
8	JEFF	LAGRANDE		905	905	20
8	JEFF	M345		15	15	21
8	LAGRANDE	BORA		11,348	11,348	22
7	LAGRANDE	BORA		2,347	2,347	23
8	LAGRANDE	BRDY		6,767	6,767	24
8	LAGRANDE	JBSN		355	355	25
8	LAGRANDE	M345		77,404	77,404	26
7	LAGRANDE	M345		7,666	7,666	27
8	LOLO	BORA		170	170	28
8	LOLO	M345		528	528	29
8	M345	BPAT.NWMT		8	8	30
8	M345	HMWY		193	193	31
8	M345	JEFF		3	3	32
8	M345	LAGRANDE		542	542	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.
8						1
8	BPAT.NWMT	LAGRANDE		8,009	8,009	2
8	BRDY	LAGRANDE		12,328	12,328	3
8	BRDY	M345		263	263	4
8	JEFF	BORA		987	987	5
8	JEFF	LAGRANDE		10,932	10,932	6
8	JEFF	M345		175	175	7
8						8
8	HMWY	AVAT.NWMT		8	8	9
8	JBSN	LAGRANDE		1,296	1,296	10
8	JBSN	LOLO		672	672	11
8	LOLO	LAGRANDE		1,358	1,358	12
8						13
8	BORA	BPAT.NWMT		432	432	14
8	BORA	JEFF		200	200	15
7	BORA	JEFF		1,968	1,968	16
8	BRDY	AVAT.NWMT		72	72	17
8	BRDY	JEFF		150	150	18
7	BRDY	JEFF		727	727	19
8	JBSN	BRDY		200	200	20
8	LOLO	BORA		2,063	2,063	21
7	LOLO	BORA		1,380	1,380	22
8						23
8						24
8						25
8	BORA	LAGRANDE		1,065	1,065	26
8	BORA	M345		336	336	27
7	BORA	M345		756	756	28
8	BRDY	LAGRANDE		22,052	22,052	29
8	BRDY	M345		26,201	26,201	30
7	BRDY	M345		23,580	23,580	31
8	HMWY	BORA		407	407	32
8	HMWY	BRDY		1,790	1,790	33
						34
			0	**6,721,533**	**6,721,533**	

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	HMWY	M345		45,891	45,891	1
7	HMWY	M345		6,787	6,787	2
8	IPCOGEN	LAGRANDE		845	845	3
7	IPCOGEN	LAGRANDE		80	80	4
8	JBSN	LAGRANDE		8	8	5
7	JBSN	M345		2,200	2,200	6
8	JEFF	LAGRANDE		2,019	2,019	7
8	JEFF	M345		1,154	1,154	8
8	LAGRANDE	BRDY		7,743	7,743	9
8	LAGRANDE	M345		87,127	87,127	10
8	LOLO	BORA		23	23	11
8	LOLO	M345		68,925	68,925	12
7	LOLO	M345		25,524	25,524	13
8	LYPK	BORA		8,486	8,486	14
7	LYPK	BORA		2,469	2,469	15
8	LYPK	BRDY		1,339	1,339	16
8	LYPK	LAGRANDE		16,513	16,513	17
7	LYPK	LAGRANDE		96	96	18
7	LYPK	LAGRANDE		36,582	36,582	19
8	LYPK	LOLO		18	18	20
8	LYPK	M345		43,517	43,517	21
7	LYPK	M345		198,617	198,617	22
8	M345	BRDY		150	150	23
8	M345	JEFF		8	8	24
8	M345	LAGRANDE		1,655	1,655	25
8	MDSK	BORA		256	256	26
7	MDSK	BORA		3,672	3,672	27
8	MDSK	LAGRANDE		1,485	1,485	28
7	OBBLPR	LAGRANDE		400	400	29
8						30
8	BORA	M345		130	130	31
8	BPAT.NWMT	M345		556	556	32
8	BRDY	M345		50	50	33
						34
			0	**6,721,533**	**6,721,533**	

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.
8	HMWY	M345		280	280	1
8	LOLO	M345		200	200	2
8	M345	BORA		1,311	1,311	3
8	M345	LAGRANDE		361	361	4
8						5
8	BORA	M345		227	227	6
8	LAGRANDE	BORA		605	605	7
8						8
8	BPAT.NWMT	BORA		308	308	9
8	BPAT.NWMT	BRDY		846	846	10
8	BPAT.NWMT	M345		128	128	11
8	BRDY	LAGRANDE		941	941	12
8	JBSN	BRDY		342	342	13
7	JBSN	BRDY		4,736	4,736	14
8	LAGRANDE	BORA		600	600	15
8	LAGRANDE	BRDY		5	5	16
8	LAGRANDE	M345		22	22	17
8	LOLO	BORA		342	342	18
8	LOLO	M345		600	600	19
8						20
8	BRDY	LAGRANDE		90	90	21
8	LAGRANDE	BORA		563	563	22
8	LAGRANDE	BRDY		2,793	2,793	23
8	BORA	BPAT.NWMT		11	11	24
8	BORA	HMWY		429	429	25
8	BORA	LAGRANDE		3,504	3,504	26
8	BORA	M345		80	80	27
8	BPAT.NWMT	BORA		66	66	28
8	BPAT.NWMT	M345		29	29	29
8	BRDY	BPAT.NWMT		160	160	30
8	BRDY	LAGRANDE		300	300	31
8	BRDY	M345		20	20	32
8	HMWY	BORA		39,138	39,138	33
						34
			0	**6,721,533**	**6,721,533**	

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.
8	HMWY	M345		1,802	1,802	1
8	LAGRANDE	BORA		6,049	6,049	2
8	LAGRANDE	M345		4,592	4,592	3
8	M345	HMWY		50	50	4
8	M345	LAGRANDE		121	121	5
8						6
8	AVAT.NWMT	IPCO		1	1	7
8	BORA	M345		10,848	10,848	8
8	M345	BORA		27	27	9
8						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**6,721,533**	**6,721,533**	

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.
1,270,731	26,987		1,297,718	1
-20,161			-20,161	2
1,309,561	-143,134		1,166,427	3
-9,420			-9,420	4
4,630,939	56,170		4,687,109	5
-45,830			-45,830	6
-8,758			-8,758	7
	14,330		14,330	8
	184,783		184,783	9
8,018	1,307		9,325	10
-114			-114	11
54,702			54,702	12
	18,455		18,455	13
	4,466		4,466	14
	2,080		2,080	15
	-69		-69	16
	117		117	17
	-51		-51	18
	6,616		6,616	19
	4,153		4,153	20
	132,383		132,383	21
	1,239		1,239	22
	20,896		20,896	23
	-989		-989	24
	143		143	25
	2,537		2,537	26
	15,268		15,268	27
	2,404		2,404	28
	2,928		2,928	29
	1,228		1,228	30
	2,295		2,295	31
	3,936		3,936	32
	2,841		2,841	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	992		992	1
	1,448		1,448	2
	62		62	3
	2,280		2,280	4
	496		496	5
	788		788	6
	1,451		1,451	7
	2,069		2,069	8
	3,052		3,052	9
	4,088		4,088	10
	78		78	11
	206,715		206,715	12
	16,797		16,797	13
	4,342		4,342	14
	-18,793		-18,793	15
	-349		-349	16
	-20		-20	17
	259		259	18
	502		502	19
	205		205	20
	8,237		8,237	21
	14,813		14,813	22
	11,353		11,353	23
	418		418	24
	18,076		18,076	25
	106,346		106,346	26
	1,724		1,724	27
	1,100		1,100	28
	7,672		7,672	29
	84		84	30
	-395		-395	31
	-10		-10	32
	1,617		1,617	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	337		337	1
	198		198	2
	85,333		85,333	3
	184,982		184,982	4
	1,090		1,090	5
	175		175	6
	97		97	7
	1,652		1,652	8
	28,018		28,018	9
	2,474		2,474	10
	372		372	11
	1,396		1,396	12
	291		291	13
	72,690		72,690	14
	46,433		46,433	15
	12,651		12,651	16
	318		318	17
	8		8	18
	458		458	19
	1,520		1,520	20
	49,008		49,008	21
	138,770		138,770	22
	1,978		1,978	23
	116		116	24
	372		372	25
	48,899		48,899	26
	6,353		6,353	27
	3,653		3,653	28
	14,269		14,269	29
	7,660		7,660	30
	97		97	31
	970		970	32
	1,156		1,156	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	54		54	1
	7,485		7,485	2
	5,934		5,934	3
	10,010		10,010	4
	496		496	5
	1,001		1,001	6
	50		50	7
	41,891		41,891	8
	541,018		541,018	9
	23,503		23,503	10
	11,131		11,131	11
	136		136	12
	87,959		87,959	13
	15,971		15,971	14
	54		54	15
	310		310	16
	97		97	17
	40,394		40,394	18
	13,854		13,854	19
	8,059		8,059	20
	2,944		2,944	21
	1,214		1,214	22
	524		524	23
	4,646		4,646	24
	-5,250		-5,250	25
	2,419		2,419	26
	30,019		30,019	27
	20,298		20,298	28
	18,208		18,208	29
	10,308		10,308	30
	2,741		2,741	31
	3,258		3,258	32
	1,059		1,059	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,217		3,217	1
	5,539		5,539	2
	-28		-28	3
	10,055		10,055	4
	2,651		2,651	5
				6
	13,106		13,106	7
	6,544		6,544	8
	454		454	9
	1,791		1,791	10
	31,305		31,305	11
	2,985		2,985	12
	1,262,864		1,262,864	13
	700,972		700,972	14
	1,576		1,576	15
	21,949		21,949	16
	299		299	17
	9,637		9,637	18
	113		113	19
	972,006		972,006	20
	215,757		215,757	21
	3,846,194		3,846,194	22
	21,931		21,931	23
	186,589		186,589	24
	734		734	25
	1,744		1,744	26
	6,556		6,556	27
	23,262		23,262	28
	18		18	29
	-106,595		-106,595	30
	3,035		3,035	31
	334		334	32
	67		67	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,232		2,232	1
	60,049		60,049	2
	17,098		17,098	3
	4,866		4,866	4
	26,375		26,375	5
	27,797		27,797	6
	3,204		3,204	7
	-145		-145	8
	2,036		2,036	9
	17		17	10
	137		137	11
	7,926		7,926	12
	60		60	13
	50,321		50,321	14
	518		518	15
	2,707		2,707	16
	284,966		284,966	17
	672		672	18
	21		21	19
	1,698		1,698	20
	15,244		15,244	21
	2,224		2,224	22
	406		406	23
	4,910		4,910	24
	33,400		33,400	25
	16,997		16,997	26
	464,115		464,115	27
	375,835		375,835	28
	3,713		3,713	29
	12,348		12,348	30
	898		898	31
	9		9	32
	2,395		2,395	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	192		192	1
	12,519		12,519	2
	38		38	3
	350,480		350,480	4
	95,265		95,265	5
	22,562		22,562	6
	214		214	7
	152,130		152,130	8
	20,573		20,573	9
	115		115	10
	171		171	11
	3,956		3,956	12
	201		201	13
	171		171	14
	1,411		1,411	15
	10,214		10,214	16
	2,669		2,669	17
	197		197	18
	1,903		1,903	19
	3,871		3,871	20
	64		64	21
	48,537		48,537	22
	10,039		10,039	23
	28,944		28,944	24
	1,518		1,518	25
	331,070		331,070	26
	32,789		32,789	27
	727		727	28
	2,258		2,258	29
	34		34	30
	825		825	31
	13		13	32
	2,318		2,318	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	-34,259		-34,259	1
	34,098		34,098	2
	52,486		52,486	3
	1,120		1,120	4
	4,202		4,202	5
	46,542		46,542	6
	745		745	7
	-1,188		-1,188	8
	25		25	9
	4,055		4,055	10
	2,103		2,103	11
	4,249		4,249	12
	-720		-720	13
	1,522		1,522	14
	705		705	15
	6,934		6,934	16
	254		254	17
	528		528	18
	2,561		2,561	19
	705		705	20
	7,268		7,268	21
	4,862		4,862	22
	-2,844		-2,844	23
	-23,282		-23,282	24
	-1,145		-1,145	25
	4,717		4,717	26
	1,488		1,488	27
	3,349		3,349	28
	97,680		97,680	29
	116,058		116,058	30
	104,448		104,448	31
	1,803		1,803	32
	7,929		7,929	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	203,275		203,275	1
	30,063		30,063	2
	3,743		3,743	3
	354		354	4
	35		35	5
	9,745		9,745	6
	8,943		8,943	7
	5,112		5,112	8
	34,298		34,298	9
	385,931		385,931	10
	102		102	11
	305,305		305,305	12
	113,059		113,059	13
	37,589		37,589	14
	10,936		10,936	15
	5,931		5,931	16
	73,145		73,145	17
	425		425	18
	162,041		162,041	19
	80		80	20
	192,760		192,760	21
	879,779		879,779	22
	664		664	23
	35		35	24
	7,331		7,331	25
	1,134		1,134	26
	16,265		16,265	27
	6,578		6,578	28
	1,772		1,772	29
	-1,783		-1,783	30
	557		557	31
	2,381		2,381	32
	214		214	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	1,199		1,199	1
	856		856	2
	5,613		5,613	3
	1,546		1,546	4
	-14,169		-14,169	5
	1,125		1,125	6
	2,999		2,999	7
	-4		-4	8
	1,000		1,000	9
	2,747		2,747	10
	416		416	11
	3,056		3,056	12
	1,111		1,111	13
	15,380		15,380	14
	1,948		1,948	15
	16		16	16
	71		71	17
	1,111		1,111	18
	1,948		1,948	19
	-96		-96	20
	381		381	21
	2,382		2,382	22
	11,818		11,818	23
	43		43	24
	1,696		1,696	25
	13,854		13,854	26
	316		316	27
	261		261	28
	115		115	29
	633		633	30
	1,186		1,186	31
	79		79	32
	154,739		154,739	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	7,125		7,125	1
	23,916		23,916	2
	18,155		18,155	3
	198		198	4
	478		478	5
	-419		-419	6
	5		5	7
	40,577		40,577	8
	101		101	9
	-164		-164	10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30,2028. The billing demand for network servics is the customers demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expired December 31,2014 and was subsequently renewed, with a new expiration date of 12/31/23. The billing demand for network service is the customers demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Open Access Transmission tariff, Schedule 9 Network Integration Transmission Service.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30,2028. The billing demand for network service is the customer's demand at the time of Idaho power Company transmission system peak and varies by month.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

Legacy, contract prior to the Open Access Transmission Tariff.

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

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

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

4, Open Access Transmission Tariff, Schedule 4 Energy Imbalance Service.

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

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

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31,2016.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

Schedule Page: 328 Line No.: 12 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.: 13 Column: e

5/6, Open Access Transmission Tariff,Schedule 5/6 Operating Reserves.

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

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

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

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

Schedule Page: 328 Line No.: 15 Column: e

7/8, Open Access Transmission Tariff, Schedule 7/8 Point-to-Point Transmission Service.

Schedule Page: 328 Line No.: 16 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328 Line No.: 18 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328 Line No.: 24 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 10 Column: e
7/8, Open Access Transmission tariff, Schedule 7/8 Point-to-Point Transmission Service.
Schedule Page: 328.1 Line No.: 15 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 16 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 17 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 31 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 32 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.3 Line No.: 25 Column: h
Rate Refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.4 Line No.: 3 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.4 Line No.: 6 Column: h
Legacy agrement providing OATT-like service, but billed under 454 facilities revenue.
Schedule Page: 328.4 Line No.: 30 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.5 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 1 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 12 Column: h
Rate fefund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 23 Column: h
Rate refund for June 2006, thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 24 Column: h
Rate refund for June 2006 Thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 25 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.8 Line No.: 30 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 5 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 20 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rat Audit.
Schedule Page: 328.10 Line No.: 6 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	30,392	30,392		193,324		193,324
2	Avista Corp-WWP Div	SFP	217,709	217,709		941,879		941,879
3	Avista Corp-WWP Div	AD					-124	-124
4	Bonneville Power Admin	LFP	1,036,928	1,036,928		3,701,617		3,701,617
5	Bonneville Power Admin	SFP	1,840	1,840		9,200		9,200
6	Bonneville Power Admin	NF	364	364		1,820		1,820
7	Bonneville Power Admin	OS	4,220	4,220		21,804		21,804
8	Bonneville Power Admin	OS					3,743	3,743
9	Cargill Power Markets	OS					-420	-420
10	Exelon Generation Co	OS					-70,383	-70,383
11	Ierdrola Renewables	OS					-870	-870
12	Morgan Stanley Capital	OS					-16,664	-16,664
13	NextEra Energy	OS					-6,796	-6,796
14	Northwestern Energy	LFP	4,808	4,808		49,900		49,900
15	NorthWesern Energy	NF	1,716	1,716		5,938		5,938
16	NorthWestern Energy	SFP	14,027	14,027		130,363		130,363
	TOTAL		1,493,306	1,493,306		6,340,973	-259,674	6,081,299

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.	LFP	79,660	79,660		779,022		779,022
2	PacifiCorp Inc.	NF	53,945	53,945		291,828		291,828
3	PacifiCorp Inc.	SFP	5,880	5,880		37,134		37,134
4	PaifiCorp Inc.	OS				151,304		151,304
5	PacifiCorp Inc	OS				-41,600		-41,600
6	Powerex Corp.	OS					-136,828	-136,828
7	Puget Sound Energy, Inc	SFP	40,217	40,217		65,040		65,040
8	Sierra Pacific Power Co	NF					-336	-336
9	Snohomish County PUD	SFP	1,200	1,200		1,800		1,800
10	TransAlta Energy U.S.	SFP	400	400		600		600
11	TransAlta Eenrgy U.S.	OS					-30,996	-30,996
12								
13								
14								
15								
16								
	TOTAL		1,493,306	1,493,306		6,340,973	-259,674	6,081,299

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

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

Schedule Page: 332 Line No.: 8 Column: a
Reserves Provided.

Schedule Page: 332 Line No.: 9 Column: a
Resale Transmission

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

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

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

Schedule Page: 332 Line No.: 13 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 14 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332.1 Line No.: 1 Column: b
Contract Expiration Date 05/31/2019

Schedule Page: 332.1 Line No.: 5 Column: a
2012/2013 PTP True Up - PacifiCorp

Schedule Page: 332.1 Line No.: 6 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 8 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 11 Column: a
Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	453,508
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,682,703
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	67,304
6	Stephen Allred	32,475
7	Thomas Carlile	54,585
8	Richard Dahl	87,057
9	Ronald Jibson	69,622
10	Judith Johnson	74,317
11	Dennis Johnson	69,518
12	J Lamont Keen	38,577
13	Christine King	87,459
14	Jan Packwood	59,865
15	Joan Smith	81,611
16	Robert Tinstman	156,865
17	Thomas Willford	70,729
18		
19	Accociated Taxpayers of Idaho	23,000
20	Boston College for Corporations	5,000
21	Business Plus	5,000
22	Ceati International	13,050
23	Corporate Executive Board	86,120
24	Idaho Association of Commerce & industry	14,000
25	Idaho Technology Council	12,750
26	National Association of Directors	7,125
27	National Hydropower Assoc	33,482
28	North American Energy Standard	7,000
29	Northwest Power pool	279,952
30	Pacific NW Utilities	38,869
31	Utility Variable Generation industry	5,000
32	Western Energy Coordinating Council	1,163,224
33	Western Energy Institute	30,568
34	Misc Memberships under $2,000 (7)	5,915
35		
36	Chambers of Commerce & Other Civic Organizations	91,165
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	4,907,415

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Mgmt Services	$ 75,181
Broadridge Financial Solutions	Proxy & Bulletin	49,240
Deutsche Bank	Broker Fees	43,482
E Source	Mgmt Services	35,756
Moody's Analytics	Mgmt Services	32,729
NASDAQ Corp Solutions	Mgmt Services	70,138
New York Stock Exchange	Listing Services	46,628
Rate Related Amortization	Misc Expense	230,655
Stock Based Compensation	Misc Expense	752,952
Wells Fargo Shareowner Service	Mgmt Services	115,889
Payroll Related Expenses	Misc Expense	167,051
Miscellaneous		63,002
Total		$1,682,703

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)

(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,172,382		7,172,382
2	Steam Production Plant	24,519,352	495,029			25,014,381
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,054,949				14,054,949
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,190,565				17,190,565
7	Transmission Plant	20,082,639				20,082,639
8	Distribution Plant	40,300,184				40,300,184
9	Regional Transmission and Market Operation					
10	General Plant	9,097,851				9,097,851
11	Common Plant-Electric					
12	TOTAL	125,245,540	495,029	7,172,382		132,912,951

B. Basis for Amortization Charges

Acct 404	Balance 1/1/14	2014 Amortization	Balance 12/31/14	Remaining months
(1)	48,000	12,000	36,000	36
(2)	11,885,442	545,446	10,339,996	-
(3)	5,468,500	189,366	5,251,629	333
(4)	19,158,412	6,115,880	15,747,708	-
(5)	4,035,897	287,899	3,747,997	168
(6)	209,847	8,026	201,821	-
(7)	618,074	13,765	604,625	-
	------------------	-------------	-------------	
Total	40,424,173	7,611,634	35,929,777	

(1) Shoshone-Bannock Tribe License & Use Agreement (Termination date December 31, 2023).
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period).
(3) Swan Falls Relicensing (Amortized over a 30 year license period).
(4) Computer Software packages (Amortized over a 60 month period from date of purchase).
(5) Shoshone-Bannock Right of Way (Termination date December 31, 2028).
(6) Boardman Retrofit Tech Analysis (Termination date December 31, 2040).
(7) FERC License Complianc Costs (Termination date will be expirtion date of the FERC Licenses).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	638	75.00		3.64	R4.0	20.20
13	311.00	150,084	100.00	-10.00	1.89	S1.0	21.30
14	312.10	81,618	60.00	-5.00	1.43	R3.0	21.80
15	312.20	509,205	60.00	-5.00	2.70	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.35	R3.0	7.90
17	314.00	159,337	45.00	-5.00	3.24	S1.0	19.40
18	315.00	70,043	60.00		1.45	S1.5	19.80
19	316.00	11,737	45.00	-5.00	3.68	R0.5	19.00
20	316.10	84	12.00	15.00	8.72	L2.0	6.30
21	316.40	247	12.00	15.00	0.82	L2.0	7.90
22	316.50	83	12.00	15.00	3.19	L2.0	5.10
23	316.60	106	20.00	15.00	4.76	L2.0	18.00
24	316.70	80	20.00	15.00	2.87	L2.0	14.40
25	316.80	3,583	20.00	30.00	3.53	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	6,372					
28	Subtotal Steam	997,572					
29	331.00	175,002	100.00	-25.00	2.38	R2.5	33.00
30	332.10	19,461	95.00	-20.00	1.31	S4.0	39.80
31	332.20	237,646	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	SQUARE	49.10
33	333.00	207,191	80.00	-5.00	1.72	R3.0	32.60
34	334.00	56,828	50.00	-5.00	2.71	R1.5	26.10
35	335.00	21,069	95.00		2.25	R2.0	28.10
36	335.10	93	15.00		6.86	SQUARE	6.50
37	335.20	366	20.00		5.76	SQUARE	5.30
38	335.30	242	5.00		12.16	SQUARE	3.30
39	336.00	9,585	75.00		2.33	R3.0	21.40
40	Subtotal Hydro	732,955					
41	341.00	140,902			2.83	SQUARE	27.20
42	342.00	10,453	50.00		2.57	S2.5	28.50
43	343.00	238,896	40.00		3.33	S1.5	25.90
44	344.00	66,355	45.00		2.64	S2.0	26.80
45	345.00	88,608	50.00		3.39	S1.5	22.60
46	346.00	6,247	35.00		3.28	S2.5	24.50
47	Subtotal Other	551,461					
48	350.20	31,604	70.00		1.39	R3.0	58.80
49	350.22	115	30.00		3.33		
50	352.00	72,738	65.00	-35.00	1.84	R3.0	53.70

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	353.00	399,788	50.00	-5.00	1.90	R1.5	40.70
13	354.00	168,187	65.00	-15.00	1.70	S3.0	50.80
14	355.00	142,598	60.00	-70.00	2.77	R2.0	43.60
15	356.00	196,361	65.00	-40.00	2.25	R2.0	48.50
16	359.00	390	65.00		0.79	R2.5	24.00
17	Subtotal Transmission	1,011,781					
18	360.22	348	30.00		3.33		30.00
19	361.00	33,717	65.00	-40.00	2.14	R2.5	53.30
20	362.00	202,030	50.00	-5.00	2.00	R1.0	40.20
21	364.00	241,031	44.00	-45.00	3.08	R1.5	31.30
22	364.10	58	12.00		8.34		
23	365.00	128,008	45.00	-35.00	2.98	R0.5	33.60
24	366.00	47,294	60.00	-20.00	1.95	R2.0	48.40
25	367.00	218,657	46.00	-15.00	2.26	R2.0	35.30
26	368.00	494,615	35.00	-3.00	2.58	R1.0	27.00
27	369.00	57,867	40.00	-40.00	2.55	R2.0	29.50
28	370.00	16,483	22.00	1.00	3.46	O1.0	17.50
29	370.10	64,046	15.00		6.96	S2.5	13.10
30	371.10		12.00	-2.00		S4.0	9.00
31	371.20	2,915	17.00	-2.00	1.51	R1.5	14.70
32	373.20	4,505	30.00	-25.00	2.41	R1.0	20.60
33	374.00	534					
34	Subtotal Distribution	1,512,108					
35	390.11	28,255	100.00	-5.00	2.58	S0.5	28.80
36	390.12	78,578	55.00	-5.00	1.90	S0.5	44.30
37	390.20	205	35.00		2.15	S3.0	25.70
38	391.11	14,135	20.00		2.88	SQUARE	12.90
39	391.20	24,364	5.00		11.12	SQUARE	3.20
40	391.21	7,404	8.00		11.22	L2.0	5.70
41	392.10	841	12.00	15.00	7.50	L2.0	8.90
42	392.30	2,920	10.00	50.00	1.73	S2.5	3.40
43	392.40	23,547	12.00	15.00	7.36	L2.0	6.80
44	392.50	1,123	12.00	15.00	3.53	L2.0	9.00
45	392.60	34,652	20.00	15.00	4.14	L2.0	13.40
46	392.70	6,304	20.00	15.00	3.21	L2.0	12.50
47	392.90	4,826	35.00	15.00	2.10	S1.0	24.30
48	393.00	1,936	25.00		3.30	SQUARE	19.40
49	394.00	7,575	20.00		4.13	SQUARE	13.30
50	395.00	12,652	20.00		4.29	SQUARE	12.10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	396.00	13,938	20.00	30.00	1.66	O1.0	17.60
13	397.10	4,913	15.00		4.25	SQUARE	8.30
14	397.20	32,820	15.00		5.38	SQUARE	9.80
15	397.30	4,330	15.00		5.31	SQUARE	8.00
16	397.40	11,725	10.00		7.90	SQUARE	6.50
17	398.00	5,577	15.00		5.20	SQUARE	10.60
18	Subtotal General	322,620					
19	Total Plant	5,128,497					
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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	04/15/2015	End of 2014/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	2,598,261		2,598,261	
3					
4	Regulatory FERC fees Tru-up		-89,330	-89,330	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		743,604	743,604	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Rate Case - Misc expenses		-21,427	-21,427	
13					
14	Regulatory Commission Expenses - Oregon				
15	Rate Case - Misc expenses		843	843	
16	General Regulatory		58,643	58,643	
17	Other OPUC expenses		8,743	8,743	
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46	TOTAL	2,756,762	701,076	3,457,838	

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	2,598,261					2
							3
Electric	928	-89,330					4
							5
							6
Electric	928	743,604					7
							8
Electric	928	158,501					9
							10
							11
Electric	928	-21,427					12
							13
							14
Electric	928	843					15
Electric	928	58,643					16
Electric	928	8,743					17
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		3,457,838					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Idaho Power did not incur any Research and	
2	Development expenditures in 2014.	
3		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	22,607,567		
4	Transmission	6,826,884		
5	Regional Market			
6	Distribution	17,605,437		
7	Customer Accounts	11,413,469		
8	Customer Service and Informational	4,849,214		
9	Sales			
10	Administrative and General	43,649,783		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	106,952,354		
12	Maintenance			
13	Production	4,940,951		
14	Transmission	3,388,364		
15	Regional Market			
16	Distribution	8,231,515		
17	Administrative and General	1,000,896		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,561,726		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,548,518		
21	Transmission (Enter Total of lines 4 and 14)	10,215,248		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,836,952		
24	Customer Accounts (Transcribe from line 7)	11,413,469		
25	Customer Service and Informational (Transcribe from line 8)	4,849,214		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	44,650,679		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	124,514,080		124,514,080
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	04/15/2015	End of 2014/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	124,514,080		124,514,080
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
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	5,014,170		5,014,170
79	Other clearing accounts	3,055,719		3,055,719
80	Construction Work in Progress	53,485,019		53,485,019
81	Other Work in Progress	2,847,464		2,847,464
82	Paid Absences	22,802,332		22,802,332
83	Preliminary Survey and Investigation	760		760
84	Other Accounts	5,388,094		5,388,094
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	92,593,558		92,593,558
96	TOTAL SALARIES AND WAGES	217,107,638		217,107,638

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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45					
46	TOTAL				

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,791	6	800	3,687	217	567		320	
2	February	4,709	4	800	3,597	220	567		325	
3	March	4,377	19	900	3,097	190	567		523	
4	Total for Quarter 1	13,877			10,381	627	1,701		1,168	
5	April	4,181	7	800	2,827	159	567		628	
6	May	4,818	26	2100	3,488	284	567		479	
7	June	5,496	24	1700	4,364	342	567		223	
8	Total for Quarter 2	14,495			10,679	785	1,701		1,330	
9	July	5,816	14	1400	4,769	357	463		227	
10	August	5,329	11	1600	4,413	274	463		179	
11	September	4,979	16	1700	4,092	248	463		176	
12	Total for Quarter 3	16,124			13,274	879	1,389		582	
13	October	4,175	8	1800	3,345	162	463		205	
14	November	4,792	18	800	4,012	244	463		73	
15	December	4,702	30	1900	3,896	234	463		109	
16	Total for Quarter 4	13,669			11,253	640	1,389		387	
17	Total Year to Date/Year	58,165			45,587	2,931	6,180		3,467	

Schedule Page: 400   Line No.: 17   Column: e

Includes 1836 MW associated with pre-Order No. 888 transmission agreements between PacifiCorp and Idaho Power. The contract demand associated with the pre-Order No. 888 transmission agreements is part of Idaho Power's total firm load and is included in the load denominator in the computation of, and accordance with, Idaho Power's Open Access Transmission Tariff ("OATT") rate. On October 24, 2014, the Parties entered into a Joint Purchase and Sale Agreement and a Termination Agreement that will, if closing occurs, result in the elimination of 1836 MW of contract demand that is associated with the pre-Order No. 888 transmission agreements that terminate as part of the transaction. In addition, 310 MW of Firm Point-To-Point Transmission Service Agreements will become effective if closing occurs. The Parties anticipate all required regulatory approvals will be received and the transaction will close no later than September, 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,092,367
3	Steam	5,850,665			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	6,169,847			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,220,419
7	Other	1,174,857			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,195,369	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	4,148,611	27	Total Energy Losses	1,144,985
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,457,771
12	Received	324,803			
13	Delivered	211,221			
14	Net Exchanges (Line 12 minus line 13)	113,582			
15	Transmission For Other (Wheeling)				
16	Received	6,721,533			
17	Delivered	6,721,324			
18	Net Transmission for Other (Line 16 minus line 17)	209			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,457,771			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	1,523,503	240,689	2,175	6	9 AM
30	February	1,399,729	314,599	2,204	6	8 AM
31	March	1,328,178	260,659	1,843	12	8 AM
32	April	1,231,532	164,970	1,816	24	10 AM
33	May	1,412,244	82,077	2,436	27	7 PM
34	June	1,636,434	114,271	2,781	23	7 PM
35	July	1,875,812	47,418	3,184	8	6 PM
36	August	1,635,278	199,356	2,949	1	5 PM
37	September	1,398,021	186,995	2,434	16	6 PM
38	October	1,236,921	195,349	1,735	7	6 PM
39	November	1,352,620	207,977	2,253	18	8 AM
40	December	1,423,437	206,059	2,205	31	10 AM
41	TOTAL	17,453,709	2,220,419			

Schedule Page: 401 Line No.: 5 Column: b

The sum of line 12 on pages 406 thru 407 is different than the total on page 401 by 72,413 Mw. The 72,413 Mw is made up of Clear Lakes Power Plant 16,963 Mw and Thousand Springs Power Plant 55,450 Mw. Thousand Springs and Clear lakes is included in the total on page 401 line 5 but they are not included on pages 406-407. They are not included on page 406-407 because plants generating less than 10 Mw are excluded, per instruction 1 on page 406.

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

Page 329 Column I differs from Page 401 by 209 MWH, reported for Lucky Peak variation and BPA Energy imbalalnce schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only. However the numbers on page 401 have to be adjusted for account 447 transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.20		
6	Net Peak Demand on Plant - MW (60 minutes)	734			62		
7	Plant Hours Connected to Load	8760			6585		
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	4651499000			269335000		
13	Cost of Plant: Land and Land Rights	499457			106610		
14	Structures and Improvements	68495219			12408084		
15	Equipment Costs	480941021			63479074		
16	Asset Retirement Costs	2640264			4348222		
17	Total Cost	552575961			80341990		
18	Cost per KW of Installed Capacity (line 17/5) Including	717.1654			1251.4329		
19	Production Expenses: Oper, Supv, & Engr	265285			537592		
20	Fuel	118487670			6671067		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5361847			777278		
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	6727902			1020470		
27	Rents	529967			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	77787			198355		
30	Maintenance of Structures	0			65928		
31	Maintenance of Boiler (or reactor) Plant	7416751			262078		
32	Maintenance of Electric Plant	3164373			2123156		
33	Maintenance of Misc Steam (or Nuclear) Plant	5669116			24292		
34	Total Production Expenses	147700698			11680216		
35	Expenses per Net KWh	0.0318			0.0434		
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	2587129	4065	0	161681	1761	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9174	140000	0	8459	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.327	158.528	0.000	41.067	122.529	0.000
41	Average Cost of Fuel per Unit Burned	45.490	118.042	0.000	39.740	126.340	0.000
42	Average Cost of Fuel Burned per Million BTU	2.464	20.075	0.000	2.399	21.673	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	10274.000	0.000	0.000	9983.000	0.000	0.000

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

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

Line No.	Item (a)	Plant Name: *Langley Gulch* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2012	
4	Year Last Unit was Installed	2012	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	318.45	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	305	0
7	Plant Hours Connected to Load	4027	0
8	Net Continuous Plant Capability (Megawatts)	300	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	21	0
12	Net Generation, Exclusive of Plant Use - KWh	1049182000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	133486018	0
15	Equipment Costs	241890950	0
16	Asset Retirement Costs	0	0
17	Total Cost	377664229	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1185.9451	0
19	Production Expenses: Oper, Supv, & Engr	505916	0
20	Fuel	36289736	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2851598	0
26	Misc Steam (or Nuclear) Power Expenses	301718	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	95463	0
31	Maintenance of Boiler (or reactor) Plant	39718	0
32	Maintenance of Electric Plant	825878	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	40910027	0
35	Expenses per Net KWh	0.0390	0.0000

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	7121881	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1027	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.096	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.096	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.370	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	6971.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

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

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2008			2005			4
283.50			270.90			172.80			5
260			244			191			6
6359			414			533			7
0			261			164			8
0			0			0			9
0			0			0			10
0			8			5			11
929831000			55192000			70483000			12
1106140			402745			1688442			13
69181061			5715935			60883807			14
296057640			106887152			0			15
-616367			0			0			16
365728474			113005832			62572249			17
1290.0475			417.1496			362.1079			18
573832			168641			10536			19
31013438			3883525			4881208			20
0			0			0			21
2602142			0			0			22
0			0			0			23
0			0			0			24
1599507			388047			349089			25
1850352			314876			158830			26
554			0			0			27
0			0			0			28
1744			0			0			29
642380			157279			125325			30
3244236			155			5733			31
757425			248261			317289			32
113006			0			0			33
42398616			5160784			5848010			34
0.0456			0.0935			0.0830			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
494841	12308	0	576521	0	0	730067	0	0	38
9407	138778	0	1027	0	0	1027	0	0	39
37.821	136.187	0.000	6.736	0.000	0.000	6.686	0.000	0.000	40
59.159	138.253	0.000	6.736	0.000	0.000	6.686	0.000	0.000	41
3.144	23.719	0.000	6.630	0.000	0.000	6.940	0.000	0.000	42
0.033	0.000	0.000	0.070	0.000	0.000	0.069	0.000	0.000	43
10089.000	0.000	0.000	10728.000	0.000	0.000	10638.000	0.000	0.000	44

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

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

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

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

Schedule Page: 403 Line No.: 3 Column: d

This footnote applies to lines 3 and 4. The Valmy plant consists of two units constructed jointly by Sierra Pacific Power Company and Idaho Power Company, with Sierra owning 1/2 and Idaho owning 1/2. Unit #1 was placed in commercial operation December 11, 1981 and Unit #2 May 21, 1985.

Schedule Page: 402 Line No.: 5 Column: b

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 402 column B.

Schedule Page: 402 Line No.: 5 Column: c

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note on line 3 page 402 column C

Schedule Page: 403 Line No.: 5 Column: d

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 403 column D.

Schedule Page: 402 Line No.: 9 Column: b

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

Schedule Page: 402 Line No.: 9 Column: c

This footnote applies to lines 9, 10, and 11. Portland General Electric Company, as operator will report this information.

Schedule Page: 403 Line No.: 9 Column: d

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	99	52
7	Plant Hours Connect to Load	4,997	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	264,207,000	301,557,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,935,359	1,094,991
16	Reservoirs, Dams, and Waterways	4,293,075	8,670,708
17	Equipment Costs	32,743,435	9,409,661
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,686,463	20,430,203
21	Cost per KW of Installed Capacity (line 20 / 5)	549.1491	272.4027
22	Production Expenses		
23	Operation Supervision and Engineering	205,189	822,283
24	Water for Power	1,397,935	666,110
25	Hydraulic Expenses	119,243	648,634
26	Electric Expenses	96,270	41,218
27	Misc Hydraulic Power Generation Expenses	298,420	404,270
28	Rents	143	11,636
29	Maintenance Supervision and Engineering	9,955	7,264
30	Maintenance of Structures	136,098	54,320
31	Maintenance of Reservoirs, Dams, and Waterways	64,125	11,304
32	Maintenance of Electric Plant	271,688	189,883
33	Maintenance of Misc Hydraulic Plant	87,987	153,050
34	Total Production Expenses (total 23 thru 33)	2,687,053	3,009,972
35	Expenses per net KWh	0.0102	0.0100

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	439	23
7	Plant Hours Connect to Load	8,760	8,756
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	1,623,091,000	95,302,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,375
15	Structures and Improvements	2,888,412	2,827,184
16	Reservoirs, Dams, and Waterways	52,966,090	6,262,987
17	Equipment Costs	19,847,008	10,262,830
18	Roads, Railroads, and Bridges	922,781	309,505
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,504,672	19,867,881
21	Cost per KW of Installed Capacity (line 20 / 5)	200.5228	912.6266
22	Production Expenses		
23	Operation Supervision and Engineering	391,480	100,191
24	Water for Power	252,820	720,714
25	Hydraulic Expenses	706,805	79,575
26	Electric Expenses	241,292	37,156
27	Misc Hydraulic Power Generation Expenses	509,470	112,164
28	Rents	31,631	0
29	Maintenance Supervision and Engineering	19,394	2,766
30	Maintenance of Structures	55,592	38,357
31	Maintenance of Reservoirs, Dams, and Waterways	108,326	16,773
32	Maintenance of Electric Plant	333,032	44,893
33	Maintenance of Misc Hydraulic Plant	427,046	55,550
34	Total Production Expenses (total 23 thru 33)	3,076,888	1,208,139
35	Expenses per net KWh	0.0019	0.0127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	34	13
7	Plant Hours Connect to Load	8,760	4,693
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	191,224,000	42,929,000
13	Cost of Plant		
14	Land and Land Rights	202,398	313,328
15	Structures and Improvements	2,069,321	1,231,506
16	Reservoirs, Dams, and Waterways	6,009,169	4,863,517
17	Equipment Costs	8,908,550	4,703,941
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,218,797	11,163,675
21	Cost per KW of Installed Capacity (line 20 / 5)	499.0956	893.0940
22	Production Expenses		
23	Operation Supervision and Engineering	318,486	183,649
24	Water for Power	241,379	142,205
25	Hydraulic Expenses	368,449	119,810
26	Electric Expenses	92,996	48,168
27	Misc Hydraulic Power Generation Expenses	285,631	233,300
28	Rents	0	28
29	Maintenance Supervision and Engineering	6,650	3,996
30	Maintenance of Structures	85,360	22,470
31	Maintenance of Reservoirs, Dams, and Waterways	25,036	875
32	Maintenance of Electric Plant	85,328	81,483
33	Maintenance of Misc Hydraulic Plant	178,270	119,901
34	Total Production Expenses (total 23 thru 33)	1,687,585	955,885
35	Expenses per net KWh	0.0088	0.0223

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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
615	14	209	6
8,760	8,750	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	7	11
1,916,947,000	43,078,000	831,631,000	12
			13
18,232,716	82,142	1,212,767	14
32,155,940	7,364,154	10,709,434	15
67,180,945	3,145,630	30,435,630	16
58,941,432	13,311,381	18,754,552	17
518,444	122,668	565,842	18
0	0	0	19
177,029,477	24,025,975	61,678,225	20
302.4077	1,934.4585	324.6222	21
			22
761,964	242,699	419,169	23
465,585	171,003	245,333	24
1,264,604	440,368	687,208	25
253,884	120,353	212,093	26
1,074,106	331,652	511,962	27
115,980	108	19,016	28
23,312	3,668	15,089	29
103,542	9,618	351,403	30
-12,186	-8	243	31
437,940	86,668	157,025	32
581,357	78,483	233,555	33
5,070,088	1,484,612	2,852,096	34
0.0026	0.0345	0.0034	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	04/15/2015	End of 2014/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
60	18	44	6
8,760	8,751	5,940	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
366,278,000	110,848,000	59,763,000	12
			13
5,476,746	229,890	255,499	14
9,681,585	27,237,723	10,980,059	15
10,806,251	15,906,987	7,975,473	16
13,419,581	30,609,794	21,200,821	17
1,602,868	835,946	1,917,603	18
0	0	0	19
40,987,031	74,820,340	42,329,455	20
495.0125	2,992.8136	802.6063	21
			22
812,529	747,525	177,450	23
641,914	568,175	133,137	24
1,127,584	1,005,213	137,881	25
46,580	33,633	65,024	26
598,565	566,126	166,856	27
61,259	10,179	3,370	28
9,179	6,935	4,052	29
167,971	70,868	31,573	30
79,491	32,468	9,182	31
158,655	153,011	101,736	32
110,131	133,731	85,426	33
3,813,858	3,327,864	915,687	34
0.0104	0.0300	0.0153	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	04/15/2015	End of 2014/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	36	44	6
0	8,757	3,868	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	197,065,000	53,514,000	12
			13
114,367	424,428	138,100	14
40,956,158	2,869,695	10,447,136	15
13,556,785	6,920,148	17,188,307	16
2,096,941	8,149,447	28,835,733	17
99,051	88,693	501,877	18
0	0	0	19
56,823,302	18,452,411	57,111,153	20
0.0000	307.5402	960.6586	21
			22
0	278,036	167,230	23
0	213,833	1,407,513	24
6,911,220	271,860	116,658	25
0	103,894	34,898	26
0	309,322	256,068	27
0	2,869	3,431	28
0	5,001	2,806	29
0	92,696	36,241	30
0	3,267	14,905	31
0	105,375	44,882	32
121,392	79,956	61,778	33
7,032,612	1,466,109	2,146,410	34
0.0000	0.0074	0.0401	35

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

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

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

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

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

Upstream storage in Brownlee Reservoir

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	2.3	16,963	3,552,785
3	Thousand Springs	1912	8.80	7.3	55,450	9,460,534
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	3.0	26	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,421,114	125,875		34,565			2
1,075,061	265,566		186,324			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
						12
						13
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						45
						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	04/15/2015	End of 2014/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Borah	Midpoint	345.00	500.00	S Tower	85.17		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.40		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		1
5								
6	Jim Bridger	Goshen	345.00	345.00	S Tower	226.16		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.06		2
8	Kinport	Borah	345.00	345.00	S Tower	27.06		1
9	Jim Bridger	Populus	345.00	345.00	S Tower			1
10	Populus	Kinport	345.00	345.00	S Tower			1
11	Jim Bridger	Populus	345.00	345.00	S Tower			1
12	Populus	Borah	345.00	345.00	S Tower			1
13	Midpoint	Borah #1	345.00	345.00	H Wood	79.30		1
14	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
15	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
16								
17	Quartz	LaGrande	230.00	230.00	H Wood	46.14		1
18	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
19	Brady	Antelope	230.00	230.00	H Wood	56.39		1
20	Brady	Treasureton	230.00	230.00	H Wood	0.08		1
21	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
22	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
23	Brownlee	Ontario	230.00	230.00	S Tower	72.67		1
24	Mora	Bowmont	138.00	230.00	S P Wood	9.91		1
25	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
26	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
27	Caldwell 710	Locust	230.00	230.00	SP Steel	18.44		1
28	Boise Bench	Caldwell	230.00	230.00	S Tower	7.58		1
29	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
30	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.91		2
31	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
32	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
33	Caldwell	Ontario	230.00	230.00	H Wood	29.97		1
34	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
35	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
36					TOTAL	4,782.11	11.02	194

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Borah	Hunt	230.00	230.00	H Steel	68.17		1
2	Danskin	Hubbard	230.00	230.00	H Steel	36.25		1
3	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
4	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
5	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.32		1
6	Hemingway	Bowmont	230.00	230.00	SP Steel	12.98		1
7	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
8	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
9	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
10	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.41		1
11	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
12	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
13	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
14	Oxbow	Brownlee	230.00	230.00	S Tower	10.32		2
15	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
16	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
17	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.02		2
18	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
19	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
20	Brownlee	Boise Bench	230.00	230.00	S Tower	102.08		2
21	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
22	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
23	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
24	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
25	Borah	Brady #1	230.00	230.00	H Wood	3.84		1
26								
27	Goshen	State Line	161.00	161.00	H Wood	90.69		1
28	Don	Goshen	161.00	161.00	S Tower	2.37		2
29	Don	Goshen	161.00	161.00	H Wood	48.42		2
30								
31	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.18		2
32	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
33	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.15		2
34	Nampa	Caldwell	138.00	138.00	S P Wood	9.58		2
35	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.35		1
36					TOTAL	4,782.11	11.02	194

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

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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	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
2	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
3	Brady	Fremont	138.00	138.00	S Tower	1.00		2
4	Brady	Fremont	138.00	138.00	H Wood	24.38		2
5	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
6	King	Lower Malad	138.00	138.00	H Wood	84.74		2
7	Emmett Jct	Payette	138.00	138.00	H Wood	66.47		2
8	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
9	Ontario	Quartz	138.00	138.00	H Wood	73.27		1
10	King	American Falls PP	138.00	138.00	S Tower	1.01		2
11	King	American Falls PP	138.00	138.00	H Wood	142.03		1
12	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
13	Duffin	Clawson	138.00	138.00	H Wood	6.19		1
14	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
15	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
16	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
17	King	Wood River	138.00	138.00	H Wood	73.60		1
18	Boise Bench	Grove	138.00	138.00	S P Wood	10.31		2
19	Quartz	John Day	138.00	138.00	H Wood	67.13		1
20	Sinker Creek Tap		138.00	138.00	H Wood	2.79		1
21	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
22	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
23	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
24	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
25	Fossil Gulch Tap		138.00	138.00	H Wood	1.81		1
26	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
27	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
28	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
29	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
30	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.47		2
31	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
32	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
33	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
34	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
35	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.21		2
36					TOTAL	4,782.11	11.02	194

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TRANSMISSION LINE STATISTICS

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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	Twin Falls	Russett	138.00	138.00	S P Wood	1.69		1
2	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
3	Peterson	Tendoy	69.00	138.00	H Wood	57.21		1
4	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
5	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.84		2
6	Boise Bench	Mora	138.00	138.00	H Wood	13.10		2
7	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
8	Gary Lane	Eagle	138.00	138.00	S P Wood	6.52		1
9	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
10	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
11	Eagle	Star	138.00	138.00	S P Wood	6.73		1
12	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.60		1
13	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
14	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
15	Butler	Wye	138.00	138.00	S P Steel	2.94		1
16	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
17	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
18	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
19	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
20	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
21	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
22	Garnet	Ward		138.00				
23	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
24	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
25	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
26	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
27	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
28	Valivue Tap		138.00	138.00	S P Steel	0.79		2
29	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.64		1
30	Kinport	Don #1	138.00	138.00	S Tower	1.32		2
31	Donn	HOKU	138.00	138.00	S P Steel	2.71		1
32	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
33	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
34	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
35	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.26		1
36					TOTAL	4,782.11	11.02	194

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	King	Justice	138.00	138.00	S P Wood	0.07		1
2	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
3	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.20		1
4	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
5	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
6	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
7	Strike Jct	Bowmont		138.00	H Wood	0.05		1
8	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
9	Strike Jct	Bowmont	138.00	138.00	H Wood	68.02		1
10	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
11	Bliss	King	138.00	138.00	H Wood	10.47		1
12	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
13	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
14								
15								
16								
17	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
18								
19								
20	69 Kv Lines		69.00	69.00	H Wood	167.03		1
21	69 Kv Lines		69.00	69.00	S P Wood	937.02		1
22								
23								
24	46 Kv Lines		46.00	46.00	S P Wood	408.37		1
25								
26	Total all lines					4,782.11	11.02	194
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,782.11	11.02	194

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	256,381	21,828,404	22,084,785					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		835,662	835,662					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,830,982	17,314,291					6
795 ACSR	571,979	11,108,161	11,680,140					7
1272 ACSR	344,220	6,008,061	6,352,281					8
1272 ACSR		10,157,447	10,157,447					9
1272 ACSR								10
1272 ACSR		1,035,143	1,035,143					11
1272 ACSR								12
715.5 ACSR	283,143	13,335,498	13,618,641					13
715.5 ACSR	64,851	15,402,643	15,467,494					14
715.5 ACSR	51,448	347,946	399,394					15
								16
795 ACSR	62,218	5,437,966	5,500,184					17
715.5 ACSR	9,145	998,452	1,007,597					18
1272 ACSR	108,301	3,415,845	3,524,146					19
795 ACSR		6,186	6,186					20
715.5 ACSR	18,829	969,871	988,700					21
1272 ACSR	1,190	51,525	52,715					22
2X954 ACSR	1,676,838	20,541,790	22,218,628					23
715.5 ACSR	413,793	2,197,386	2,611,179					24
715.5 ACSR								25
1272 ACSR	1,899	212,523	214,422					26
1590 ACSR	2,138,236	8,775,086	10,913,322					27
1272 ACSR	1,748,214	7,403,554	9,151,768					28
715.5 ACSR								29
1272 ACSR	3,062,812	6,560,901	9,623,713					30
795 AAC		89,694	89,694					31
954 ACSR	34,174	16,026,470	16,060,644					32
2X954 ACSR	236,152	9,228,893	9,465,045					33
1272 ACSR								34
1272 ACSR	81,701	1,666,354	1,748,055					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 ACSR	624,917	22,468,666	23,093,583					1
1590 ACSR		15,210,561	15,210,561					2
1590 ACSR								3
1590 ACSR								4
1590 ACSR		3,528,033	3,528,033					5
1590 ACSR	1,854,996	9,332,649	11,187,645					6
1590 ACSR	948,166	9,080,890	10,029,056					7
1272 ACSR								8
715.5 ACSR	385,287	6,739,866	7,125,153					9
715.5 ACSR								10
795 ACSR	53,068	2,833,575	2,886,643					11
795 ACSR								12
VARIOUS	289,934	8,966,987	9,256,921					13
1272 ACSR	14,810	1,237,524	1,252,334					14
715.5 ACSR	227,825	14,141,042	14,368,867					15
VARIOUS								16
1272 ACSR	87,468	4,031,934	4,119,402					17
1272 ACSR	171,081	1,651,381	1,822,462					18
1272 ACSR	44,687	1,252,130	1,296,817					19
954 ACSR	184,817	6,257,154	6,441,971					20
715.5 ACSR	247,857	5,663,803	5,911,660					21
1272 ACSR	84,014	1,867,303	1,951,317					22
1272 ACSR	3,068	416,606	419,674					23
715.5 ACSR								24
1272 ACSR	7,248	421,273	428,521					25
								26
250 COPPER	16,155	648,382	664,537					27
715.5 ACSR	88,204	2,343,558	2,431,762					28
397.5 ACSR								29
								30
250 COPPER	26,507	381,182	407,689					31
250 COPPER								32
715.5 ACSR	21,327	249,232	270,559					33
795 AAC	670,449	3,200,265	3,870,714					34
795 ACSR	47,687	3,539,654	3,587,341					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR	43,568	1,882,280	1,925,848					1
795 AAC	270,823	557,504	828,327					2
VARIOUS	564,932	4,080,596	4,645,528					3
VARIOUS								4
VARIOUS								5
VARIOUS	76,823	3,208,627	3,285,450					6
VARIOUS	33,918	2,734,762	2,768,680					7
397.5 ACSR	1,955	6,930	8,885					8
VARIOUS	34,428	5,204,281	5,238,709					9
715.5 ACSR	216,919	9,014,734	9,231,653					10
715.5 ACSR								11
715.5 ACSR								12
4\0	4,191	351,881	356,072					13
954 ACSR		96,921	96,921					14
250 COPPER	2,741	761,189	763,930					15
VARIOUS	28,490	3,049,994	3,078,484					16
VARIOUS	173,683	3,804,937	3,978,620					17
VARIOUS	225,602	1,652,772	1,878,374					18
397.5 ACSR	92,173	2,450,153	2,542,326					19
VARIOUS	20	77,199	77,219					20
715.5 ACSR	3,123,380	8,615,808	11,739,188					21
VARIOUS								22
795AAC								23
1272 ACSR								24
250 COPPER	450	187,848	188,298					25
397.5 ACSR	349,712	7,070,008	7,419,720					26
397.5 ACSR								27
397.5 ACSR	141,534	2,698,198	2,839,732					28
397.5 ACSR								29
715.5 ACSR	211,131	1,457,085	1,668,216					30
715.5 ACSR	3,324	1,416,503	1,419,827					31
397.5 ACSR	14,927	687,321	702,248					32
715.5 ACSR	13,734	1,052,339	1,066,073					33
397.5 ACSR	18,223	1,281,344	1,299,567					34
VARIOUS	54,848	3,086,512	3,141,360					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

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.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
715.5 ACSR	16,790	210,756	227,546					1
715.5 ACSR	13,616	529,756	543,372					2
397.5 ACSR	395,696	3,443,681	3,839,377					3
715.5 ACSR	343,955	2,142,718	2,486,673					4
795 ACSR								5
715.5 ACSR	14,697	718,864	733,561					6
795 AAC		49,642	49,642					7
795 AAC	489,037	2,165,954	2,654,991					8
1272 ACSR	935,810	3,503,157	4,438,967					9
1272 ACSR	34,687	838,605	873,292					10
715.5 ACSR	179,817	3,270,853	3,450,670					11
795 AAC	43,035	434,341	477,376					12
1272 ACSR	140,412	2,577,075	2,717,487					13
1272 ACSR								14
795 ACSR	134,471	1,405,436	1,539,907					15
715.5 ACSR	2,473,833	19,385,962	21,859,795					16
715.5 ACSR								17
715.5 ACSR								18
715.5 ACSR								19
715.5 ACSR								20
1272 ACSR	78,579	2,259,301	2,337,880					21
	40,580		40,580					22
715.5 ACSR	331,539	4,682,879	5,014,418					23
								24
1272 ACSR	272,231	2,141,218	2,413,449					25
795 ACSR								26
795 ACSR								27
795 ACSR		351,497	351,497					28
1272 ACSR	690,611	6,015,350	6,705,961					29
715.5 ACSR	1,174	212,777	213,951					30
1272 ACSR	190	4,584	4,774					31
1272 ACSR								32
795 ACSR								33
795 ACSR								34
795 ACSR		-16,973	-16,973					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	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	04/15/2015	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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		60,659	60,659					1
250 COPPER	58	63,264	63,322					2
715.5 ACSR		76,560	76,560					3
397.5 ACSR		4,406	4,406					4
715.5 ACSR	1,074	622,115	623,189					5
397.5 ACSR	6,332	2,563,423	2,569,755					6
715.5 ACSR	86,651	2,429,399	2,516,050					7
715.5 ACSR								8
								9
715.5 ACSR	7	279,481	279,488					10
715.5 ACSR	5,620	997,718	1,003,338					11
715.5 ACSR	2,814	183,606	186,420					12
397.5 ACSR	12,885	261,511	274,396					13
								14
								15
								16
397.5 ACSR	1,978	63,404	65,382					17
								18
								19
VARIOUS	1,653,396	62,432,378	64,085,774					20
VARIOUS								21
								22
								23
VARIOUS	194,536	17,471,193	17,665,729					24
				7,400,901	3,369,518	3,284,850	14,055,269	25
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

Schedule Page: 422 Line No.: 9 Column: a

Lines 808 amd 809 are not Idaho Power Company they are the Company portion of investment into the Populus Station Lines

Schedule Page: 422 Line No.: 10 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

Schedule Page: 422 Line No.: 11 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

Schedule Page: 422 Line No.: 12 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Bowmont	Happy Valley	8.64	S Pole	17.70	1	1
2							
3							
4							
5							
6							
7							
8							
9							
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39							
40							
41							
42							
43							
44	TOTAL		8.64		17.70	1	1

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	ACSR	TVS	138	690,611	3,384,477	2,630,873		6,705,961	1
									2
									3
									4
									5
									6
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									38
									39
									40
									41
									42
									43
				690,611	3,384,477	2,630,873		6,705,961	44

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.09	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.47
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
10	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	13.00	
14	Blackfoot	transmission	161.00	46.00	12.47
15	Blackfoot	distribution	161.00	138.00	12.98
16	Bliss - attended	transmission	138.00	13.80	
17	Blue Gulch	distribution	138.00	35.00	
18	Boise Bench - attended	transmission	230.00	138.00	13.20
19	Boise Bench - attended	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	138.00	69.00	12.98
21	Boise Bench - attended	transmission	230.00	138.00	13.80
22	Boise	distribution	138.00	13.00	
23	Borah	transmission	345.00	230.00	13.80
24	Bowmont	distribution	69.00	46.00	6.90
25	Bowmont	distribution	138.00	35.00	
26	Bowmont	transmission	138.00	69.00	12.98
27	Bowmont	transmission	138.00	69.00	12.47
28	Bowmont	transmission	230.00	138.00	13.80
29	Brady	transmission	230.00	138.00	13.80
30	Brady	transmission	138.00	46.00	12.47
31	Brady	distribution	69.00	13.00	
32	Brownlee - attended	transmission	230.00	13.80	
33	Bruneau Bridge	distribution	138.00	35.00	
34	Bruneau Bridge	distribution	138.00	36.20	
35	Buckhorn	distribution	69.00	35.00	
36	Bucyrus	distribution	46.00	7.20	
37	Buhl	distribution	46.00	13.00	
38	Burley Rural	distribution	69.00	13.00	
39	Butler	distribution	138.00	13.09	
40	Caldwell	distribution	138.00	13.00	

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Caldwell	transmission	230.00	138.00	
2	Caldwell	distribution	138.00	13.09	
3	Caldwell	transmission	138.00	69.00	12.47
4	Caldwell	transmission	230.00	138.00	12.47
5	Caldwell	distribution	13.00	4.16	
6	Canyon Creek	distribution	138.00	35.00	
7	Canyon Creek	transmission	138.00	69.00	12.98
8	Cascade Power Plant - attended	transmission	69.00	4.60	
9	Cascade	distribution	69.00	13.10	
10	Cascade	distribution	25.00		
11	Chestnut	distribution	138.00	13.00	
12	Clear Lake - attended	transmission	46.00	2.40	
13	Cliff	transmission	138.00	46.00	12.50
14	Cliff	transmission	138.00	46.00	12.95
15	Cloverdale	distribution	138.00	13.00	
16	Dale	distribution	46.00	4.60	
17	Dale	distribution	46.00	13.00	
18	Dale	distribution	69.00	13.00	
19	Dale	distribution	138.00	36.20	
20	Dale	transmission	138.00	46.00	12.47
21	Danskin- attended	transmission	230.00	18.00	
22	Danskin- attended	transmission	230.00	138.00	13.80
23	Danskin- attended	distribution	18.00	4.16	
24	Danskin- attended	transmission	138.00	12.00	
25	Danskin- attended	distribution	35.00	13.80	
26	Don	distribution	138.00	7.60	
27	Don	distribution	138.00	13.20	
28	Don	distribution	138.00	13.00	
29	Don	distribution	14.00		
30	DRAM	distribution	138.00	13.09	
31	DRAM	transmission	230.00	138.00	13.80
32	DRAM	distribution	138.00	12.47	
33	Duffin	distribution	138.00	35.00	
34	Eagle	distribution	138.00	13.09	
35	Eastgate	distribution	138.00		
36	Eastgate	distribution	138.00	13.00	
37	Eckert	distribution	138.00	36.20	
38	Eden	distribution	138.00	36.20	
39	Eden	transmission	138.00	46.00	12.98
40	Elkhorn	distribution	138.00	12.47	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Elkhorn	distribution	138.00	13.00	
2	Elmore	distribution	138.00	35.00	
3	Elmore	transmission	138.00	69.00	12.50
4	Elmore	transmission	138.00	69.00	12.98
5	Emmett	distribution	138.00		
6	Emmett	transmission	138.00	69.00	12.47
7	Falls	distribution	46.00	13.00	
8	Falls	distribution	46.00		
9	Filer	distribution	46.00	13.00	
10	Flat Top	distribution	46.00	13.00	
11	Flying H	distribution	69.00	2.40	
12	Fort Hall	distribution	46.00	13.00	
13	Fossil Gulch	distribution	138.00	35.00	
14	Fremont	transmission	138.00	46.00	12.50
15	Gary	distribution	138.00	13.09	
16	Gary	distribution	138.00	13.00	
17	Gem	distribution	69.00	13.00	
18	Gem	distribution	69.00		
19	Goodng Rural	distribution	46.00	13.00	
20	Golden Valley	distribution	69.00	13.00	
21	Gowen Substation	distribution	138.00	35.00	
22	Grindstone	distribution	35.00		
23	Grove	distribution	138.00	13.09	
24	Grove	distribution	138.00	13.00	
25	Hagerman	distribution	46.00	13.00	
26	Hagerman	distribution	69.00	13.00	
27	Hailey	distribution	138.00	13.00	
28	Happy Valley	distribution	138.00	13.09	
29	Haven	distribution	138.00	35.00	
30	Haven	transmission	138.00	46.00	
31	Hemingway	transmission	500.00	230.00	34.50
32	Hewlett Packard	distribution	138.00	13.00	
33	Hidden Springs	distribution	138.00	13.00	
34	Highland	distribution	138.00	13.00	
35	Hill	distribution	138.00	13.00	
36	Hillsdale	distribution	138.00		
37	Hoku	distribution	138.00	13.80	
38	Homedale	distribution	69.00	13.00	
39	Horse Flat	transmission	230.00	138.00	13.80
40	Horseshoe Bend	distribution	35.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Horseshoe Bend	distribution	69.00	36.20	
2	Horseshoe Bend	distribution	69.00	25.00	
3	Huston	distribution	69.00	13.00	
4	Hulen	distribution	46.00	13.00	
5	Hunt	transmission	230.00	138.00	13.80
6	Hydra	distribution	138.00	36.20	
7	Island	distribution	69.00	13.00	
8	Jerome	distribution	138.00	13.00	
9	Jerome	distribution	138.00	13.09	
10	Julion Clawson	distribution	138.00	35.00	
11	Joplin	distribution	138.00	13.00	
12	Joplin	distribution	138.00	35.00	
13	Justice	transmission	230.00	138.00	13.80
14	Karcher	distribution	138.00	13.00	
15	Kenyon	distribution	69.00	13.00	
16	Ketchum	distribution	138.00	13.00	
17	Kimberly	distribution	138.00	13.00	
18	Kinport	transmission	161.00	46.00	13.20
19	Kinport	transmission	230.00	138.00	12.47
20	Kinport	transmission	230.00	138.00	13.80
21	Kinport	transmission	345.00	230.00	13.80
22	Kramer	distribution	138.00	35.00	
23	Kramer	distribution	138.00	36.20	
24	Kuna	distribution	138.00	13.00	
25	Lake	distribution	69.00	13.00	
26	Lake Fork	distribution	138.00	36.20	
27	Lake Fork	transmission	138.00	69.00	12.50
28	Lamb	distribution	138.00	13.00	
29	Langley Gulch- attended	transmission	230.00	138.00	13.80
30	Langley Gulch- attended	transmission	230.00		
31	Langley Gulch- attended	distribution		4.16	
32	Langley Gulch- attended	distribution	13.00	4.16	
33	Lansing	distribution	69.00	13.00	
34	Lincoln	distribution	138.00	13.09	
35	Linden	distribution	138.00	13.00	
36	Locust	distribution	138.00	36.20	
37	Locust	transmission	230.00	138.00	13.80
38	Lower Malad - attended	transmission	138.00	7.20	
39	Lower Salmon - attended	transmission	138.00	13.80	
40	Map Rock	distribution	69.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	McCall	distribution	13.00	13.09	
2	McCall	distribution	138.00	36.20	
3	Meridian	distribution	138.00	13.00	
4	Micron	distribution	138.00	13.09	
5	Micron	distribution	138.00	13.00	
6	Midpoint	transmission	230.00	138.00	13.80
7	Midpoint	transmission	345.00	230.00	13.80
8	Midpoint	transmission	500.00	345.00	
9	Midrose	distribution	138.00	13.09	
10	Milner	transmission	138.00	69.00	12.47
11	Milner	distribution	69.00	46.00	6.90
12	Milner	distribution	138.00	35.00	
13	Milner PP - attended	transmission	138.00	13.80	
14	Moonstone	distribution	138.00	35.00	
15	Mora	distribution	138.00	35.00	
16	Mora	distribution	138.00	36.20	
17	Moreland	distribution	35.00	13.00	
18	Moreland	distribution	46.00	13.00	
19	Moreland	distribution	46.00	35.00	12.47
20	Mountain Home	distribution	69.00	13.00	
21	Mountain Home Air Force Base	distribution	69.00	13.00	
22	Mountain Home Air Force Base	distribution	138.00	13.00	
23	Nampa	transmission	230.00	138.00	13.80
24	Nampa	distribution	138.00	13.00	
25	New Meadows	distribution	138.00	36.20	
26	New Plymouth	distribution	69.00	13.00	
27	Notch Butte	distribution	138.00	13.09	
28	Orchard	distribution	69.00	36.20	
29	Orchard	distribution	69.00	35.00	12.47
30	Parma	distribution	69.00	13.00	
31	Parma	distribution	69.00	35.00	
32	Paul	distribution	138.00	35.00	
33	Payette	distribution	138.00	13.00	
34	Pingree	transmission	138.00	46.00	12.50
35	Pingree	distribution	138.00	35.00	
36	Pleasant Valley	distribution	138.00	35.00	
37	Pocatello	distribution	46.00	13.00	
38	Poleline	distribution	138.00	13.09	
39	Populus	transmission	345.00		
40	Portneuf	distribution	138.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Portneuf	distribution	46.00	35.00	
2	Rockford	distribution	46.00	13.00	
3	Russett	distribution	138.00	13.00	
4	Sailor Creek	distribution	138.00	2.40	
5	Sailor Creek	distribution	138.00	35.00	
6	Salmon	distribution	69.00	13.00	
7	Salmon	distribution	69.00	34.50	12.47
8	Salmon	distribution	69.00		12.47
9	Salmon	transmission	13.00	2.40	
10	Shoshone	distribution	46.00	13.00	
11	Shoshone	distribution	46.00	7.20	
12	Shoshone Falls - attended	transmission	46.00	2.30	
13	Shoshone Falls - attended	transmission	46.00	6.60	
14	Silver	distribution	138.00	35.00	
15	Simplot	distribution	138.00	13.00	
16	Sinker Creek	distribution	138.00	35.00	
17	Siphon	distribution	138.00	35.00	
18	South Park	distribution	46.00	13.00	
19	Star	distribution	138.00	13.09	
20	Starkey	transmission	138.00	69.00	12.47
21	State	distribution	69.00	13.00	
22	Stoddard	distribution	138.00	13.00	
23	Strike Power Plant - attended	transmission	138.00	13.80	
24	Sugar	distribution	138.00	35.00	
25	Swan Falls - attended	transmission	138.00	6.90	
26	Taber	distribution	46.00	13.00	
27	Ten Mile	distribution	138.00	13.09	
28	Terry	distribution	138.00	13.09	
29	Terry	distribution	138.00	13.00	
30	Thousand Springs - attended	transmission	46.00	7.20	
31	Thousand Springs - attended	transmission	7.00	2.40	
32	Toponis	distribution	138.00	33.00	
33	Twin Falls	distribution	138.00	13.09	
34	Twin Falls	transmission	138.00	46.00	12.98
35	Twin Falls PP - attended	transmission	138.00	7.20	
36	Twin Falls PP - attended	transmission	138.00	13.20	
37	Upper Malad - attended	transmission	45.00	7.20	
38	Upper Salmon- attended	transmission	138.00	7.20	
39	Ustick	distribution	138.00	13.00	
40	Vallivue	distribution	138.00	13.09	

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Ontario	transmission	230.00	138.00	13.80
2	Ontario	transmission	138.00	69.00	12.98
3	Ontario	transmission	138.00	69.00	13.09
4	Ore-Ida	distribution	69.00	13.00	
5	Oxbow - attended	transmission	138.00	69.00	13.00
6	Oxbow - attended	transmission	230.00	13.80	
7	Oxbow - attended	transmission	230.00	138.00	13.80
8	Quartz	transmission	138.00	69.00	12.50
9	Quartz	transmission	230.00	138.00	12.98
10	Quartz	transmission	138.00	69.00	12.98
11	Vale	distribution	69.00	13.00	
12					
13	Wyoming:				
14	Jim Bridger - attended	transmission	345.00	230.00	34.50
15					
16					
17					
18					
19					
20	Transformers-distribution substations under 10,000				
21	KVA 83 unattended.				
22					
23					
24					
25					
26					
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28					
29					
30					
31					
32					
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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
50	3	1				14
80	1					15
69	3					16
15	1					17
254	2					18
42	2					19
75	3					20
240	2					21
67	3					22
450	3	1				23
8	3					24
18	1					25
25	1					26
25	1					27
180	1					28
312	3					29
		1				30
		1				31
721	5	1				32
18	1					33
24	1					34
20	1					35
6	1	1				36
20	2					37
12	1					38
48	2					39
15	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
120	1					1
24	1					2
75	3					3
120	1					4
		1				5
15	1					6
15	1					7
12	1					8
15	2					9
4	1					10
48	2					11
4	1					12
12	2	1				13
4	1					14
48	2					15
		1				16
		6				17
		1				18
27	1					19
25	1					20
140	1					21
180	1					22
6	1					23
96	2					24
5	1					25
		1				26
108	6	3				27
26	1	1				28
80	6					29
118	7					30
160	2					31
17	1					32
36	2					33
38	2					34
24	1					35
18	1					36
18	1					37
24	1					38
15	1					39
8	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
8	1					1
17	1					2
15	1					3
15	1					4
24	1					5
25	1					6
8	1					7
10	1					8
10	1					9
13	2					10
15	2					11
10	1	1				12
15	1					13
50	3	1				14
20	1					15
17	1					16
8	1					17
10	1					18
15	2					19
10	1	1				20
24	1					21
10	2					22
48	2					23
24	1					24
10	1					25
5	1					26
20	1					27
18	1					28
12	1					29
25	1					30
600	3	1				31
20	1					32
8	1					33
18	1					34
39	2					35
24	1					36
		2				37
22	2					38
100	1					39
5	1					40

SUBSTATIONS (Continued)

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

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

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
12	1					1
18	1					2
36	2					3
24	2					4
24	2					5
120	1					6
840	2	1				7
750	3					8
24	1					9
75	3	1				10
8	3	1				11
29	2					12
36	1					13
12	1					14
15	1					15
24	1					16
6	1					17
8	1					18
6	3	1				19
15	1					20
		1				21
18	1					22
180	1					23
50	3					24
12	1					25
10	1					26
10	1					27
6	1					28
10	3					29
10	1					30
12	1					31
36	2					32
23	3					33
50	3					34
22	2					35
42	2					36
36	2					37
18	1					38
						39
18	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.
		1				1
14	2					2
18	1					3
15	2					4
15	1					5
10	1	3				6
10	3					7
		2				8
5	2					9
10	1					10
2	3					11
3	1					12
10	1					13
12	1					14
30	2					15
12	1					16
33	2					17
10	1					18
18	1					19
18	1					20
33	2					21
15	1					22
83	3					23
20	2					24
18	1					25
5	1					26
24	1					27
12	1					28
30	2					29
8	1					30
		1				31
18	1					32
44	2					33
33	2					34
9	1					35
72	1					36
8	1					37
36	4					38
44	2					39
18	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	1					1
18	1					2
12	1	1				3
20	2					4
25	1					5
10	1					6
18	1					7
36	2					8
20	1					9
24	1					10
						11
						12
						13
						14
						15
24	3	1				16
						17
						18
	1					19
	1					20
	1					21
			Line Reactor	1	48	22
			Line Reactor	1	35	23
			Line Reactor	1	35	24
			Line Reactor	1	35	25
			Line Reactor	1	35	26
20	3	1				27
						28
						29
685	3					30
55	1					31
55	1					32
12	1					33
333	2	1				34
1	1					35
40	1					36
8	3	1				37
20	2					38
38	2					39
25	1	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	04/15/2015	End of 2014/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
240	2					1
50	2					2
		1				3
15	1					4
10	3	1				5
244	2					6
100	1					7
15	1					8
100	3	1				9
15	1					10
10	1					11
						12
						13
703	7					14
						15
						16
						17
						18
						19
						20
334						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.2 Line No.: 31 Column: a

PacifiCorp has a 59% interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway Station.

Schedule Page: 426.4 Line No.: 39 Column: a

Idaho Power has a 20.8% interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station.

Schedule Page: 426.6 Line No.: 19 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 20 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 21 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 22 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 23 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.: 24 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.: 25 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 26 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 30 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.: 31 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.: 32 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.7 Line No.: 14 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Managerial Expenses	IDACORP, INC.	417420	951,135
22			922000	74,887
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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

PUC FORM 559 (11000) (04-07)

STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)..	2	$ 58,072,640	$ 57,053,369
3	Operating Expenses			
4	Operation Expenses (401)..	8-11	35,670,311	35,392,549
5	Maintenance Expenses (402)...	8-11	3,330,826	3,313,642
6	Depreciation Expense (403)...	12	5,440,231	5,290,169
7	Amort. & Depl. of Utility Plant (404-405)..	12	305,974	324,193
8	Amort. of Utility Plant Acq. Adj. (406)..	12	-	-
9	Amort. of Property Losses, Unrecovered Plant and Regulatory.............. Study Costs (407-411)	12	(7,943)	(1,723)
10	Accretion Expense (411)..	12	13,462	14,090
11	Amort. of Conversion Expenses (407)..	12		
12	Taxes Other Than Income Taxes (408.1)...	13	2,178,512	2,186,489
13	Regulatory Debits/Credits..	14	73,651	56,176
14	Income Taxes - Federal (409.1)..	14	(358,505)	(85,708)
15	- Other (409.1)...	15	284,353	137,781
16	Provision for Deferred Inc. Taxes (410.1)...	16-23	6,432,277	5,072,835
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)......................	16-23	(5,661,366)	(2,894,629)
18	Investment Tax Credit Adj. - Net (411.4)..	24	1,774	(33,121)
19	(Less) Gains from Disp. of Utility Plant (411.6).....................................			
20	Losses from Disp. of Utility Plant (411.7)..			
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20).................		47,703,558	48,772,743
22	Net Utility Operating Income (Total of line 2 less 20)..........................		$ 10,369,082	$ 8,280,627

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote).
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	(a)	OPERATING REVENUES: Amount for Current Year (b)	OPERATING REVENUES: Amount for Previous Year (c)	MEGAWATT HOURS SOLD: Amount for Current Year (d)	MEGAWATT HOURS SOLD: Amount for Previous Year (e)	AVG NO OF CUSTOMERS PER MONTH: Number for Current Year (f)	AVG NO OF CUSTOMERS PER MONTH: Number for Previous Year (g)	Line No.
1	Sales of Electricity							1
2	(440) Residential Sales	$ 18,244,476	$ 19,397,656	181,003	197,839	13,347	13,350	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)	17,394,273	17,236,522	202,156	205,430	5,176	5,105	4
5	Large (or Industrial) (See Instr. 4) (2)	15,072,302	14,555,504	246,144	244,011	6	6	5
6	(444) Public Street and Highway Lighting	156,911	141,960	987	896	32	29	6
7	(445) Other Sales to Public Authorities							7
8	(446) Sales to Railroads and Railways							8
9	(448) Interdepartmental Sales							9
10	TOTAL Sales to Ultimate Consumers	50,867,962*	51,331,642*	630,290 **	648,176	18,561	18,490	10
11	(447) Sales for Resale - Opportunity Non-Firm	3,423,845	2,403,572	98,521	74,276			11
12	TOTAL Sales of Electricity	54,291,807	53,735,214	728,811	722,452	18,561	18,490	12
13	(Less) (449.1) Provision for Rate Refunds	15,205	(15,146)					13
14	TOTAL Revenue Net of Provision for Refunds	54,307,012	53,720,068					
15	Other Operating Revenues							
16	(450) Forfeited Discounts							
17	(451) Miscellaneous Service Revenues	83,536	74,976					
18	(453) Sales of Water and Water Power							
19	(454) Rent from Electric Property	1,119,257	1,150,868					
20	(455) Interdepartmental Rents							
21	(456) Other Electric Revenues	2,562,835	2,107,458					
22								
23								
24								
25	TOTAL Other Operating Revenues	3,765,628	3,333,302					
26	TOTAL Electric Operating Revenues	$ 58,072,640	$ 57,053,370					

* Includes $267,967 unbilled revenues.

** Includes 6,331 MWH relating to unbilled revenues.

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

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

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	183,964	$ 18,539,994	13,347	13,783	10.08
3	03 - Residential-Mastered Metered					
4	05 - Residential - TOD					
5	15 - Dusk to Dawn customer Lighting	185	51,798			28.00
6	**Residential - Billed**	**184,149**	**18,591,792**	**13,347**	**13,797**	**10.10**
7	Residential - Unbilled	(3,146)	(255,247)			8.11
8	Bridger Depr & Boardman Decomm		(92,069)			
9	**Total 440**	**181,003**	**18,244,476**	**13,347**	**13,561**	**10.08**
10						
11	442 - Commercial and Industrial Sales:					
12	07 - General Service	16,922	1,813,367	2,415	7,007	10.72
13	09P - General Service	16,701	1,172,115	6	2,783,500	7.02
14	09S - General Service	114,430	9,116,320	929		
15	09T - General Service	2,580	180,291	1		
16	15 - Dusk to dawn customer lighting	265	59,800			22.57
17	19P - Uniform rate contracts	146,072	9,245,979	5	29,214,400	6.33
18	19S - Uniform rate contracts					
19	19T - Uniform rate contracts	89,686	5,416,896	1		
20	24S - Irrigation and soil drainage pumpin	52,168	5,146,807	1,823	28,617	9.87
21	40 - General Service	7	692	2	3,500	9.89
22	**Commercial & Industrial - Billed**	**438,831**	**32,152,267**	**5,182**	**84,684**	**7.33**
23	Commercial & Industrial - Unbilled	9,469	521,193			5.50
24	Bridger Depr & Boardman Decomm		(206,885)			
25	**Total 442**	**448,300**	**32,466,575**	**5,182**	**86,511**	**7.24**
26						
27						
28	444 - Public Street and Highway Lighting:					
29	40 - General Service					
30	41 - Municipal street lighting	958	153,310	25	38,320	16.00
31	42 - Municipal traffic control signal lightin	21	1,972	7	3,000	9.39
32	**Public Street & Highway lighting billed**	**979**	**155,282**	**32**	**30,594**	**15.86**
33	Public St & Highway lighting-unbilled	8	2,021			
34	Bridger Depr & Boardman Decomm		(392)			
35	**Total 444**	**987**	**156,911**	**32**	**30,844**	**15.90**
36						
37						
38						
39						
40						
41	Total Billed	623,959	50,599,995	18,561	33,617	8.11
42	Total Unbilled Rev. (See Instr. 6)	6,331	267,967			
43	TOTAL	630,290	50,867,962	18,561	33,617	8.11

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

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

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

Line No.	Sales To (a)	Stat. Class. (b)	Export Across State Lines (c)	FERC Rate Sch. No. (d)	Point of Delivery (State or County) (e)	Station Owner-Ship (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1									
2									
3	Various Utilities								
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

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

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

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

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

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
							1
							2
				3,423,845		$ 3,423,845	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
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							27
							28
							29

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

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

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

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

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

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Rental	$ 456,642
22			
23	"	Transformer Rentals - Dist	679
24			
25	"	Line Rentals	90,556
26			
27	"	Cogeneration	45,407
28			
29	"	Pole Attachments	118,413
30			
31	"	Facilities Charges	381,187
32			
33	"	Other Rentals	26,374
34			
35	"	Miscellaneous	-
36			
37	"		
38	Total Account 454		$ 1,119,257

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

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

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

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

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

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues	$ 83,536
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 296,189
11	Transmission - Point-to-Point and Other	665,328
12	Photovoltaic Station Service	8
13	DSM Rider Funds	1,597,741
14	Sierra Pacific Usage Charge	118
15	Antelope	3,153
16	Miscellaneous	297
17		
18		
19		
20	Total Account 456	$ 2,562,835
21		
22		
23		

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes. Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 58,670	$ 64,740
5	(501) Fuel	6,929,438	7,072,128
6	(502) Steam Expenses	387,854	390,099
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	70,971	76,826
10	(506) Miscellaneous Steam Power Expenses	409,061	402,195
11	(507) Rents	22,609	14,788
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	7,878,604	8,020,776
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	11,842	4,314
16	(511) Maintenance of Structures	30,185	27,079
17	(512) Maintenance of Boiler Plant	484,662	549,874
18	(513) Maintenance of Electric Plant	268,218	238,227
19	(514) Maintenance of Miscellaneous Steam Plant	247,447	192,800
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,042,355	1,012,295
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	8,920,958	9,033,071
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	243,622	256,767
45	(536) Water for Power	311,786	241,112
46	(537) Hydraulic Expenses	600,796	576,202
47	(538) Electric Expenses	65,794	61,353
48	(539) Miscellaneous Hydraulic Power Generation Expenses	244,301	206,146
49	(540) Rents	11,068	6,011
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,477,368	1,347,591

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 5,207	$ 3,558
54	(542) Maintenance of Structures	59,124	60,594
55	(543) Maintenance of Reservoirs, Dams, and Waterways	15,611	48,749
56	(544) Maintenance of Electric Plant	98,397	112,454
57	(545) Maintenance of Miscellaneous Hydraulic Plant	108,869	127,602
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	287,208	352,957
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,764,576	1,700,549
61	Operation		
62	(546) Operation Supervision and Engineering	34,684	57,776
63	(547) Fuel	1,999,727	2,391,765
64	(548) Generation Expenses	155,723	147,915
65	(549) Miscellaneous Other Power Generation Expenses	38,592	24,865
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,228,726	2,622,321
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	4
70	(552) Maintenance of Structures	16,112	12,791
71	(553) Maintenance of Generating and Electric Plant	3,764	5,689
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	59,297	52,387
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	79,173	70,871
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	2,307,899	2,693,192
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	10,516,280	9,479,493
77	(556) System Control and Load Dispatching	(53)	59,581
78	(557) Other Expenses	2,334,208	2,432,425
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	12,850,435	11,971,500
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	25,843,868	25,398,311
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	171,639	151,469
84	(561) Load Dispatching	114,812	121,980
85	(562) Station Expenses	104,957	102,232
86	(563) Overhead Line Expenses	28,595	31,180
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	269,830	248,742
89	(566) Miscellaneous Transmission Expenses	780	2,109
90	(567) Rents	140,275	124,126
91	TOTAL Operation (Enter Total of lines 83 thru 90)	830,890	781,837
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	7,238	13,760
94	(569) Maintenance of Structures	44,256	32,011
95	(570) Maintenance of Station Equipment	158,083	153,560
96	(571) Maintenance of Overhead Lines	136,661	152,765
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	68	26
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	346,307	352,121
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,177,196	1,133,959
102	Operation		
103	(580) Operation Supervision and Engineering	172,579	179,946

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes. Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 142,656	$ 143,636
106	(582) Station Expenses	40,668	45,099
107	(583) Overhead Line Expenses	230,739	228,407
108	(584) Underground Line Expenses	35,910	35,897
109	(585) Street Lighting and Signal System Expenses	3,503	3,407
110	(586) Meter Expenses	147,962	154,311
111	(587) Customer Installations Expenses	53,885	53,223
112	(588) Miscellaneous Distribution Expenses	247,970	248,856
113	(589) Rents	19,967	15,836
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,095,840	1,108,617
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	705	7,304
117	(591) Maintenance of Structures	-	-
118	(592) Maintenance of Station Equipment	136,125	125,168
119	(593) Maintenance of Overhead Lines	1,022,270	1,063,863
120	(594) Maintenance of Underground Lines	8,965	9,647
121	(595) Maintenance of Line Transformers	5,800	11,675
122	(596) Maintenance of Street Lighting and Signal Systems	24,223	24,567
123	(597) Maintenance of Meters	24,593	26,193
124	(598) Maintenance of Miscellaneous Distribution Plant	32,465	32,613
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,255,147	1,301,031
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,350,986	2,409,648
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	22,068	21,625
130	(902) Meter Reading Expenses	206,108	171,657
131	(903) Customer Records and Collection Expenses	600,300	513,028
132	(904) Uncollectible Accounts	398,936	318,829
133	(905) Miscellaneous Customer Accounts Expenses	5	13
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	1,227,417	1,025,153
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	32,177	17,732
138	(908) Customer Assistance Expenses	1,850,917	1,424,249
139	(909) Informational and Instructional Expenses	13,513	9,651
140	(910) Miscellaneous Customer Service and Informational Expenses	37,606	19,190
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	1,934,213	1,470,822
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	3,313,235	3,046,421
152	(921) Office Supplies and Expenses	789,641	775,926
153	(922) Administrative Expenses Transferred-Credit	(1,234,364)	(1,184,437)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 213,073	$ 232,274
156	(924) Property Insurance	145,759	153,195
157	(925) Injuries and Damages	277,374	250,890
158	(926) Employee Pensions and Benefits	2,183,514	3,186,046
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	215,826	374,351
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	20,521	21,895
163	(930.2) Miscellaneous General Expenses	222,233	187,092
164	(931) Rents	8	279
165	TOTAL Operation (Enter Total of lines 151 thru 164)	6,146,820	7,043,932
166	Maintenance		
167	(935) Maintenance of General Plant	320,637	224,366
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	6,467,457	7,268,298
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 39,001,137	$ 38,706,191

SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON

Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 7,878,604	$ 1,042,355	$ 8,920,958
173	Nuclear power			
174	Hydraulic - Conventional	1,477,368	287,208	1,764,576
175	Hydraulic - Pumped Storage			
176	Other power	2,228,726	79,173	2,307,899
	Other Power Supply Expenses	12,850,435	-	12,850,435
177	Total Power Production Expenses	24,435,132	1,408,736	25,843,868
178	Transmission Expenses	830,890	346,307	1,177,196
179	Distribution Expenses	1,095,840	1,255,147	2,350,986
180	Customer Accounts Expenses	1,227,417	-	1,227,417
181	Customer Service and Informational Expenses	1,934,213	-	1,934,213
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	6,146,820	320,637	6,467,457
184	Total Electric Operation and Maintenance Expenses	$ 35,670,311	$ 3,330,826	$ 39,001,137

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 305,974		$ 305,974
2	Steam Production Plant	1,044,922	-		1,044,922
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	598,969	-		598,969
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	732,597	-		732,597
7	Transmission Plant	857,820	-		857,820
8	Distribution Plant	1,796,175	-		1,796,175
9	General Plant	401,161	-		401,161
10	Depreciation on Disallowed Costs	(12,820)	-		(12,820)
11	Boardman ARO Depreciation	21,406			21,406
12	ARO Accretion	13,462			13,462
13	TOTAL	$ 5,453,693	$ 305,974		$ 5,759,667

B. OTHER AMORTIZATION

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

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			$ -
Account 411			
411.6			$ -
411.7			-
411.8			(7,943)
			$ (7,943)

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

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 635,965
3	FUTA	4,159
4	Less: Payroll Deduction and Loading	(671,978)
5	State Taxes:	
6	Ad Valorem	1,138,988
7	Licenses - Hydro Projects	209
8	Regulatory Commission Fees	186,899
9	Franchise Taxes	800,080
10	State Unemployment Taxes	31,853
11	Hydro Generation KWH Tax	52,336
12	Canada Sales Tax	0
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,178,512

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

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

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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 58,072,640
2	Operations and Maintenance Expenses	39,001,137
3	Taxes Other Than Income	2,178,512
4	Regulatory Debits/Credits	73,651
5	State Income (Excise) Tax	409,387
6	Interest	3,772,803
7	Federal Income Tax Depreciation	5,440,231
8	Other Line items to Derive Taxable Income	13,462
9	Amortization of Limited-Term Plant	298,031
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 6,885,425
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 2,409,899
30	FIN 48 Adjustment	-
31	Prior Years' Tax Adjustment	(451,742)
32	Total Federal Income Tax Before Other Adjustment	1,958,157
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,127,154
36	Income Tax Adjustments	(7,746,186)
37	Federal Tax on Other Tax Adj @ 35%	(2,316,661)
38		
39	Total Federal Income Tax	$ (358,505)

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

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

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

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 58,072,640
2	Operations and Maintenance Expenses	39,001,137
3	Taxes Other Than Income	2,178,512
4	Regulatory Debits/Credits	73,651
5	Interest	3,772,803
6	State Income (Excise) Tax Depreciation	5,440,231
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	298,031
	ARO Accretion Expense	13,462
10	Income Tax Adjustments	3,267,675
11	Allowance for AFUDC	(1,127,154)
12	IERCO Taxable Income	(485,830)
13		
14	State Tax Net Income	$ 5,640,122
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	409,387
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(125,034)
24		
25		
26	Total Oregon State Tax	$ 284,353

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		44,121	(436)
4	Other Operating (See Note 1)		2,911,118	(2,059,994)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 2,955,239	$ (2,060,430)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 2,955,239	$ (2,060,430)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		4,852	0
	Executive Deferred Compensation Short-Term		16,130	(7)
	Executive Deferred Compensation Long-Term		565	(113)
	SFAS 112 - Post Retirement Benefits		457	0
	Non-VEBA Pension and Benefits		4,992	0
	FAS 123R - Stock Based Compensation		40,795	(51,264)
	Provision for Rate Refunds		6,571	(53)
	Revenue Sharing		124,752	(131,255)
	Montana NOL		6,540	(2,289)
	Oregon NOL		21,597	(11,238)
	Federal NOL		1,629,259	(433,602)
	Valmy Union Pacific Contract		24,170	(17,284)
	Deferred Idaho ITC		9,780	(94,888)
	VEBA - Post Retiree Benefits		10,610	(38,043)
	Bridger Revenue Deferral		0	(5,254)
	AFUDC Hells Canyon Relicensing		0	(229,004)
	Reg Liability		107,071	(110,907)
	Reg Asset		883,278	(654,107)
	Boardman Decommission		0	(12,510)
	CSPP Co-Generator Overpayment		19,699	0
	Oregon Pension Expense		0	(11,908)
	Incentive Deferral - Profit Sharing not in rates		0	(213,012)
	M&E Reserve		0	(24,800)
	Asset Retirement Obligation (ARO)		0	(18,458)
	Total	$	$ 2,911,118	$ (2,059,994)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
42,088	(81,263)						6
							7
							8
$ 42,088	$ (81,263)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 42,088	$ (81,263)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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

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

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

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

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

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

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

4. Use separate pages as required.

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

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)

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

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 1,305,674	$ (695,841)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		1,305,674	(695,841)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 1,305,674	$ (695,841)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Line 2:			
Depr Federal Adj		1,211,406	(540,307)
Intangible Asset - Labor Deductions		128,012	-
N Valmy Partnership Capitalized Itmes		-	(3,267)
CIAC as Taxable Income		18,390	(144,357)
FERC Juris-S Georgia-Acct 282 Def only		-	-
Engineering Fees		0	(7,910)
Software Costs		(52,134)	-
Total		1,305,674	(695,841)

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

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

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

4. Use separate pages as required.

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

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		2,171,364	(2,905,095)
3				
4	Total Electric..		2,171,364	(2,905,095)
5				
6				
7	Other (See Note 2)...			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)..........		$ 2,171,364	$ (2,905,095)
11	Classification of Total:			
12	Federal Income Tax..			
13	State Income Tax..			
14	Local Income Tax...			
	Note 1:			
	Oregon PCAM..		0	(29,099)
	FERC Grid West Expense..		0	0
	PCA		278,845	(775,555)
	Conservation Programs..		143,540	(127,604)
	Oregon Excess Power Supply Costs.............................		269	(1,043)
	OATT Revenue Deficiency		0	(11,269)
	Emission Allowances..		408	(221)
	Fixed Cost Adjustment (FCA).......................................		92,285	(23,312)
	OPUC Grid West Loans…………………………..............		0	(232)
	Intervenor Funding Orders...		1,613	0
	Bonus Deferral...		459	0
	Reorganization Costs...		0	(3,777)
	Delivery Accruals..		438	(223)
	REC Sales..		14,458	(33,138)
	Pension Expense..		850,730	(905,112)
	LIDAR Surveys Deferral...		0	(714)
	Bennett Mtn Maintenance Deferral...............................		0	(1,226)
	Custom Efficiency Incentive Payment...........................		0	0
	Reg Liability...		110,907	(107,071)
	Reg Asset..		654,107	(883,278)
	Langley Revenue Deferral..		800	0
	Boardman Decommission...		22,503	(2,220)
	PS&I Costs - Coal & CHP Plants - Write Off................		0	0
	Total..		2,171,364	(2,905,095)
	Note 2:			
	Advance Coal Royalties..			
	Oregon Non-Operating Property Tax Adj......................			
	Unrealized Gain/Loss from Rabbi Trust........................			
	Total..			

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

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

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
0	0						2
							3
-	-		-		-		4
							5
							6
3,389	(2,865)						7
							8
							9
$ 3,389	$ (2,865)		$ -		$ -		10
							11
							12
							13
							14

0	0
1,015	0
1	(0)
2,373	(2,865)
3,389	(2,865)

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 129,993	411.4	$ (128,219)			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)........	$ 452,092,803	$ 452,092,803				
4	Property Under Capital Leases........						
5	Plant Purchased or Sold........						
6	Completed Construction not Classified........						
7	Experimental Plant Unclassified........						
8	TOTAL (Enter Total of lines 3 thru 7)........	$ 452,092,803	$ 452,092,803				
9	Leased to Others........						
10	Held for Future Use........	$ 89,977	$ 89,977				
11	Construction Work in Progress........	$ 40,508,061	$ 40,508,061				
12	Acquisition Adjustments........						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)........	$ 492,690,841	$ 492,690,841				
14	Accum. Prov. for Depr., Amort., & Depl........	**NOT AVAILABLE**					
15	Net Utility Plant (Enter Total of line 13 less 14)........	$ 492,690,841	$ 492,690,841				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation........	**NOT AVAILABLE**					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights........						
20	Amort. of Underground Storage Land and Land Rights........						
21	Amort. of Other Utility Plant........						
22	TOTAL In Service (Enter total of lines 18 thru 21)........						
23	Leased to Others						
24	Depreciation........						
25	Amortization and Depletion........						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)........						
27	Held for Future Use						
28	Depreciation........						
29	Amortization........						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)........						
31	Abandonment of Leases (Natural Gas)........						
32	Amort. of Plant Acquisition Adj........						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)........						

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	241,023					241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	242,253	0	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	14,291,124	147,575	(2,030,614)			12,408,085	(311)	9
10	(312) Boiler Plant Equipment	40,939,969	2,896,584	(269,694)			43,566,859	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,569,621	1,139				13,570,760	(314)	12
13	(315) Accessory Electric Equipment	4,597,670	64,192	(1,026)			4,660,836	(315)	13
14	(316) Misc. Power Plant Equipment	1,773,842	28,428	(121,652)			1,680,618	(316)	14
15	(317) Asset Retirement Costs for Steam Production	4,075,579	272,642				4,348,221	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	79,354,415	3,410,560	(2,422,986)	0	0	80,341,989		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	11,041,270	140,405				11,181,675	(330)	27
28	(331) Structures and Improvements	19,247,386	192,153				19,439,539	(331)	28
29	(332) Reservoirs, Dams, and Waterways	91,309,867	323,539				91,633,406	(332)	29
30	(333) Water Wheels, Turbines, and Generators	22,969,288	4,542	(4,326)			22,969,504	(333)	30
31	(334) Accessory Electric Equipment	11,967,861	657,803	(98,000)			12,527,664	(334)	31
32	(335) Misc. Power Plant Equipment	3,943,285	202,983				4,146,268	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105					1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0					0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	161,867,062	1,521,425	(102,326)		0	163,286,161		35

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plan								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	241,221,477	4,931,985	(2,525,312)	0	0	243,628,150		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,650,002	$ 7,359				4,657,361	(350)	48
49	(352) Structures and Improvements	6,745,890	(3,228)	(687)			6,741,975	(352)	49
50	(353) Station Equipment	32,946,296	1,061,817	(7,974)			34,000,139	(353)	50
51	(354) Towers and Fixtures	14,836,778	697,024	(15,378)			15,518,424	(354)	51
52	(355) Poles and Fixtures	21,202,322	2,191,529	(144,029)			23,249,822	(355)	52
53	(356) Overhead Conductors and Devices	18,624,354	1,381,514	(178,561)			19,827,307	(356)	53
54	(357) Underground Conduit	0					0	(357)	54
55	(358) Underground Conductors and Devices	0					0	(358)	55
56	(359) Roads and Trails	48,566					48,566	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	99,054,208	5,336,015	(346,629)	0	0	104,043,594		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	148,192	$ 1,044				149,236	(360)	60
61	(361) Structures and Improvements	1,221,060	267,191	(498)			1,487,753	(361)	61
62	(362) Station Equipment	7,440,583	(79,558)	(45,180)			7,315,845	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,990,703	556,437	(63,186)			18,483,954	(364)	64
65	(365) Overhead Conductors and Devices	8,552,804	152,937	(56,667)			8,649,074	(365)	65
66	(366) Underground Conduit	672,470	(9,010)	(363)			663,097	(366)	66
67	(367) Underground Conductors and Devices	3,119,614	390	(852)			3,119,152	(367)	67
68	(368) Line Transformers	42,830,371	1,925,086	(84,293)			44,671,164	(368)	68
69	(369) Services	2,850,410	25,587	(12,521)			2,863,476	(369)	69
70	(370) Meters	6,638,862	660,707	(26,627)			7,272,942	(370)	70
71	(371) Installations on Customer Premises	229,137	6,385	(9,505)			226,017	(371)	71
72	(372) Leased Property on Customer Premises	0					0	(372)	72
73	(373) Street Lighting and Signal Systems	208,552	(506)	(2,848)			205,198	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0					0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	91,902,758	3,506,690	(302,540)	0	0	95,106,908		75

ELECTRIC PLANT IN SERVICE

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

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

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

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	495,898					495,898	(390)	78
79	(391) Office Furniture and Equipment	145,026	32,043	(5,598)			171,471	(391)	79
80	(392) Transportation Equipment	2,534,582	87,309	(71,248)			2,550,643	(392)	80
81	(393) Stores Equipment						0	(393)	81
82	(394) Tools, Shop and Garage Equipment	5,381					5,381	(394)	82
83	(395) Laboratory Equipment	80,435		(18,413)			62,022	(395)	83
84	(396) Power Operated Equipment	1,561,115	15,931				1,577,046	(396)	84
85	(397) Communication Equipment	3,778,306	510,383	(106,672)			4,182,017	(397)	85
86	(398) Miscellaneous Equipment	19,177					19,177	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	8,628,163	645,666	(201,931)	0	0	9,071,897		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	8,628,163	645,666	(201,931)	0	0	9,071,897		91
92	TOTAL (Accounts 101 and 106)	441,048,860	14,420,356	(3,376,412)	0	0	452,092,803		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 441,048,860	$ 14,420,356	$ (3,376,412)	$	$	$ 452,092,803		96

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

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

NOTE

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

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

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

Section A. Balances and Changes During Year

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

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

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

MATERIALS AND SUPPLIES

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

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

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified).........	$ 224,112,935	$ 224,112,935				
4	Property Under Capital Leases.........						
5	Plant Purchased or Sold.........						
6	Completed Construction not Classified.........						
7	Experimental Plant Unclassified.........						
8	TOTAL (Enter Total of lines 3 thru 7).........	224,112,935	224,112,935				
9	Leased to Others.........						
10	Held for Future Use.........	$ 276,689	276,689				
11	Construction Work in Progress.........						
12	Acquisition Adjustments.........						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12).........	224,389,624	224,389,624				
14	Accum. Prov. for Depr., Amort., & Depl.........	$ 88,062,303	88,062,303				
15	Net Utility Plant (Enter Total of line 13 less 14).........	$ 136,327,321	$ 136,327,321				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation.........	$ 87,074,067	$ 87,074,067				
19	Amort and Depl of Producing Natural Gas land and land Rights.........						
20	Amort. of Underground Storage Land and Land Rights.........						
21	Amort. of Other Utility Plant.........	$ 988,237	988,237				
22	TOTAL In Service (Enter total of lines 18 thru 21).........	88,062,303	88,062,303				
23	Leased to Others						
24	Depreciation.........						
25	Amortization and Depletion.........						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation.........						
29	Amortization.........						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas).........						
32	Amort. of Plant Acquisition Adj.........						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32).....	$ 88,062,303	$ 88,062,303				

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization....	$ 244					$ 244	(301)	2
3	(302) Franchises and Consents....	1,252,078					1,248,518	(302)	3
4	(303) Miscellaneous Intangible Plant....	1,367,084					1,265,193	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)....	$ 2,619,406					$ 2,513,955		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights....							(310)	8
9	(311) Structures and Improvements....							(311)	9
10	(312) Boiler Plant Equipment....							(312)	10
11	(313) Engines and Engine Driven Generators....							(313)	11
12	(314) Turbogenerator Units....							(314)	12
13	(315) Accessory Electric Equipment....							(315)	13
14	(316) Misc. Power Plant Equipment....							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment....							(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)....	$ 41,056,036					$ 42,286,985		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights....							(320)	18
19	(321) Structures and Improvements....							(321)	19
20	(322) Reactor Plant Equipment....							(322)	20
21	(323) Turbogenerator Units....							(323)	21
22	(324) Accessory Electric Equipment....							(324)	22
23	(325) Misc. Power Plant Equipment....							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production....							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)....								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights....							(330)	27
28	(331) Structures and Improvements....							(331)	28
29	(332) Reservoirs, Dams, and Waterways....							(332)	29
30	(333) Water Wheels, Turbines, and Generators....							(333)	30

ELECTRIC PLANT IN SERVICE

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

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

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

ELECTRIC PLANT IN SERVICE (Continued)

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 34)	$ 31,386,956					$ 32,564,876		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights							(340)	37
38	(341) Structures and Improvements							(341)	38
39	(342) Fuel Holders, Products and Accessories							(342)	39
40	(343) Prime Movers							(343)	40
41	(344) Generators							(344)	41
42	(345) Accessory Electric Equipment							(345)	42
43	(346) Misc. Power Plant Equipment							(346)	43
44	(347) Asset Retirement Costs for Other Production							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 23,601,196					$ 23,615,848		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	96,044,188					98,467,709		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,532,053					1,540,411	(350)	48
49	(352) Structures and Improvements	2,975,567					3,100,448	(352)	49
50	(353) Station Equipment	16,543,436					17,069,192	(353)	50
51	(354) Towers and Fixtures	6,877,672					7,167,489	(354)	51
52	(355) Poles and Fixtures	5,513,805					6,109,374	(355)	52
53	(356) Overhead Conductors and Devices	8,009,224					8,392,324	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	16,568					16,632	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	$ 41,468,324					$ 43,395,870		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	135,100					123,895	(360)	60
61	(361) Structures and Improvements	1,134,552					1,600,539	(361)	61
62	(362) Station Equipment	6,453,594					6,960,940	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	17,990,702					18,483,952	(364)	64
65	(365) Overhead Conductors and Devices	8,552,804					8,649,074	(365)	65
66	(366) Underground Conduit	672,470					663,097	(366)	66
67	(367) Underground Conductors and Devices	3,119,614					3,119,152	(367)	67
68	(368) Line Transformers	19,204,415					19,367,860	(368)	68
69	(369) Services	2,850,412					2,863,478	(369)	69
70	(370) Meters	2,552,611					2,692,878	(370)	70
71	(371) Installations on Customer Premises	229,138					226,017	(371)	71

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises..........							(372)	72
73	(373) Street Lighting and Signal Systems..........	208,552					205,198	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant..........							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)..........	$ 63,103,964					$ 64,956,080		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights..........	708,271					707,961	(389)	77
78	(390) Structures and Improvements..........	4,397,457					4,570,892	(390)	78
79	(391) Office Furniture and Equipment..........	1,747,133					1,960,200	(391)	79
80	(392) Transportation Equipment..........	2,893,255					3,169,200	(392)	80
81	(393) Stores Equipment..........	81,541					82,691	(393)	81
82	(394) Tools, Shop, and Garage Equipment..........	307,448					323,468	(394)	82
83	(395) Laboratory Equipment..........	531,627					540,303	(395)	83
84	(396) Power Operated Equipment..........	546,861					595,204	(396)	84
85	(397) Communication Equipment..........	1,876,485					2,296,939	(397)	85
86	(398) Miscellaneous Equipment..........	245,072					238,162	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)..........	13,335,149					14,485,020		87
88	(399) Other Tangible Property *..........							(399)	88
89	(399.1) Asset Retirement Costs for General Plant..........							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)..........	13,335,149					14,485,020		90
91	TOTAL (Accounts 101 and 106)..........	216,571,031					223,818,635		91
92	(102) Electric Plant Purchased **..........								92
93	(Less) (102) Electric Plant Sold **..........								93
94	Asset Retirement Obligations (ARO)..........	449,138					294,300		94
95	TOTAL Electric Plant in Service..........	$ 217,020,169					$ 224,112,935		95

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

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

NOTE

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

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	5,440,231	5,440,231		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	5,440,231	5,440,231		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)	$ 5,440,231	$ 5,440,231		

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

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$ 22,908,067	$ 22,908,067		
19	Nuclear Production				
20	Hydraulic Production - Conventional	16,648,895	16,648,895		
21	Hydraulic Production - Pumped Storage				
22	Other Production	3,089,728	3,089,728		
23	Transmission	13,352,411	13,352,411		
24	Distribution	26,263,563	26,263,563		
25	General	4,557,356	4,557,356		
26	FAS 143 Adj &/or Disallowed Cost	254,046	254,046		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 87,074,067	$ 87,074,067		

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)........	$ 1,833,210	$ 2,447,942	
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)........	700,746	724,920	
8	Transmission Plant (Estimated)........	465,769	478,799	
9	Distribution Plant (Estimated)........	888,256	880,894	
10	Assigned to - Other........	54,464	64,844	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)........	2,109,235	2,149,457	
12	Merchandise (Account 155)........			
13	Other Materials and Supplies (Account 156)........			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)........			
15	Stores Expense Undistributed (Account 163)........	186,915	217,731	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)........	$ 4,129,360	$ 4,815,130	

ELECTRIC ENERGY ACCOUNT

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

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

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	91.45	Monday	6	9 AM	60 Min. Int	57,650
34	February	106.01	Thursday	6	8 AM	" " "	54,012
35	March	88.53	Wednesday	12	8 AM	" " "	48,411
36	April	67.13	Thursday	24	10 AM	" " "	40,445
37	May	89.32	Tuesday	27	7 PM	" " "	57,793
38	June	106.85	Monday	23	7 PM	" " "	60,890
39	July	110.35	Tuesday	8	6 PM	" " "	65,281
40	August	115.59	Friday	1	5 PM	" " "	64,117
41	September	95.24	Tuesday	16	6 PM	" " "	53,170
42	October	83.37	Tuesday	7	6 AM	" " "	52,755
43	November	119.03	Tuesday	18	8 AM	" " "	60,595
44	December	116.48	Wednesday	14	10 AM	" " "	65,872
45	TOTAL	1,189.35					680,991

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

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

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues......	$ 453,508	$ 20,537	$ 432,971
2	Nuclear power research expenses (elec.)......			
3	Other experimental and general research expenses......			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent......	1,682,703	76,201	1,606,502
7	Other expenses (items of $100 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $100 may be grouped by classes if the number	67,304	3,048	64,256
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)......	882,680	39,972	842,708
14				
15	Memberships and contributions (see detail on page 39)......	1,821,220	82,474	1,738,746
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 4,840,111	$ 222,233	$ 4,685,182

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

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

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Directors' Fees and Expenses:			
2	Richard Dahl - Fees	$ 87,057	$ 3,942	$ 83,115
3	J LaMont Keen - Fees and expenses	38,577	1,747	36,830
4	Christine King-Fees and expenses	87,459	3,961	83,498
5	Thomas Wilford - Fees and expenses	70,729	3,203	67,526
6	Jan Packwood-Fees and expenses	59,865	2,711	57,154
7	Judith Johansen-Fees and expenses	74,317	3,365	70,952
8	Joan Smith - Fees and expenses	81,611	3,696	77,915
9	Thomas Carlilel - Fees and expenses	54,585	2,472	52,113
10	Stephen Allred	32,475	1,471	31,004
11	Robert A Tinstman Fees and expenses	156,865	7,104	149,761
12	Ronald Jibson - Fees and expenses	69,622	3,153	66,469
13	Dennis Johnson - Fees and expenses	69,518	3,148	66,370
14	SUBTOTAL	882,680	39,972	842,707
15				
16	Miscellaneous General Management Expenses:			
17	Moody's Analytics Inc	32,729	1,482	31,247
18	American Stock Transfer & Trust	75,181	3,405	71,776
19	Broadridge Financial Solutions	49,240	2,230	47,010
20	Deutche Bank	43,482	1,969	41,513
21	E Source	35,756	1,619	34,137
22	Wells Fargo Shareowner Services	115,889	5,248	110,641
23	Stock Based Compensation	752,952	34,098	718,854
24	NASDAQ Corp Solutions	70,138	3,176	66,962
25	Miscellaneous General Management Expenses:	230,053	10,418	219,635
26	Rate Related Amortization	230,655	10,445	220,210
27	New York Stock Exchange	46,628	2,112	44,516
28	SUBTOTAL	1,682,703	76,201	1,606,501
29				
30	Memberships and Contributions:			
31	Associated Taxpayers of Idaho - Membership	23,000	1,042	21,958
32	Boston College Center for Corporation	5,000	226	4,774
33	Chamber of Commerce	91,165	4,128	87,037
34	Corporate Executive Board	86,120	3,900	82,220
35	Idaho Associaton of Commerce and Industry	14,000	634	13,366
36	Idaho Technology Council	12,750	577	12,173
37	Misc Memberships (10)	28,965	1,312	27,653
38	National Assoc of Directors	7,125	323	6,802
39	National HydroPower Association	33,482	1,516	31,966
40	North American Energy Standard	7,000	317	6,683
41	Northwest Power Pool	279,952	12,678	267,274
42	Pacific NW Utilities-Membership	38,869	1,760	37,109
43	Western Electricity Coordinating Council	1,163,224	52,677	1,110,547
44	Western Energy Institute	30,568	1,384	29,184
45	SUBTOTAL	1,821,220	82,474	1,738,746
46				
47	**TOTAL**	$ 4,386,603	$ 198,648	$ 4,187,955

OFFICERS

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

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

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

Line No.	Title (a)	Name of Officer (b)	Salary for yea Total	Salary for yea Oregon
1				
2	President & Chief Executive Officer…......................................	Darrel T Anderson	$ 575,000	$ 26,039
3				
4	Executive Vice President, Operations.......................................	Dan Minor	430,000	19,473
5				
6	Sr Vice President, General Counsel	Rex Blackburn	335,000	15,171
7				
8	Senior Vice President, Power Supply..	Lisa Grow	300,000	13,586
9				
10	Vice President, CFO and Treasurer …......................................	Steven R. Keen	315,000	14,265
11				
12	Vice President, Human Resources & Corp Sevices	Luci McDonald	265,000	12,001
13				
14	Vice President, Customer Operations	Warren Kline	260,000	11,774
15				
16	Vice President, Public Affairs...	Jeffrey Malmer	245,000	11,095
17				
18	Vice President Chief Risk Officer	Lori Smith	233,000	10,551
19				
20	Vice President Engineering & Construction..............................	Vern Porter	235,000	10,642
21				
22	Vice President, Controller & Chief Accounting Officer..............	Ken Petersen	215,000	9,736
23				
24	Vice President & Chief Information Officer ……………………	Lonnie Krawl	208,000	9,419
25				
26	Vice President, Regulatory Affairs...	Gregory Said	210,000	9,510
27				
28	Corporate Secretary..	Patrick Harrington	182,000	8,242
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				

POLITICAL ADVERTISING

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

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

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

Description	Account Charged	Amount
ACTUAL INCENTIVE TAX	426.400	$ 4,555
ADA CTY LINCOLN DAY COMMITTEE	"	600
AP ACCRUAL	"	69,710
ARNIE ROBLAN FOR STATE SENATE	"	2,500
ASSOCIATED TAXPAYERS OF I	"	200
AVISTA CORP	"	310
BENEFITS FROM 232016	"	38,168
BLOOMBERG FINANCE LP	"	5,700
BOB NONINI FOR STATE SENATE	"	1,000
BRAD LITTLE FOR IDAHO	"	6,000
BRAD WITT FOR STATE REPRESENTA	"	1,000
BRANDON HIXON FOR STATE REPRES	"	750
BRANDON WOOLF FOR STATE CONTRO	"	1,000
BRENT CRANE FOR STATE REPRESEN	"	750
BRENT HILL FOR STATE SENATE	"	500
BRUDIE FOR DISTRICT JUDGE	"	500
BUSINESS INSTITUTE FOR	"	2,500
CANYON COUNTY REPUBLICANS	"	500
CAROLINE TROY FOR STATE REPRES	"	750
CELL PHONE STIPEND	"	808
CHAMBER OF COMMERCE	"	2,500
CHAPSTICK W/CLIP	"	2
CHERIE BUCKNER-WEBB FOR STATE	"	750
CHUCK WINDER FOR STATE SENATE	"	1,000
CINDY AGIDIUS FOR STATE REPRES	"	1,000
COMMITTEE TO RE-ELECT GREG SMI	"	2,000
CORP INCENTIVE	"	162
CORP INCENTIVE FICA	"	12
CURT MCKENZIE FOR STATE SENATE	"	1,000
DAN JOHNSON FOR STATE SENATE	"	750
DAN SCHMIDT FOR STATE SENATE	"	1,250
DONNA PENCE FOR STATE REPRESEN	"	500
DOUGLAS HANCEY FOR STATE REPRE	"	500
DRINKWARE 20 OZ	"	7
ED MORSE FOR STATE REPRESENTIV	"	500
ELAINE SMITH FOR STATE	"	500
ELLIS PUBLIC AFFAIRS	"	10,921
ENVELOPE, NOTECARD,	"	12

POLITICAL CONTRIBUTIONS

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

Description	Account Charged	Amount
EXEC INCENT PR YR ADJ	426.400	$ 80
EXEC INCENTIVE	"	190,623
EXEC INCENTIVE FICA	"	2,764
FRED MARTIN FOR STATE SENATE	"	500
FRIENDS OF BILL HANSELL	"	1,000
FRIENDS OF MARK HASS	"	2,000
G SQUARED LLC	"	139,173
GARY COLLINS FOR STATE	"	500
GEORGE ESKRIDGE FOR STATE	"	500
GRANT BURGOYNE FOR STATE SENAT	"	750
GREEN CREATIVE	"	735
GREG CHANEY FOR STATE REPRESEN	"	250
GREG GFELLER FOR STATE REPRESE	"	750
HAHN,RICHARD L	"	186,060
HILTON,JULIA A	"	84
HOLMES,SANDRA D	"	339
HOPKINS RODEN CROCKETT HANSEN	"	24,000
HORTON FOR SUPREME COURT	"	3,193
HY KLOC FOR STATE REPRESENTATI	"	500
IDAHO ASSOC OF COMMERCE AND IN	"	1,780
IDAHO COUNCIL ON INDUSTRY	"	1,500
IDAHO DEMOCRATIC LEGISLATIVE C	"	750
IDAHO DEMOCRATIC PARTY	"	1,000
IDAHO LIABILITY REFORM COALITI	"	2,000
IDAHO MINING ASSOCIATION	"	6,000
IDAHO PETROLEUM COUNCIL	"	2,500
IDAHO PRIOR APPROPRIATION DOCT	"	50,000
IDAHO PROSPERITY FUND	"	33,500
IDAHO REPUBLICAN PARTY	"	2,500
IDAHO STATE DEMOCRAT PARTY	"	750
IDAHO STATE SOCIETY	"	13,927
IDAHO STATE UNIVERSITY	"	150
IDAHO WATER USERS ASSOCIA	"	2,200
IDAHOANS FOR SENSIBLE WATER RE	"	2,500
ILANA RUBLE FOR STATE REPRESEN	"	500
JANET TRUJILLO FOR STATE REPRE	"	1,000
JANIE WARD-ENGELKING FOR STATE	"	1,000

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
JEFF THOMPSON FOR STATE REPRES	426.400	$ 1,000
JIM GUTHRIE FOR STATE SENATE	"	750
JIM RICE FOR STATE SENATE	"	750
JOHN GANNON FOR STATE REPRESEN	"	500
JOHN GOEDDE FOR STATE SENATE	"	750
JOHN KITZHABER FOR GOVERNOR	"	10,000
JOHN MCCROSTIE FOR STATE REPRE	"	500
JOHN RUSCHE FOR STATE REPRESEN	"	1,000
JOHN TIPPETS FOR STATE SENATE	"	1,000
JUDY BOYLE FOR STATE REPRESENT	"	500
KATHLEEN SIMS FOR STATE REPRES	"	1,000
KELLEY PACKER FOR STATE REPRES	"	1,000
KEN ANDRUS FOR STATE REPRESENT	"	500
LANCE CLOW FOR STATE REPRESENT	"	500
LATAH COUNTY REPUBLICANS	"	1,000
LAWERENCE DENNEY FOR SECRETARY	"	2,500
LAWRENCE WASDEN FOR ATTORNEY	"	1,000
LEE HEIDER FOR STATE SENATE	"	750
LENORE BARRETT FOR STATE	"	500
LINDEN BATEMAN FOR STATE REPRE	"	500
LOBBY IDAHO, LLC	"	62,103
LORI DEN HARTOG FOR STATE SENA	"	500
LUKE MALEK FOR STATE REPRESENT	"	500
LYNN M LUKER FOR STATE REPRESE	"	500
MALMEN,JEFFREY L	"	323,489
MARC GIBBS FOR STATE REPRESENT	"	500
MARK NYE FOR STATE REPRESENTAT	"	500
MARV HAGEDORN FOR STATE SENATE	"	750
MAT ERPELDING FOR STATE REPRES	"	500
MCDONALD CARANO WILSON GOVERNM	"	16,311
MERRILL BEYELER FOR STATE REPR	"	500
MICHAEL LEWAN COMPANY	"	72,000
MICHELLE STENNETT FOR STATE SE	"	1,000
MIKE MOYLE FOR STATE REPRESENT	"	1,000
MINIATURE UTILITY TRUCK		7

POLITICAL CONTRIBUTIONS		
INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained. Report whole dollars only. Provide a total for each account and a grand total.		
Description	Account Charged	Amount
Misc Cash Acctg ID 0000308246	426.400	$ (218)
NATIONAL HYDROPOWER ASSOC	"	10,001
NELSON COMMUNICATIONS ASSOC	"	2,380
neon highliter with Ipco logo	"	5
NEW HORIZONS PAC	"	2,500
OREGONIANS FOR FOOD AND SHELTE	"	3,000
OXBOW MESSHALL/CREW	"	436
OXLEY & ASSOCIATES INC	"	60,995
PAT MCDONALD FOR STATE REPRESE	"	1,000
PATTI ANNE LODGE FOR	"	750
PAUL SHEPHERD FOR STATE REPRES	"	500
PAYROLL ACCR REVERSAL	"	(76,806)
PAYROLL ACCRUAL	"	77,577
PAYROLL TAX ACCRUAL	"	5,167
PHYLLIS KING FOR STATE REPRESE	"	500
PRO LETTER OPENER	"	1
PROM MUG 16 0Z	"	8
PROMO MOUSE PAD	"	3
PROMO ORG BLK	"	18
PROMOTE OREGON LEADERSHIP PAC	"	2,000
REED DEMORDAUNT FOR STATE REPR	"	500
REPUBLICAN GOVERNOR'S ASSOCIAT	"	25,000
Reversal-AP ACCRUAL	"	(69,710)
REVERSE CORP EXEC INCENT	"	(2,704)
REVERSE CORP INCENT FICA	"	(28)
RICH WILLS FOR STATE REPRESENT	"	500
RICK YOUNGBLOOD FOR STATE REPR	"	750
ROBERT ANDERST FOR STATE REPRE	"	750
RON CRANE FOR STATE TREASURER	"	500
ROY LACEY FOR STATE SENATE	"	750
RYAN KERBY FOR STATE REPRESENT	"	1,000
SCOTT BEDKE FOR STATE REPRESEN	"	1,000
SENATE REPUBLICAN PAC	"	500

POLITICAL CONTRIBUTIONS

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

Description	Account Charged	Amount
SHAWN KEOUGH FOR STATE SENATE	**426.400**	$ 1,000
STEPHEN HARTGEN FOR STATE REPR	"	500
STEPHEN SNEDDEN FOR STATE REPR	"	500
STEVE MILLER FOR STATE REPRESE	"	500
Stock Based Compensation	"	150,235
TERRY GESTRIN FOR STATE REPRES	"	500
THE KEMPTHORNE INSTITUTE	"	2,000
THOMAS DAYLEY FOR STATE REPRES	"	500
THYRA STEVENSON FOR STATE REPR	"	500
TODD LAKEY FOR STATE SENATE	"	250
TOM LOERTSCHER FOR STATE REPRE	"	500
UNIVERSITY OF IDAHO FOUNDATION	"	7,500
VISSER,JENNIFER J	"	2,695
WENDY HORMAN FOR STATE REPRESE	"	500
WIR TELECOM DIR CHRG		1,072
WIRELESS TEL PR DEDUCT		(140)
Total Political Contributions		**$ 1,561,921**

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

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

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

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

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

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

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP EMPLOYEES	426101	$ 100,280	None
IDACORP	426101	119,720	"
TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND		**220,000**	
AMERICAN CANCER SOCIETY	426102	200	"
AMERICAN RED CROSS OF GREATER	"	1,000	"
BASQUE FOUNDATION INC	"	300	"
BINGHAM COUNTY SEARCH & RESCUE	"	500	"
BOISE BASIN SENIOR CENTER	"	500	"
BOISE CENTENNIAL ROTARY CLUB	"	500	"
BOISE STATE UNIVERSTITY DANCE	"	500	"
BOYS & GIRLS CLUB OF ADA CO	"	2,500	"
BRUNEAU QUICK RESPONSE	"	5,150	"
CAMAS COUNTY SENIOR CENTER	"	250	"
CANYON COUNTY FESTIVAL	"	1,550	"
CASCADE FOOD PANTRY	"	100	"
CHAMBER OF COMMERCE	"	200	"
DESIGNS BY DE	"	1,913	"
EDEN-HAZELTON SENIOR CENTER	"	250	"
EMMETT FRIENDSHIP COALITION	"	500	"
FESTIVAL OF TREES	"	850	"
FILER SENIOR CENTER	"	250	"
FRANKLIN BUILDING SUPPLY	"	165	"
GIRL SCOUTS OF SILVER SAGE COU	"	3,000	"
GLANBIA CHARITY CHALLENGE	"	500	"
GOLDEN YEARS SENIOR CENTER	"	250	"
GOLF FOR A CAUSE	"	250	"
HARMON KILLEBREW MIRACLE FIELD	"	2,500	"
HUFFMAN,TERESA A	"	167	"
IDAHO COMMISSION ON HISPA	"	1,500	"

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

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

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

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDAHO FOODBANK	426.102	$ 1,350	None
IDAHO N HEROES OUTDOORS	"	250	"
LEMHI COUNTY CRISIS INTERVENTI	"	200	"
LIFE'S KITCHEN	"	1,000	"
LUPO,MARK J	"	1,109	"
MAN UP CRUSADE	"	500	"
MARTIN,FRANCES J	"	1,000	"
MERIDIAN POLICE DEPARTMENT	"	400	"
MINIATURE UTILITY TRUCK	"	100	"
MISC CORRECTIONS 5	"	(2,000)	"
MOUNTAIN HOME OFFICERS SPOUSES	"	200	"
MUSCULAR DYSTROPHY ASSOCIATION	"	300	"
NATIONAL FEDERATION OF THE BLI	"	750	"
NO OR MULTIPLE DESC	"	80	"
NOLAND,FRED H	"	302	"
NORTHWEST CHILDREN'S HOME	"	2,000	"
OAKLEY VALLEY SENIOR CENTER	"	250	"
PROMO FRISBEE	"	36	"
RICHFIELD SENIOR CENTER	"	250	"
ROCK CREEK RURAL FIRE DIPARTME	"	500	"
ROTARY CLUB OF NAMPA	"	100	"
ROTARY CLUB OF TWIN FALLS	"	600	"
SAINT ALPHONSUS FOUNDATION	"	500	"
SAINT ALPHONSUS NAMPA HEALTH F	"	150	"
SCALES OF JUSTICE BASS TOURNAM	"	400	"
SHEPHERD'S HOME INC	"	200	"
SHRINER HOSPITALS FOR CHILDREN	"	1,000	"
SNAKE RIVER SHRINE CLUB	"	225	"
SOUTH CENTRAL COMMUNITY	"	600	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
SOUTHEAST IDAHO SENIOR GAMES	426.102	$ 500	None
ST ALPHONSUS FESTIVAL OF TREES	"	5,000	"
ST LUKE'S CHILDRENS HOSPITAL	"	400	"
ST LUKES HEALTH FOUNDATION	"	5,000	"
ST LUKES MCCALL FOUNDATION	"	500	"
SUPPORTING ALL VOLUNTEER EMERG	"	100	"
THREE ISLAND PANTRY	"	200	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
YOYO	"	36	"
TOTAL HEALTH & HUMAN SERVICES		**50,432**	"
4-H CLUB	426.103	380	"
4-H FFA JUNIOR LIVESTOCK SALE	"	256	"
4-H FFA MARKET LIVESTOCK SALE	"	400	"
ABERDEEN, CITY OF	"	500	"
ACCESS TO JUSTICE IDAHO	"	1,500	"
ADAMS COUNTY FAIR	"	300	"
AIR MAGIC VALLEY 2014	"	500	"
AMERICAN FALLS BIRDING FESTIVA	"	200	"
AMERICAN HEART ASSOCIATION	"	2,500	"
AMERICAN LEGION POST #76	"	400	"
ARM MAST 2FT FLOOD	"	123	"
BAKER COUNTY FAIR - HALFWAY	"	785	"
BAKER COUNTY SHRINE CLUB	"	250	"
BANNOCK COUNTY SOUP BASKET	"	200	"
BENEFITS FROM 232016	"	706	"
BIG WATER BLOWOUT RIVER FESTIV	"	200	"
BIGGEST SHOW IN IDAHO	"	500	"
BLACKFOOT MARATHON	"	250	"
BLANKET PROMO ITEM	"	333	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BLT MCH GALV 5/8X12	426.103	$ 3	None
BOISE BASIN BOOSTERS	"	400	"
BOISE RIDGE RIDERS	"	200	"
BOISE YOUNG PROFESSIONALS	"	100	"
BOY SCOUTS OF AMERICA	"	167	"
BOY SCOUTS OF AMERICA OREGON T	"	250	"
BOYS & GIRLS CLUB OF ADA CO	"	5,000	"
BOYS AND GIRLS CLUB	"	400	"
BUHL, CITY OF	"	1,000	"
CAMBRIDGE RODEO BOARD	"	100	"
CANYON COUNTY FRATERNAL ORDER	"	250	"
CANYON COUNTY MARKET LIVESTOCK	"	500	"
CAPITAL GOLDEN EAGLE BOOSTER C	"	100	"
CASCADE MEDICAL CENTER	"	250	"
CASTLEFORD MENS CLUB	"	300	"
CHAMBER OF COMMERCE	"	11,309	"
CHAMBER OF COMMERCE, BOIS	"	150	"
CHAPSTICK W/CLIP	"	455	"
CITY OF BOISE	"	750	"
CITY OF IDAHO CITY	"	500	"
CITY OF POCATELLO	"	500	"
CLEANER CAR 2.5GA	"	13	"
CLNR FAST & EASY	"	3	"
COLBURN,MITCHEL D	"	2,538	"
COOLER PROMO ITEM	"	377	"
CORP INCENTIVE	"	501	"
CORP INCENTIVE FICA	"	38	"
CRIME STOPPERS OF SOUTHWEST ID	"	1,000	"
CROSSFIRE POLARIZED GLASSES	"	25	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
CROUCH/GARDEN VALLEY MUSEUM	426.103	$ 1,000	None
DELCURTO,DUSTIN B	"	239	"
DONNELLY CITY	"	450	"
DRESS FOR SUCCESS	"	160	"
DRINKWARE 20 OZ	"	14	"
ELKS LODGE	"	100	"
ELMORE COUNTY FRIENDS FOR RECO	"	100	"
EMMETT, CITY OF	"	300	"
FARRENS,JARED W	"	75	"
FLASHLIGHT PROMO	"	224	"
FOSDICK, THE	"	400	"
FRIENDS OF ZOO BOISE	"	2,500	"
FRUITLAND COMMUNITY EVENTS	"	300	"
FUNDSY	"	6,500	"
GARDEN CITY POLICE OFFICER'S A	"	500	"
GATE CITY BOXING CLUB	"	225	"
GEM BOISE COUNTY FAIR	"	500	"
GEM COUNTY SHERIFF POSSE	"	200	"
GLAZE,MICHELLE R	"	477	"
GOD & COUNTY FAMILY FESTIVAL	"	250	"
GOLD DUST RODEO	"	500	"
GOLF BALLS	"	574	"
GOLF TEES	"	34	"
GROUCH/GARDEN VALLEY MUSEUM	"	460	"
H.S. JESHUA MINISTRIES	"	300	"
HEARTLAND HUNGER & RESOURCE CE	"	1,000	"
HORSESHOE BEND CITY	"	800	"
HUNTINGTON LIONS CLUB	"	250	"
IDAHO BOTANICAL GARDEN	"	3,000	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
IDAHO CHAPTER AMERICAN	426.103	$ 1,350	None
IDAHO CHAPTER OF THE	"	500	"
IDAHO CITY LITTLE LEAGUE	"	325	"
IDAHO COMMUNITY FOUNDATION	"	2,500	"
IDAHO COWBOY ASSOCIATION	"	250	"
IDAHO ECONOMIC DEVELOPMENT ASS	"	500	"
IDAHO HIGH SCHOOL RODEO ASSOC	"	300	"
IDAHO HISTORIC LODGE #1863	"	191	"
IDAHO HORSE RESCUE	"	500	"
IDAHO HUMAN RIGHTS	"	750	"
IDAHO HUMANE SOCIETY	"	3,000	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO STATE HISTORICAL SOCIETY	"	500	"
IDAHO STATE POLICE	"	1,000	"
IDAHO STATE UNIVERSITY	"	2,700	"
JENSEN,BARBARA V	"	1,200	"
JORDAN VALLEY JUNIOR RODEO	"	150	"
KETCHUM WAGON DAYS	"	250	"
KIWANIS CLUB OF EAGLE	"	250	"
KIWANIS CLUB OF NAMPA	"	100	"
KIWANIS CLUB OF NEW PLYMOUTH	"	200	"
KIWANIS CLUB OF ONTARIO	"	250	"
KIWANIS CLUB OF POCATELLO	"	75	"
KIWANIS CLUB OF TREASURE VALLE	"	200	"
KNIFE 7 IN 1, S.S.	"	59	"
KUNA YOUTH SOFTBALL & BASEBALL	"	250	"
LAMP HPS 200W	"	19	"
LANYARD SLIP-RING	"	42	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
LEMHI COUNTY ECONOMIC DEVELOPM	426.103	$ 60	None
LINDSAY,BRIAN D	"	508	"
LIONS CLUB	"	280	"
LIONS CLUB, MOUNTAIN HOME	"	200	"
LMNR HPS 200W FLOOD	"	546	"
LUPO,MARK J	"	3,992	"
MALHEUR COUNTY JUNIOR LIVESTOC	"	750	"
MARTIN,FRANCES J	"	2,000	"
MCPAWS REGIONAL ANIMAL SHELTER	"	350	"
MEADOWS VALLEY COMMUNITY FOUND	"	200	"
MERIDIAN EDUCATION FOUNDATION	"	150	"
MERIDIAN FFA CHAPTER	"	750	"
MERIDIAN, CITY OF	"	750	"
MINIATURE UTILITY TRUCK	"	27	"
Misc Cash Acctg ID 0000305919	"	(50)	"
MISC CORRECTIONS 1	"	(950)	"
MISC CORRECTIONS 4	"	1,358	"
MISC CORRECTIONS 5	"	2,000	"
MOUNTAIN HOME FIRE DEPARTMENT	"	300	"
NEIGHBORHOOD HOUSING	"	3,000	"
NO OR MULTIPLE DESC	"	389	"
NYSSA NITE RODEO	"	250	"
OAKLEY VIGILANTEES	"	250	"
OLD FORT BOISE MEMORIAL	"	250	"
OPTIMIST CLUB	"	100	"
OREGON ARCHEOLOGY CELEBRATION	"	250	"
OWYHEE BUTTER TOFFEE	"	2,257	"
OWYHEE COUNTY HORSE 4-H LEADER	"	200	"
OWYHEE COUNTY JUNIOR LIVESTOCK	"	400	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
OWYHEE OWYHEE BUTTER	426.103	$ 167	None
PAULIN,MATTHEW T	"	59	"
PAYETTE CIVIC LEAGUE	"	80	"
PAYETTE COUNTY RODEO	"	250	"
PAYROLL ACCR REVERSAL	"	(587)	"
PAYROLL ACCRUAL	"	552	"
PAYROLL TAX ACCRUAL	"	35	"
PEREGRINE FUND INC, THE	"	5,000	"
PFEIFFER,FRANK B	"	158	"
PINE SENIOR CENTER	"	100	"
POCATELLO / CHUBBUCK SCHOOL DI	"	1,500	"
POCATELLO H.S.	"	100	"
POCATELLO MARATHON	"	1,000	"
POE,VANCE T	"	231	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"
PRO LETTER OPENER	"	45	"
PROM MUG 16 0Z	"	105	"
PROMO 1/2" COTTON LANYARD	"	93	"
PROMO ORG BLK	"	71	"
PROMO ROAD SIDE SAFETY KITS	"	133	"
PROMO SAFETY ICE SCRAPPER	"	19	"
PROMOTIONAL APPAREL	"	98	"
ROCKY MOUNTAIN ELK FOUNDATION	"	1,750	"
ROTARY CLUB	"	850	"
ROTARY CLUB OF	"	100	"
ROTARY CLUB OF NAMPA	"	500	"
ROTARY CLUB, BOISE	"	250	"
ROTARY CLUB, BOISE-SUNRIS	"	500	"
ROTARY CLUB, HAILEY	"	500	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
ROWEN,CASEY L	426.103	$ 711	None
SALMON RIVER COWBOYS	"	200	"
SALMON RIVER JET BOAT RAC	"	350	"
SCREW LAG 1/2X4 IN	"	2	"
SILVER WINGS OF IDAHO	"	5,000	"
SIMPSON,LARAMIE B	"	263	"
SMART WOMEN, SMART MONEY INC	"	5,000	"
SOUTHERN IDAHO TOURISM	"	250	"
SPONGE CLEANSING HD POLY	"	7	"
SPORTS BOTTLE - PROMO	"	79	"
ST LUKE'S ELMORE MEDICAL CENTE	"	250	"
STAR, CITY OF	"	500	"
STUTZMAN,SHARON E	"	1,404	"
TABLE ROCK CHALLENGE	"	400	"
TANAKA,CARLTON I	"	259	"
THE GOOD SAMARITAN HOME	"	500	"
THERMOS SSL	"	383	"
THOMAS,ELIZABETH M	"	52	"
THURMAN,DOUGLAS K	"	446	"
TRAILING OF THE SHEEP FESTIVAL	"	250	"
TREASURE VALLEY RAPTOR RESCUE	"	500	"
TROUT UNLIMITED	"	1,500	"
TWIN FALLS COUNTY FAIR FOUNDAT	"	500	"
TWIN FALLS OPTIMIST CLUB	"	150	"
TWIN FALLS RAPIDS SOCCER CLUB	"	250	"
VETERANS DAY PARADE COMMITTEE	"	500	"
VETERANS OF FOREIGN WARS	"	250	"
WARHAWK AIR MUSEUM	"	1,500	"
WASHINGTON COUNTY 4H/FFA	"	250	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
WASHINGTON COUNTY FAIR BOARD	426.103	$ 505	None
WATER BOTTLE PROMO ITEM	"	66	"
WATSON,BLAKE J	"	100	"
WELCOME HOME	"	300	"
WEWERS,BRYAN J	"	1,152	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
WSHR SQ 2 1/4X11/16	"	1	"
WYAKIN WARRIOR FOUNDATION	"	1,000	"
YBARGUEN,MICHAEL D	"	114	"
YMCA OF TWIN FALLS	"	2,500	"
TOTAL CIVIC & COMMUNITY		**147,472**	"
BOISE ART MUSEUM	426.104	3,000	"
BOISE CONTEMPORARY THEATER INC	"	1,000	"
BOISE MUSIC WEEK	"	1,000	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"
CHILDREN'S HOME SOCIETY OF ID	"	1,250	"
COMMUNITY CONCERTS OF	"	250	"
CORNUCOPIA ARTS COUNCIL	"	250	"
CROSSROADS CARNEGIE ART CENTER	"	300	"
DANNY MARONA PERFORMING ARTS	"	500	"
DREXEL H FOUNDATION	"	200	"
EAGLE ARTS COMMISSION	"	250	"
FOUR RIVERS CULTURAL CENTER	"	500	"
IDAHO ACADEMIC DECATHLON	"	1,250	"
IDAHO CITY HISTORICAL	"	250	"
IDAHO HUMANITIES COUNCIL	"	600	"
IDAHO SHAKESPEARE FESTIVAL	"	3,000	"
IDAHO WATERCOLOR SOCIETY	"	300	"
JEROME MUSIC BOOSTERS	"	50	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
LOG CABIN LITERARY CENTER	426.104	1,500	Nnoe
MAGIC VALLEY SYMPHONY	"	300	"
MCCALL ARTS & HUMANITIES COUNC	"	150	"
MCCALL, CITY OF	"	300	"
MERIDIAN ARTS COMMISSION	"	500	"
MERIDIAN SYMPHONY ORCHESTRA	"	750	"
MOUNTAIN HOME	"	400	"
NAMPA FESTIVAL OF THE ARTS	"	350	"
OWYHEE COUNTY HISTORICAL SOCIE	"	250	"
SHOSHONE VETERANS MEMORIAL	"	300	"
THE SUN VALLEY BALLET SCHOOL	"	100	"
TOTAL CULTURE & ARTS		**21,350**	"
IDAHO PUBLIC TELEVISION	426.105	18,430	"
TOTAL PUBLIC TV & RADIO		**18,430**	"
BLAZING HOPE YOUTH	426.106	100	"
BOGUS BASIN SNOWSCHOOL	"	100	"
BOISE CITY PARKS AND RECREATIO	"	100	"
BOISE RIVERSIDE SPECIAL OLYMPI	"	100	"
BOISE STATE PUBLIC RADIO	"	100	"
BOY SCOUTS OF AMERICA	"	700	"
BOY SCOUTS OF AMERICA - GRAND	"	100	"
BOY SCOUTS OF AMERICA - TEAM 2	"	100	"
BOY SCOUTS OF AMERICA BLACKFOO	"	100	"
BOY SCOUTS OF AMERICA OREGON T	"	100	"
BOYS SCOUTS OF AMERICA POCATEL	"	100	"
CANYON RIDGE HIGH SCHOOL BASEB	"	100	"
CARRIBOO CONSERVANCY, INC	"	100	"
CITY OF AMERICAN FALLS CLERK'S	"	250	"
DUCKS UNLIMITED	"	100	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
DUSTIN CURTIS MEMORIAL SCHOLAR	426.106	$ 100	None
IDAHO BOTANICAL GARDEN	"	100	"
IDAHO HUMANE SOCIETY	"	250	"
IDAHO SCHOOL FOR THE DEAF AND	"	100	"
IDAHO STATE UNIVERSITY	"	100	"
JAPANESE AMERICAN	"	500	"
KIWANIS CLUB OF CAPITAL CITY	"	100	"
MIDDLETON HEIGHTS ELEMENTARY	"	100	"
MONROE ELEMENTARY SCHOOL	"	100	"
PAYETTE LAKES SKI PATROL	"	100	"
ROCKY MOUNTAIN HIGH SCHOOL	"	100	"
ROTARY CLUB OF	"	100	"
SALMON SEARCH AND RESCUE	"	500	"
SALMON VOLUNTEER FIRE DEPT	"	100	"
SALMON YOUTH HOCKEY ASSOC	"	100	"
ST ALPHONSUS FESTIVAL OF TREES	"	100	"
ST LUKES GIFT SHOP	"	100	"
TWIN FALLS COUNTY YOUTH BASEBA	"	100	"
UNIVERSITY OF IDAHO	"	200	"
UPWARD BASKETBALL AND CHEERLEA	"	100	"
VALLEY WIDE REACT TEAM 4956	"	100	"
WOMEN'S & CHILDREN'S ALLIANCE	"	100	"
TOTAL VOLUNTEER INVOLVEMENT PROGRAM		**5,500**	"
SALVATION ARMY	426.107	44,237	"
TOTAL PROJECT SHARE		**44,237**	"
DUCKS UNLIMITED	426.108	200	"
DUDGEON,MELISSA L	"	750	"
FRIENDS OF THE WEISER RIVER	"	250	"
LAKE CASCADE STATE PARK	"	100	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
MOUNTAIN HOME, CITY OF	426.108	$ 400	None
PEARSON,JOSHUA W	"	212	"
TOTAL ENVIRONMENT & CONSERVATION		**1,912**	"
ANIMALS IN DISTRESS	426.109	1,000	"
AQUARIUM OF BOISE	"	5,000	"
BISHOP KELLY FOUNDATION I	"	1,000	"
BOISE IDAHO VETERANS ASSISTANC	"	1,000	"
IDAHO GOVERNERS CUP	"	18,500	"
IDAHO HUMANE SOCIETY	"	10,000	"
KEEN,STEVEN R	"	9,120	"
POCATELLO IDAHO VETERANS ASSIS	"	1,000	"
ST LUKES REGIONAL MEDICAL	"	1,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	1,000	"
WOOD RIVER COMMUNITY YMCA	"	5,000	"
TOTAL NON-PROGRAM		**53,620**	"
4-H FFA JUNIOR LIVESTOCK SALE	426.110	256	"
4-H MARKET SALE	"	400	"
ABERDEEN YOUNG WOMAN SCHOLARSH	"	200	"
BANNOCK COUNTY YOUTH STOCK SAL	"	200	"
BENGAL FOUNDATION	"	400	"
BINGHAM COUNTY MARKET ANIMAL	"	350	"
BOB MCKINNEY MEMORIAL GOLF TOU	"	100	"
BOISE PUBLIC SCHOOLS	"	100	"
BOISE SCHOOLS EDUCATION FOUNDA	"	3,000	"
BOISE STATE UNIVERSITY COLLEGE	"	2,000	"
BOY SCOUTS OF AMERICA	"	333	"
BRUNEAU ELEMENTARY SCHOOL	"	250	"
BURLEY HIGH SCHOOL	"	50	"
CANYON COUNTY VANDAL BOOSTER	"	150	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
CASCADE PUBLIC LIBRARY	426.110	$ 100	None
CASCADE SOBER GRADUATION	"	100	"
CHAMBER OF COMMERCE	"	550	"
COLLEGE OF IDAHO	"	3,000	"
COLLEGE OF SOUTHERN IDAHO	"	3,000	"
COLLEGE OF WESTERN IDAHO FOUND	"	4,600	"
COUNCIL HIGH SCHOOL	"	100	"
DESERT SPRINGS ELEMENTARY SCHO	"	100	"
DISCOVERY CENTER OF IDAHO	"	1,000	"
DISTINGUISHED YOUNG WOMEN OF B	"	250	"
DUAL CREDIT SCHOLARSHIP - SCHO	"	550	"
DUDGEON,MELISSA L	"	750	"
EAGLE HIGH SCHOOL GRAD ALL-NIG	"	100	"
FILER HIGH SCHOOL SENIOR	"	50	"
FUTURE FARMERS OF AMERICA	"	500	"
GARDEN CITY LIBRARY FOUNDATION	"	500	"
GEM STATE FLY FISHERS	"	200	"
GLENNS FERRY HIGH SCHOOL	"	100	"
GOODING HIGH SCHOOL	"	75	"
GRAD NIGHT	"	100	"
GRAND VIEW YOUTH NIGHT	"	100	"
HIGH SCHOOL RODEO ASSOCIATION	"	200	"
IDAHO COUNCIL ON INDUSTRY	"	250	"
IDAHO HIGH SCHOOL RODEO ASSOC	"	300	"
IDAHO SNAKE RIVER CHAPTER, AAA	"	200	"
IDAHO STATE CIVIC SYMPHONY	"	110	"
IDAHO STATE UNIVERSITY	"	2,500	"
IDAHO: OPERATION MILITARY KID	"	200	"
JALAPENO OPEN	"	250	"

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

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

Description	Account Number	Total Amount	Amount Assigned to Oregon
JUNIOR ACHIEVEMENT OF IDAHO	426.110	$ 2,500	None
KUNA HIGH SCHOOL PARENT TEACHE	"	100	"
LEARNING LAB	"	1,000	"
LEMHI COUNTY JUNIOR LIVESTOCK	"	350	"
LUPO,MARK J	"	432	"
MAYOR'S COMMUNITY SERVICE SCHO	"	500	"
MELBA HIGH SCHOOL	"	100	"
MERIDIAN FFA CHAPTER	"	250	"
MOUNTAIN HOME HIGH SCHOOL	"	100	"
NAMPA ASSOCIATION OF REALTORS	"	75	"
NAMPA HIGH PROJECT GRADUATION	"	100	"
NAMPA, CITY OF	"	200	"
NEW PLYMOUTH ELEMENTARY SCHOOL	"	200	"
NEW PLYMOUTH HIGH SCHOOL	"	100	"
NEWSPAPERS IN EDUCATION	"	300	"
NORTHEAST OREGON AREA HEALTH E	"	250	"
NORTHWEST NAZARENE UNIVERSITY	"	3,000	"
OLMSTEAD,DANIEL H	"	250	"
OPTIMIST CLUB OF MCCALL	"	100	"
OPTIMIST CLUB OF MTN HOME	"	250	"
POWER COUNTY 4 H/FFA LIVE	"	499	"
RIMROCK BOOSTER CLUB	"	200	"
ROTARY CLUB	"	150	"
ROTARY CLUB OF	"	250	"
ROTARY CLUB OF TWIN FALLS	"	350	"
ROTARY CLUB, BOISE	"	500	"
SALMON RIVER HIGH SCHOOL	"	100	"
SKYVIEW HIGH SCHOOL	"	100	"
SOCIETY OF WOMEN ENGINEERS	"	2,000	"

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

Description	Account Number	Total Amount	Amount Assigned to Oregon
STATE OF IDAHO DEPARTMENT OF E	426.110	$ 1,000	None
TESLA COILS 5026 WORLD TRIP	"	350	"
TREASURE VALLEY COMMUNITY COLL	"	3,000	"
TWIN FALLS LIONS	"	250	"
UNITED SIGNERS CLUB	"	500	"
UNIVERSITY OF IDAHO	"	300	"
UPPER COUNTRY EDUCATION FOUNDA	"	200	"
VALLIVUE SECURE & SOBER GRAD N	"	100	"
TOTAL EDUCATION		**47,630**	"
BOISE STATE UNIVERSITY	426.111	10,000	"
BRIGHAM YOUNG UNIVERSITY	"	6,000	"
BRIGHAM YOUNG UNIVERSITY CES A	"	5,000	"
COLLEGE OF IDAHO	"	2,000	"
COLLEGE OF SOUTHERN IDAHO	"	4,000	"
DIXIE STATE UNIVERSITY	"	2,000	"
IDAHO STATE UNIVERSITY	"	8,000	"
Misc Cash Acctg ID 0000294801	"	(1,000)	"
Misc Cash Acctg ID 0000298892	"	(1,000)	"
Misc Cash Acctg ID 0000303618	"	(1,000)	"
Misc Cash Acctg ID 0000307023	"	(2,000)	"
Misc Cash Acctg ID 0000313325	"	(2,000)	"
OREGON STATE UNIVERSITY	"	2,000	"
PORTLAND STATE UNIVERSITY	"	2,000	"
U C BERKLEY	"	2,000	"
UNIVERSITY OF ARIZONA	"	2,000	"
UNIVERSITY OF IDAHO	"	9,000	"
WESTMINSTER COLLEGE	"	2,000	"
WHEATON COLLEGE	"	2,000	"
TOTAL SCHOLARSHIP PROGRAM	426.112	**51,000**	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BOISE STATE UNIVERSITY	426.112	$ 2,400	None
BRIGHAM YOUNG UNIVERSITY	"	200	"
BRIGHAM YOUNG UNIVERSITY- IDAH	"	1,000	"
CARLETON COLLEGE	"	50	"
COLLEGE OF IDAHO	"	2,175	"
COLORADO COLLEGE, THE	"	100	"
DUKE UNIVERSITY	"	300	"
IDAHO STATE UNIVERSITY	"	2,850	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
OREGON STATE UNIVERSITY	"	1,000	"
SHIMER COLLEGE	"	300	"
TRUSTEES OF THE UNIVERSITY OF	"	300	"
U S NAVAL ACADEMY FOUNDATION	"	100	"
UNIVERSITY OF IDAHO FOUNDATION	"	9,950	"
UNIVERSITY OF SOUTHERN CALIFOR	"	100	"
UNIVERSITY OF WISCONSIN	"	250	"
UTAH STATE UNIVERSITY	"	100	"
WASHINGTON STATE UNIVERSITY FO	"	300	"
TOTAL MATCH HIGHER EDUCATION		**23,475**	"
BANNOCK DEVELOPMENT CORPO	426.121	694	"
BOISE VALLEY ECONOMIC PARTNERS	"	4,000	"
CHAMBER OF COMMERCE	"	11,624	"
DONNELLY CITY	"	1,063	"
DOWNTOWN BOISE ASSOCIATION	"	2,250	"
GREAT RIFT BUSINESS DEVELOPMEN	"	1,430	"
IDAHO ECONOMIC DEVELOPMENT ASS	"	1,000	"
MERIDIAN, CITY OF	"	5,000	"
NAMPA, CITY OF	"	4,000	"
SNAKE RIVER ECONOMIC DEVELOPME	"	3,040	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
SOUTHERN IDAHO ECONOMIC DEVELO	426.121	$ 5,000	None
STREEBY, DIAN	"	1,000	"
SUN VALLEY ECONOMIC DEVELOPMEN	"	2,453	"
VALLEY COUNTY ECONOMIC DEVELOP	"	495	"
TOTAL ECONOMIC RECOVERY		**43,049**	"
2006 FORD F550 36' SERVICE BUC	426.130	119	"
2013 DODGE 5500 36' VERSALIFT	"	44	"
ACTUAL INCENTIVE TAX	"	3	"
APRIL MATERIAL TRANSFER	"	8,500	"
BECK,BRET E	"	51	"
BENEFITS FROM 232016	"	106	"
BLACKWELL,RICHARD B	"	102	"
CORP INCENTIVE	"	58	"
CORP INCENTIVE FICA	"	4	"
CUTLER,BRENT V	"	203	"
JANUARY MATERIAL TRANSFER	"	9,000	"
JOHNS,STEVEN A	"	586	"
MISC CORRECTIONS 3	"	300	"
PAYROLL ACCR REVERSAL	"	(234)	"
PAYROLL ACCRUAL	"	138	"
PAYROLL TAX ACCRUAL	"	9	"
REVERSE CORP INCENT FICA	"	(3)	"
TOTAL NON-CASH CONTRIBUTIONS		**18,988**	
TOTAL CONTRIBUTIONS ACCOUNT 426.1		$ 747,095	

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

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

2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	ALEMBA GROUP INC	IT Support Services	$ 1,322
2	ANDERSON BANDUCCI PLLC	Legal Services	6,023
3	BAKER BOTTS LLP	Legal Services	6,210
4	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	21,458
5	BERGLES LAW LLC	Legal Services	1,831
6	DAVIS WRIGHT TREMAINE LLP	Legal Services	59,282
7	ELAM AND BURKE PA	Legal Services	2,071
8	EVERGREEN CONSULTING GROUP, LL	Management Services	6,090
9	EVERGREEN ECONOMICS, INC.	Management Services	3,742
10	GIVENS PURSLEY LLP	Legal Services	13,870
11	HDR ENGINEERING, INC	Engineering Services	1,430
12	HONEYWELL INTERNATIONAL INC	Management Services	43,198
13	ISS CORPORATE SERVICES, INC	Management Services	1,585
14	MAINLINE INFORMATION SYSTEMS I	Management Services	2,337
15	MCDOWELL RACKNER & GIBSON PC	Legal Services	33,040
16	MIRANDE, MICHAEL	Legal Services	1,663
17	NETIQ	Data Center Management Services	1,793
18	NIELSEN GROUP INC, THE	Management Services	6,227
19	OXFORD GLOBAL RESOURCES INC	Management Services	2,745
20	PAINE HAMBLEN LLP	Legal Services	2,028
21	PARR BROWN GEE & LOVELESS INC	Legal Services	1,406
22	PERKINS COIE LLP	Legal Services	12,594
23	RM ENERGY CONSULTING	Management Services	10,109
24	SCHWABE WILLIAMSON & WYATT	Legal Services	1,894
25	STATE OF IDAHO	Management Services	4,529
26	STEPTOE & JOHNSON LLP	Legal Services	12,210
27	STOEL RIVES LLP	Legal Services	1,155
28	TERRACON	Engineering Services	2,444
29	TETRA TECH MA INC	Environmental Services	2,488
30	THINK BIG SOLUTIONS INC	Management Services	2,084
31	TUERI LLC	Management Services	5,336
32	UNIVERSITY CORPORATION FOR	Cloud Seeding & Modeling Services	6,377
33	UNIVERSITY OF IDAHO	Management Services	24,386
34	VAN NESS FELDMAN	Legal Services	42,930
35			
36			
37			
38			
41			
42			
43			
44	Total		$ 347,886
45			
46			

2014 IDACORP Annual Report

To Our Valued Shareholders:

2014 was a good year for IDACORP and Idaho Power Company, our primary subsidiary. We achieved earnings growth for a seventh consecutive year. We draw our strength from a solid foundation as an Idaho-based, fully integrated electric utility. Our continued focus on optimization of the business plan, proactive partnerships and customer satisfaction adds significantly to shareholder value. We are proud to be your independent, locally operated power company.

The business community realizes something we've known for a long time: Idaho is a great place to live and work. 2014 brought more national recognition to our state and our company. *Time Magazine* named Boise the number one city for "Getting it Right," and respected industry publication *Public Utilities Fortnightly* once again named Idaho Power to its prestigious list of "40 Best Energy Companies." We improved our ranking to 17, up from 29.

At IDACORP, we believe competitively priced electric service is essential to a healthy economy. In 2014, we continued to actively participate and support state and local economic development initiatives. From programs and incentives available to commercial and industrial customers to economic development grants offered to qualified nonprofit organizations, it's important to us that we do our part to help attract, retain and expand business and industry in our communities.

We continuously look for ways to increase shareholder value. In 2014, we increased the regular quarterly cash dividend to $0.47 per share from $0.43 per share, representing a 9 percent increase, and a collective 57 percent increase since 2012. We'll continue to recommend increasing our dividends until they reach the upper end of 50 percent to 60 percent of our sustainable earnings.

For our customers, we were pleased to be able to again share our earnings under our 2011 Idaho settlement agreement. Idaho Power earnings exceeding a 10 percent return on year-end equity in the Idaho jurisdiction are shared between Idaho customers and the company. We've shared $118 million with our customers since 2009. During 2014 we executed a new


Robert A. Tinstman
Darrel Anderson

2014 HIGHLIGHTS

Dollar Amounts in Thousands, Except Per Share Amounts	2014	2013	% Change
Total Operating Revenues	$1,282,524	$1,246,214	2.9
IDACORP Net Income	$193,480	$182,417	6.1
Earnings Per Diluted Common Share	$3.85	$3.64	5.8
Dividends Declared Per Common Share	$1.76	$1.57	12.1
Total Assets	$5,716,853	$5,364,563	6.6
Number of Employees (full-time)	2,021	2,023	–0.1

settlement stipulation that provides us with some of the benefits of the 2011 agreement, potentially through 2019. We believe this is a win for both our shareholders and our customers.

IDACORP continues to advance a sizable capital investment strategy, including its significant transmission line projects. At the end of 2014, we achieved a notable milestone in one of Idaho Power's two 500-kilovolt projects, when the Bureau of Land Management released the draft Environmental Impact Statement for the 300-mile Boardman to Hemingway transmission line.

While pursuing growth opportunities, we also plan for that growth. Our biennial Integrated Resource Plan (IRP) is well underway. The IRP is our 20-year roadmap that captures the company's vision for our region's energy needs and generation resources. The IRP is developed through a collaborative process with a sitting advisory committee representing a cross-section of interests and agencies. The 2015 IRP will be filed this summer.

We'll wrap up with a message about safety, a core value of our company and a value we extend to our customers in the communities we serve. Working safely is vital to our business and to the success of our most valuable asset, our talented and dedicated employees. In 2014, Idaho Power employees, leaders and executives renewed their commitment to our culture of safety — and we've made good progress. Our injury record was reduced in 2014 by nearly 40 percent.

Our success is built on a strong team. The leadership, innovation and strategic guidance from our Board of Directors and the 2,000-plus employees of IDACORP bring stability and strength to all we do and everything we achieve. In 2014, our employees rated us in the top quartile of a benchmark employee engagement survey. As our workforce evolves and changes through retirements and natural attrition, we will continue to effectively manage succession through targeted recruiting and employee knowledge transfer. Together, we proudly serve our communities — in our work and as volunteers — strengthening our bonds and delivering on our unwavering commitment to be good corporate citizens and good neighbors.

For nearly 100 years, we've operated as an independent utility — responsibly managing electricity production, delivery and planning. We look forward to continuing our legacy, building a secure energy future for our shareowners and our customers. Thank you for your trust and confidence in our company. We look forward to another year of progress and success.

Robert A. Tinstman
Chairman of the Board

Darrel Anderson
President and Chief Executive Officer

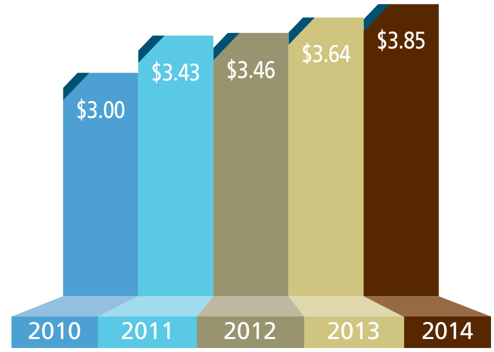

Boise, Idaho

Idaho Power Headquarters

Financial Strength and Strong Results

2014 Earnings-Per-Share Growth

IDACORP is pleased to report that 2014 was another successful year for our company, and our seventh consecutive year of earnings-per-share growth. In 2014, IDACORP's diluted earnings per share were $3.85.

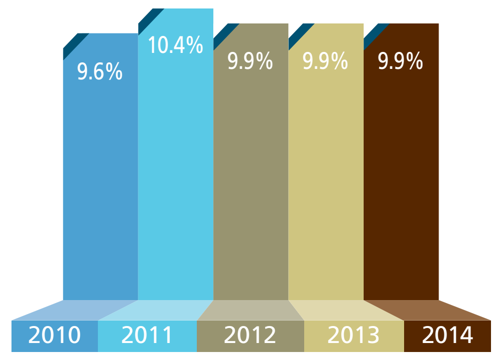


Diluted Earnings Per Share

Settlement Stipulation and Sharing With Customers

Idaho Power, IDACORP's primary subsidiary, had a 2014 return on year-end equity in the Idaho jurisdiction exceeding 10.5 percent, which resulted in the company using no additional amortization of accumulated deferred investment tax credits (ADITC) under the 2011 Idaho regulatory settlement stipulation. In fact, for yet another year Idaho Power will share earnings with Idaho customers under that stipulation.

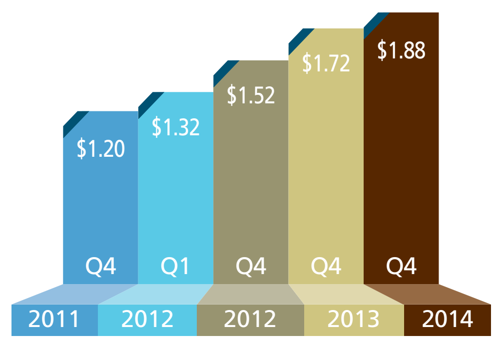
Additionally, during 2014 Idaho Power executed a new settlement stipulation that may provide the company with some of the benefits of the 2011 settlement, potentially through 2019, which we believe benefits both our shareholders and our customers. We have shared $118 million with our customers since 2009.



Return on Year-End Equity

2015 Guidance

On Feb. 19, 2015, IDACORP initiated its 2015 full-year earnings per share guidance in the range of $3.65 to $3.80, and is not expected to use any additional ADITCs in 2015. This estimate reflects continued benefits from tax method changes, normal weather conditions and ongoing cost management.

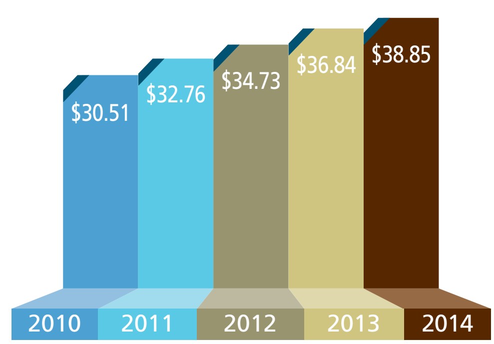


Annualized Dividend Per Share

Dividend Policy Progress

IDACORP's dividend has been an area of ongoing focus for several years. From 2012 through 2014, IDACORP's Board of Directors has approved a collective 57 percent increase in the quarterly dividend, from $0.30 to $0.47 per share. On Sept. 18, 2014, the IDACORP Board approved an increase in the quarterly dividend from $0.43 per share to $0.47 per share — a 9 percent increase.

This is continued progress toward achieving IDACORP's previously adopted target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings. On Sept. 18, 2014, IDACORP management stated that it anticipates recommending to the IDACORP board additional annual increases of over 5 percent until the dividend reaches the upper end of the target dividend payout ratio.



Book Value Per Share

Diverse Resource Portfolio Brings Security and Stability

Brownlee Dam

17 hydroelectric generating plants on the Snake River and its tributaries

Hydroelectric Generation

A diverse and balanced fuel mix means stability, for both power production and customer rates.

Idaho Power has relied on clean, renewable energy resources for nearly a century. Our commitment to green energy started with hydroelectric power and continued through power purchase agreements with the first large-scale wind development on our system and two geothermal plants. Today, almost 60 percent of the power on our system comes from hydroelectric and other renewable energy sources, with many more megawatts poised to come online.

Idaho Power's series of 17 hydroelectric dams on the Snake River and its tributaries comprise nearly half of the company's nameplate generation capacity. Idaho Power's hydroelectric generation during 2014 was 6.2 million megawatt-hours (MWh), compared to actual generation of 5.7 million MWh in 2013 and 8.0 million MWh in 2012. Median annual hydroelectric generation is 8.5 million MWh. On Feb. 19, 2015, Idaho Power estimated the 2015 generation from its hydroelectric facilities at between 7.0 million MWh and 9.0 million MWh.

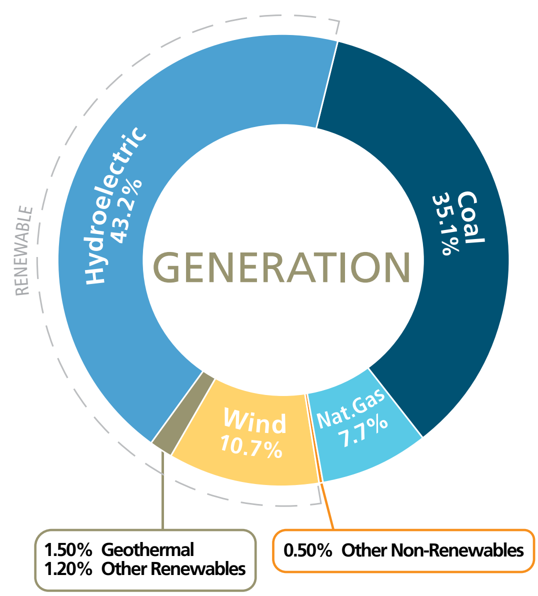
It is important to remember that the availability and volume of hydroelectric power generated depends on several factors, including snow pack levels in the mountains upstream of Idaho Power's facilities, reservoir storage, water leases and other water rights, and other weather and stream flow considerations.

Security

Coal- and Natural Gas-fired Generation

In addition to hydroelectric generation, Idaho Power relies on coal and natural gas to fuel its generation facilities and on power purchases in the wholesale markets. The company is part owner in three coal-fired generating plants. On the natural gas side, Idaho Power owns and operates its newest generation resource, the 318-megawatt (MW) combined-cycle combustion turbine Langley Gulch Power Plant, as well as two natural gas "peaker" plants.

2014 Resource Portfolio Fuel Mix*



*Because Idaho Power sells (or does not own) the renewable energy certificates or "green tags" associated with certain projects in its resource portfolio, using the proceeds to benefit customers, we are not permitted to say the electricity from those projects is delivered to customers.

500-kilovolt Transmission Projects

Boardman to Hemingway

At the end of 2014, we achieved a major milestone in one of Idaho Power's two planned 500-kilovolt (kV) projects, the 300-mile Boardman to Hemingway line. On Dec. 19, 2014, the Bureau of Land Management (BLM) released the draft Environmental Impact Statement (EIS) for the project. This milestone is the culmination of years of hard work, and continues a trend of positive forward momentum for the project.

Idaho Power is the project manager. The company entered a joint funding agreement with PacifiCorp and the Bonneville Power Administration in January 2012 for project permitting costs. Idaho Power's estimated cost of the permitting phase is $35 million, including allowance for funds used during construction (AFUDC), and its share of the project is 21 percent.

Currently, the in-service date for the project is 2021 or beyond.

Gateway West

Idaho Power and PacifiCorp are jointly proposing and developing the 1,000-mile, 500-kV Gateway West transmission project. PacifiCorp is the project manager and Idaho Power's interest in the project is for four of 10 segments. Idaho Power has a 33 percent interest in permitting three of the four segments, and a 100 percent interest in the fourth.

The BLM released its final EIS for the project in April 2013, and record of decision in November 2013 (both also excluding segments 8 and 9). The BLM estimates it will publish a record of decision on segments 8 and 9 during 2016.

Near Warm Lake, Idaho

Public Utility Regulatory Policies Act (PURPA)

This federal law, enacted in 1978 following the national energy crisis, requires Idaho Power to buy energy from qualified renewable energy projects. As of Jan. 15, 2015, the company had contracts with private developers for more than 460 MW of new solar generation, with more projects being proposed. Projects already under contract represent energy costs of approximately $1.6 billion in guaranteed 20-year contracts.

Idaho Power is required to buy this energy even if we already have more than our customers need. Any additional energy costs are paid by customers through higher rates. It also increases the likelihood that Idaho Power will at times be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss.

Idaho Power is asking the Idaho Public Utilities Commission (IPUC) to allow for a 2-year term on future utility scale contracts. Idaho Power will still be required to purchase the power, but Idaho Power's proposal would allow prices to be adjusted periodically to reflect actual and evolving market conditions.

Safety

Among the lowest carbon-emitting utilities in the country

Emissions Reduction

Since 2009, Idaho Power has voluntarily reduced our company's carbon (CO_2) output per MW below 2005 levels. The company remained on target to meet its goal to reduce CO_2 emissions intensity by 10 to 15 percent below 2005 emissions for the six-year period 2010 through 2015. We are among the lowest carbon-emitting utilities in the country, and we will continue to work to responsibly reduce our carbon footprint.

Capital Expenditures

IDACORP continues to advance a sizable capital investment strategy, including continuing upgrades to Idaho Power's infrastructure. Currently, we forecast approximately $300 million annually in capital expenditures from 2015 to 2019. Recent infrastructure investments and future anticipated infrastructure projects are intended to help Idaho Power provide reliable service to existing customers and meet projected customer growth.

Idaho Power's noteworthy capital projects include the replacement of aging assets, upgrades to generation plants, a 17-year project begun in 2013 to replace seven-million feet of underground cable, ongoing system upgrades, and continued progress on the two 500-kV transmission lines. As of the date of this report, Idaho Power estimates total capital expenditures of approximately $1.5 billion over the next five years.

2015 Integrated Resource Plan (IRP)

Idaho Power's biennial IRP identifies the most cost-effective and responsible ways to provide for future customer demand for electricity. Preparation of the 2015 IRP began in August 2014 and is expected to be completed during the second quarter of 2015.

One of the first tasks was updating load forecast assumptions for the next 20 years. Based on that update, Idaho Power expects the 2015 IRP to reflect a slight increase in the average and peak load growth rates from those in the 2013 IRP.

Swan Falls Dam

Boise, Idaho

A Strong Regulatory Framework

Idaho Power has achieved constructive regulatory outcomes through a productive, multi-pronged strategy. This includes general rate cases, subject-specific rate filings, tariff riders and cost recovery mechanisms that share risks and benefits between Idaho Power customers and our owners.

Extension of Settlement Stipulation

One of the most notable regulatory developments during 2014 was the IPUC's October 2014 approval of a regulatory settlement stipulation extending, with modifications, a December 2011 agreement permitting Idaho Power to amortize additional ADITCs to help achieve a minimum 9.5 percent Idaho-jurisdictional return on year-end equity in 2012, 2013 and 2014.

The October 2014 settlement stipulation allows for Idaho Power's amortization of up to a total of $45 million of additional ADITCs for the period from 2015 to 2019 to help achieve a minimum 9.5 percent Idaho ROE for an applicable year. Like the December 2011 agreement, the new settlement stipulation provides for sharing of Idaho-jurisdictional earnings between Idaho Power and Idaho customers.

Strength

Lower cost per kilowatt-hour compared to U.S. residential average

Fixed Cost Adjustment and Power Cost Adjustment

On May 30, 2014, the IPUC issued its orders approving our company's annual Fixed Cost Adjustment (FCA) and Power Cost Adjustment (PCA) filings.

The FCA is a true-up mechanism that decouples energy sales from revenue to remove the financial disincentives that exist when the company invests in demand-side management resources.

The 2014 FCA collected $6.0 million more than the 2013 FCA balance, resulting in a 1.17 percent increase for Idaho residential customers and a 1.20 percent increase for Idaho Small General Service customers.

The PCA is a cost recovery mechanism that passes on both the benefits and costs of supplying energy to Idaho Power customers. The net impact of the 2014 PCA was an increase of $11.1 million, or approximately 1 percent overall.

Net Power Supply Expenses

Another item that illustrates Idaho Power's active approach to regulatory matters is the IPUC's approval of Idaho Power's request for an increase of approximately $99 million in the normalized or "base level" Idaho-jurisdiction power supply expense to be used in the determination of the Idaho PCA rate. While the May 2014 IPUC approval of the application results in no net change in the amount collected through base rates and the PCA mechanism in the aggregate, approval of the application will decrease the amount of any base rate increase requested in Idaho Power's next general rate case application.

Low Rates for Customers

Idaho Power works hard to keep electricity prices fair, just and reasonable. The company is proud to point out that it continues to have some of the lowest rates in the nation for retail customers. July 2014 Edison Electric Institute data shows Idaho Power residential customers pay $105.26 per 1,000 kilowatt-hours, compared to the U.S. residential average of $138.10.

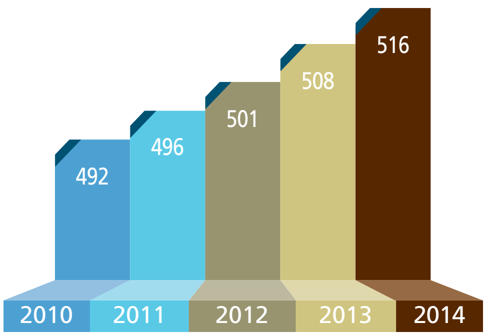
McCall, Idaho

Stability

Hailey, Idaho

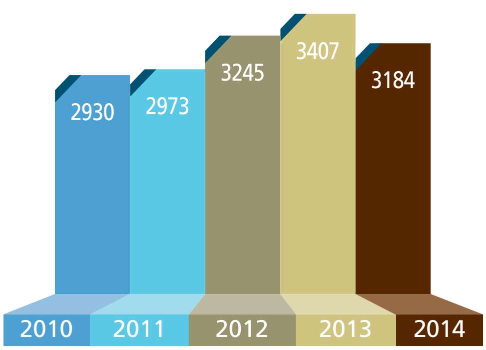
Customer, Load and Rate Base Growth Opportunities

In recent years, Idaho Power has seen positive growth in its customer count and associated positive impacts on Idaho Power's revenue. At the same time Idaho Power pursues customer growth, it is also responsibly planning for that growth.



General Business Customers

(at Dec. 31, 2014) Thousands



Idaho Power System Peaks

in Megawatts

The total number of people employed in Idaho Power's service area in December 2014 was more than 459,000. Several nationally known businesses, including Chobani and Clif Bar, have recently chosen to site large new facilities in Idaho, due in part to fair-priced energy and Idaho Power's outreach in partnership with local and state economic development agencies.

Customer and Revenue Growth

Idaho Power customer count is continuing its upward trend. From 2013 to 2014 it increased 1.4 percent, or 7,328 customers. The company had approximately 516,000 general business customers as of Dec. 31, 2014.

Idaho Power's most recent load forecast predicts a 1.4 percent five-year compound annual growth rate in residential loads and a 2.1 percent five-year compound annual growth rate in residential customers.

Favorable Economic Activity and Development

To encourage responsible and sustainable growth, Idaho Power actively participates in and supports state and local economic development initiatives. Visible economic activity in Idaho Power's service area and the state as a whole is yet another sign of an economy on the upswing.

A number of businesses have recently constructed, or are in the process of constructing, sizable facilities in Idaho Power's service area. Some projects include large facilities for Clif Bar, natural food company Amy's Kitchen and a potential $1.5 billion fertilizer plant. The tech industry has also identified Idaho as a favorable place to do business: a cloud computing company data center is in process, and Internet company Fiberpipe is permitting a 70,000-square-foot facility.

IDACORP and Idaho Power Board of Directors (as of Feb. 19, 2015)

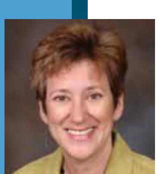
Robert A. Tinstman*
(1999) Boise, Idaho
Director, Primoris Services Corp.; Home Federal Bancorp, Inc.; former Director of CNA Surety Corp.; and formerly President and Chief Executive Officer of Morrison-Knudsen Corporation.

Darrel T. Anderson
(2013) Boise, Idaho
President and Chief Executive Officer of IDACORP, Inc. and Idaho Power.

Thomas E. Carlile
(2014) Boise, Idaho
Chief Executive Officer and Director of Boise Cascade Company since 2013; Director of Boise Cascade Holdings, LLC and Forest Products Holdings LLC; former Chief Executive Officer and Director of Boise Cascade LLC, 2009–2013; former Executive Vice President and Chief Financial Officer of Boise Cascade LLC, 2008–2009.

Richard J. Dahl
(2008) Kapolei, Hawaii
Chairman of the Board, President and Chief Executive Officer of James Campbell Company, LLC; Chairman of the Board, International Rectifiers Corp; Director, DineEquity, Inc.; and formerly President and Chief Operating Officer of Dole Food Company.

Ronald W. Jibson
(2013) North Salt Lake, Utah
President, Chief Executive Officer and Director, Questar Corporation; President and Chief Executive Officer of Wexpro Corporation; and President and Chief Executive Officer of Questar Gas Company; Director and Chairman of the Board of Questar Pipeline Company.



Judith A. Johansen
(2007) Lake Oswego, Oregon
Director, Pacific Continental Corp., Pacific Continental Bank, Schnitzer Steel and Roseburg Forest Products; formerly President of Marylhurst University; formerly President and Chief Executive Officer of PacifiCorp; and formerly Chief Executive Officer and Administrator of Bonneville Power Administration.

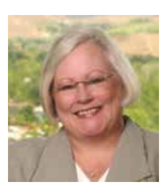
Dennis L. Johnson
(2013) Eagle, Idaho
President, Chief Executive Officer and Director of United Heritage Mutual Holding Company, United Heritage Financial Group, and United Heritage Life Insurance Company.

J. LaMont Keen
(2004) Boise, Idaho
Former President and Chief Executive Officer, IDACORP, Inc. and Idaho Power Company; Director of Cascade Bancorp.

Christine King
(2006) Scottsdale, Arizona
Director, QLogic Corp., Cirrus Logic, Inc., Skyworks Solutions, Inc.; former Director of Atheros Communications, Inc., Open-Silicon, Inc., and Standard Microsystems Corporation; formerly President and Chief Executive Officer of Standard Microsystems Corporation; and formerly President and Chief Executive Officer of AMI Semiconductor.

Richard J. Navarro
(2015) Boise, Idaho
Formerly Chief Financial Officer of Albertson's, LLC; formerly Senior Vice President and Controller at Albertson's, Inc.; former director of TitleOne Corporation and the Boise State University Foundation.

Jan B. Packwood**
(1997) Boise, Idaho
Formerly President and Chief Executive Officer of IDACORP, Inc.; Director of Westmoreland Coal Company.



Joan H. Smith**
(2004) Portland, Oregon
Self-employed consultant, consulting on regulatory strategy and telecommunications; formerly Oregon Public Utility Commissioner.

Thomas J. Wilford**
(2004) Boise, Idaho
Formerly President of Alscott, Inc.; formerly Chief Executive Officer of J.A. and Kathryn Albertson Foundation, Inc.; formerly Director, K12, Inc.

( ) year appointed or elected to the board
* Chairman of the Board
** Will retire as a Director immediately prior to the 2015 Annual Meeting of shareholders

IDACORP and Idaho Power Officers
(as of Feb. 19, 2015)

IDACORP and Idaho Power

Darrel T. Anderson (19)
President and Chief Executive Officer, IDACORP, Inc. and Idaho Power

Rex Blackburn (7)
Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power

Patrick A. Harrington (29)
Corporate Secretary, IDACORP, Inc. and Idaho Power

Steven R. Keen (32)
Senior Vice President, Chief Financial Officer and Treasurer, IDACORP, Inc. and Idaho Power

Jeffrey Malmen (7)
Vice President, Public Affairs, IDACORP, Inc. and Idaho Power

Daniel B. Minor (29)
Executive Vice President, IDACORP, Inc. and Executive Vice President and Chief Operating Officer, Idaho Power

Ken W. Petersen (16)
Vice President, Corporate Controller and Chief Accounting Officer, IDACORP, Inc. and Idaho Power

Lori D. Smith (31)
Vice President and Chief Risk Officer, IDACORP, Inc. and Idaho Power

Idaho Power

Lisa A. Grow (27)
Senior Vice President, Power Supply

Warren Kline (41)
Senior Vice President, Customer Operations

Lonnie Krawl (9)
Vice President and Chief Information Officer

Luci K. McDonald (10)
Vice President, Human Resources and Corporate Services

N. Vern Porter (25)
Vice President

Gregory W. Said (34)
Vice President, Regulatory Affairs

( ) years of service

Darrel Anderson   Daniel Minor

Southern Idaho desert

Conclusion

Strength, stability, security and safety aren't just words at IDACORP, they're touchstones. We work to achieve those standards every day for our company and you, our owners.

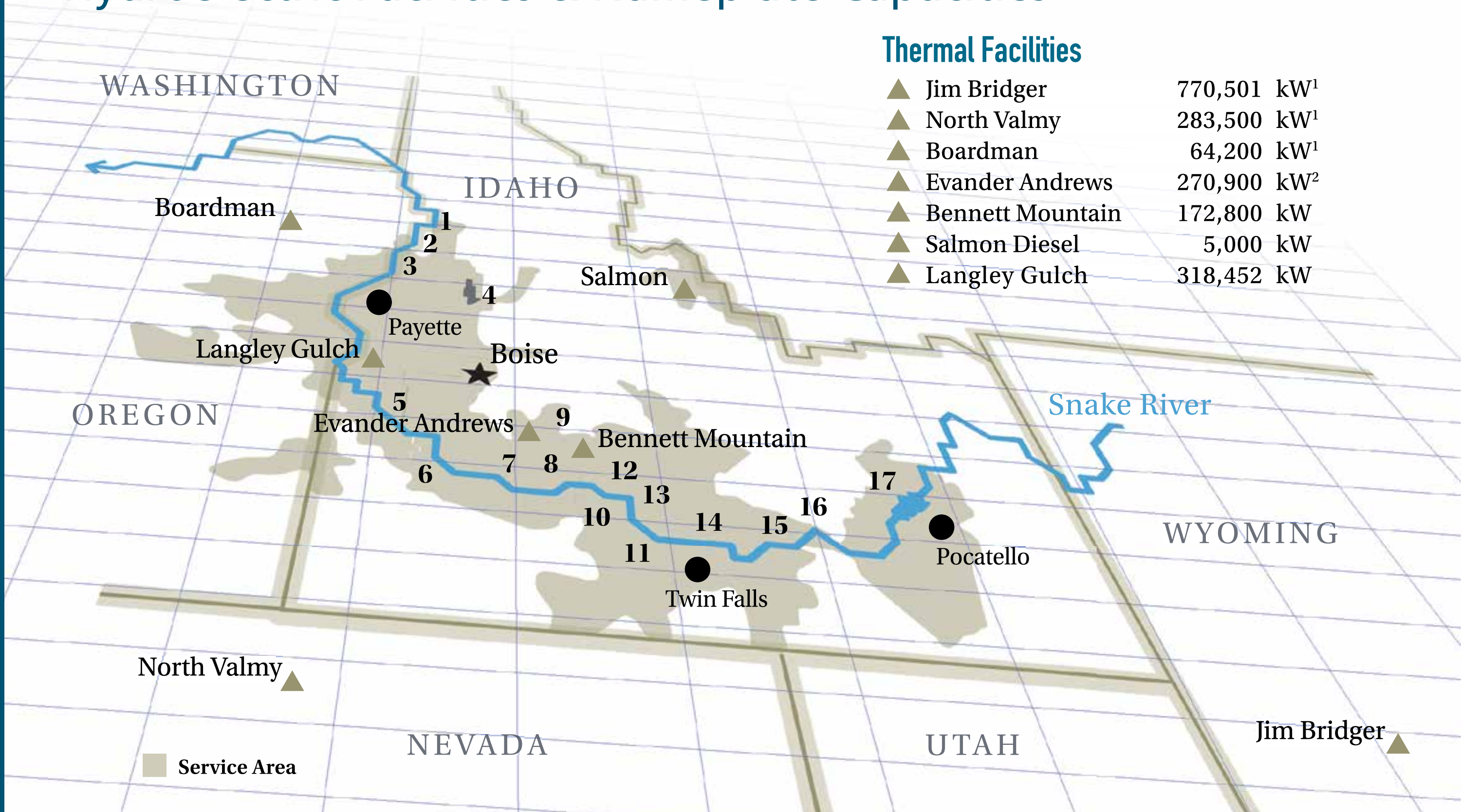
Thanks to Idaho Power's solid foundation of nearly 100 years as a fully integrated electric utility, and our longtime commitment to maximizing our clean, low-cost hydroelectric generation resources, IDACORP remains strong now, and looks forward to a bright future.

We thank you for putting your trust in our company, today and tomorrow.

Hydroelectric Facilities & Nameplate Capacities

Thermal Facilities

Jim Bridger	770,501 kW[1]
North Valmy	283,500 kW[1]
Boardman	64,200 kW[1]
Evander Andrews	270,900 kW[2]
Bennett Mountain	172,800 kW
Salmon Diesel	5,000 kW
Langley Gulch	318,452 kW



Hydroelectric Facilities

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	585,400 kW
4	Cascade	12,420 kW
5	Swan Falls	27,170 kW
6	C.J. Strike	82,800 kW
7	Bliss	75,000 kW
8	Lower Malad	13,500 kW
9	Upper Malad	8,270 kW
10	Lower Salmon	60,000 kW
11	Upper Salmon	34,500 kW
12	Thousand Springs	8,800 kW
13	Clear Lake	2,500 kW
14	Shoshone Falls	12,500 kW
15	Twin Falls	52,897 kW
16	Milner	59,448 kW
17	American Falls	92,340 kW

[1] Idaho Power share [2] Danskin

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2014

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

State of incorporation: Idaho

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:	Name of exchange on which registered
IDACORP, Inc.: Common Stock, without par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes (X) No ( )

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

IDACORP, Inc.	Yes	(X)	No	( )	Idaho Power Company	Yes	(X)	No	( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.

IDACORP, Inc.:

Large accelerated filer	(X)	Accelerated filer	( )	Non-accelerated filer	( )	Smaller reporting company	( )

Idaho Power Company:

Large accelerated filer	( )	Accelerated filer	( )	Non-accelerated filer	(X)	Smaller reporting company	( )

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc.	Yes	( )	No	(X)	Idaho Power Company	Yes	( )	No	(X)

Aggregate market value of voting and non-voting common stock held by non-affiliates (June 30, 2014):

IDACORP, Inc.:	$ 2,875,967,074	Idaho Power Company:	None

Number of shares of common stock outstanding as of February 13, 2015:

IDACORP, Inc.:	50,259,292
Idaho Power Company:	39,150,812, all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14	Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders.

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

TABLE OF CONTENTS

* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2015 annual meeting of shareholders.

COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are commonly used or found in multiple locations in this report:

ADITC	Accumulated Deferred Investment Tax Credits
AFUDC	Allowance for Funds Used During Construction
APCU	Annual Power Cost Update
BACT	Best Available Control Technology
BCC	Bridger Coal Company, a joint venture of IERCo
BLM	U.S. Bureau of Land Management
BPA	Bonneville Power Administration
CAA	Clean Air Act
CAMP	Comprehensive Aquifer Management Plan
CO_2	Carbon Dioxide
CWA	Clean Water Act
EGUs	Electric Utility Generating Units
EIS	Environmental Impact Statement
EPA	U.S. Environmental Protection Agency
EPS	Earnings Per Share
ESA	Endangered Species Act
FCA	Fixed Cost Adjustment
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GAAP	Generally Accepted Accounting Principles
GHG	Greenhouse Gas
HAPS	Hazardous Air Pollutants
HCC	Hells Canyon Complex
Ida-West	Ida-West Energy, a subsidiary of IDACORP, Inc.
Idaho ROE	Idaho-jurisdiction return on year-end equity
IERCo	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IESCo	IDACORP Energy Services Co., a subsidiary of IDACORP, Inc.
IFS	IDACORP Financial Services, Inc., a subsidiary of IDACORP, Inc.
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
IRS	U.S. Internal Revenue Service
kW	Kilowatt
MATS	Mercury and Air Toxics Standards
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NMFS	National Marine Fisheries Service
NOx	Nitrogen Oxide
NSPS	New Source Performance Standards
NSR/PSD	New Source Review / Prevention of Significant Deterioration
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCA	Power Cost Adjustment
PCAM	Oregon Power Cost Adjustment Mechanism
PURPA	Public Utility Regulatory Policies Act of 1978
REC	Renewable Energy Certificate
RPS	Renewable Portfolio Standard
SEC	U.S. Securities and Exchange Commission
SMSP	Security Plan for Senior Management Employees
SO_2	Sulfur Dioxide
USFWS	U.S. Fish and Wildlife Service
VIEs	Variable Interest Entities

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations, such as statements regarding projected or future financial performance, cash flows, capital expenditures, dividends, capital structure or ratios, strategic goals, challenges, objectives, and plans for future operations. Such statements constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, or future events or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue," or similar expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Part I, Item 1A - “Risk Factors” and Part II, Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations" of this report, as well as in subsequent reports filed by IDACORP and Idaho Power with the Securities and Exchange Commission, and the following important factors:

- the effect of decisions by the Idaho and Oregon public utilities commissions, the Federal Energy Regulatory Commission, and other regulators that impact Idaho Power's ability to recover costs and earn a return;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, and the availability and use of demand-side management programs, and their associated impacts on loads and load growth;
- the impacts of changes in economic conditions, including the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and collections of receivables;
- unseasonable or severe weather conditions, wildfires, drought, and other natural phenomena and natural disasters, which affect customer demand, hydroelectric generation levels, repair costs, and the availability and cost of fuel for generation plants or purchased power to serve customers;
- advancement of technologies that reduce loads or reduce the need for Idaho Power's generation of electric power;
- adoption of, changes in, and costs of compliance with, laws, regulations, and policies relating to the environment, natural resources, and endangered species, and the ability to recover those costs through rates;
- the ability to obtain debt and equity financing or refinance existing debt when necessary or advisable and on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets, interest rate fluctuations, decisions by the Idaho or Oregon public utility commissions, and the companies' past or projected financial performance;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to credit and contractual arrangements;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River basin, which may impact the amount of generation from Idaho Power's hydroelectric facilities;
- the ability to purchase fuel and power on favorable payment terms and prices, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires, explosions, and mechanical breakdowns that may occur while operating and maintaining an electric system, which can cause unplanned outages, reduce generating output, damage the companies’ assets, operations, or reputation, subject the companies to third-party claims for property damage, personal injury, or loss of life, or result in the imposition of civil, criminal, or regulatory fines or penalties;
- the ability to buy and sell power, transmission capacity, and fuel in the markets;
- the ability to enter into financial and physical commodity hedges with creditworthy counterparties to manage price and commodity risk, and the failure of any such risk management and hedging strategies to work as intended;
- administration of Federal Energy Regulatory Commission and other mandatory reliability, security, and other requirements for system infrastructure, which could result in penalties and increase costs;
- disruptions or outages of Idaho Power's generation or transmission systems or of any interconnected transmission system;

- the increased costs and operational challenges associated with purchasing and integrating intermittent renewable energy sources, including mandated power purchases under federal law, into Idaho Power's resource portfolio;
- changes in actuarial assumptions, changes in interest rates, and the return on plan assets for pension and other post-retirement plans, which can affect future pension and other postretirement plan funding obligations, costs, and liabilities;
- the ability to continue to pay dividends based on financial performance, and in light of contractual covenants and restrictions and regulatory limitations;
- changes in tax laws or related regulations or new interpretations of applicable laws by federal, state, or local taxing jurisdictions, the availability of tax credits, and the tax rates payable by IDACORP shareholders on common stock dividends;
- employee workforce factors, including the operational and financial costs of unionization or the attempt to unionize all or part of the companies' workforce, the impact of an aging workforce and retirements, the cost and ability to retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, which may result in penalties and fines and increase the cost of compliance, the nature and extent of investigations and audits, and the cost of remediation;
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement new technology solutions;
- the inability to obtain or cost of obtaining and complying with required governmental permits and approvals, licenses, rights-of-way, and siting for transmission and generation projects and hydroelectric facilities;
- the cost and outcome of litigation, dispute resolution, and regulatory proceedings, and the ability to recover those costs or the costs of operational changes through insurance or rates, or from third parties;
- the failure of information systems or the failure to secure information system data, failure to comply with privacy laws, security breaches, or the direct or indirect effect on the companies' business or operations resulting from cyber attacks, terrorist incidents or the threat of terrorist incidents, and acts of war; and
- adoption of or changes in accounting policies and principles, changes in accounting estimates, and new Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations of existing requirements.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

PART I
ITEM 1. BUSINESS

OVERVIEW

Background

IDACORP, Inc. (IDACORP) is a holding company incorporated in 1998 under the laws of the state of Idaho. Its principal operating subsidiary is Idaho Power Company (Idaho Power). IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions with access to books and records and imposes record retention and reporting requirements on IDACORP.

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as the successor to a Maine corporation that was organized in 1915 and began operations in 1916. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and capacity and is regulated by the state regulatory commissions of Idaho and Oregon and by the FERC. 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. Idaho Power's utility operations constitute nearly all of IDACORP's current business operations and are IDACORP’s only reportable business segment. Segment financial information is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2014, IDACORP had 2,021 full-time employees, 2,011 of whom were employed by Idaho Power, and 22 part-time employees, 20 of whom were employed by Idaho Power.

IDACORP’s other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), the successor to IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003.

IDACORP’s and Idaho Power’s principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

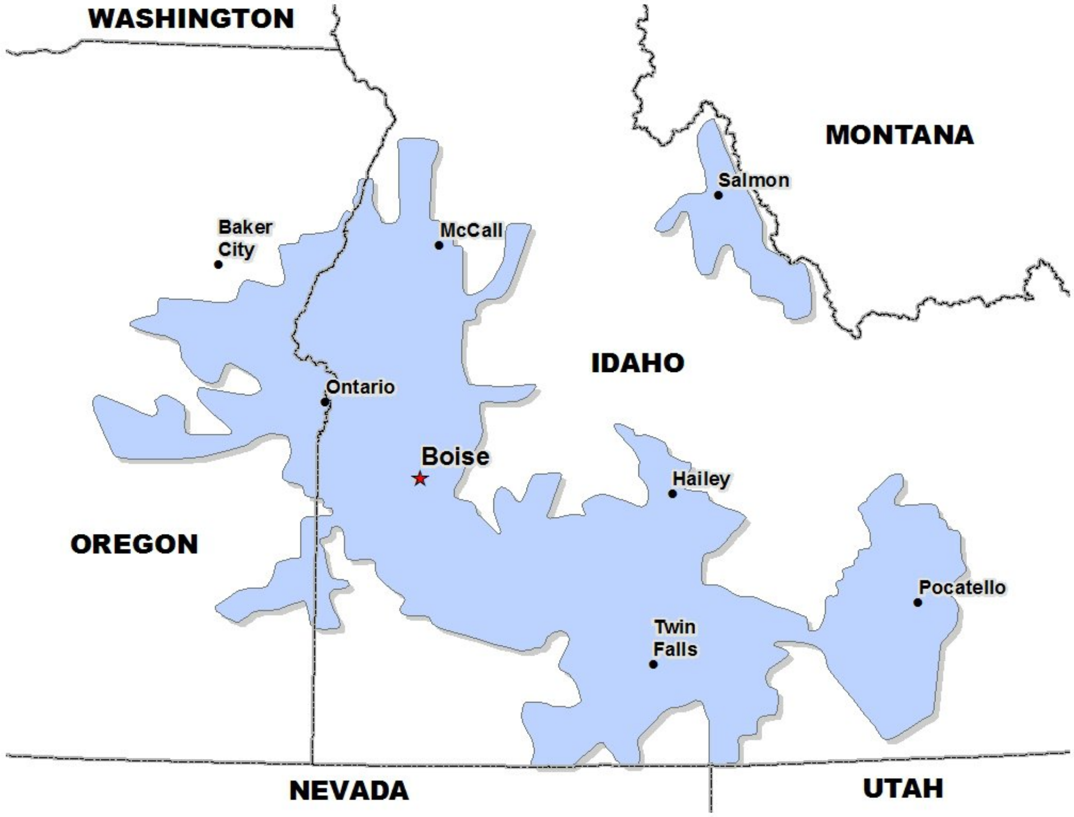
Available Information

IDACORP and Idaho Power make available free of charge on their websites their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is *www.idacorpinc.com* and Idaho Power's website is *www.idahopower.com*. The contents of these websites are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC’s website, *www.sec.gov*, or from the SEC’s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

UTILITY OPERATIONS

Background

Idaho Power provided electric utility service to approximately 516,000 general business customers in southern Idaho and eastern Oregon as of December 31, 2014. Over 428,000 of these customers are residential. Idaho Power’s principal commercial and industrial customers are involved in food processing and refining, electronics and general manufacturing, agriculture, health care, and winter recreation. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 71 cities in Idaho and nine cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 25 counties in Idaho and three counties in Oregon. Idaho Power's service area is shaded in the illustration on the following page and covers approximately 24,000 square miles with an estimated population of one million.



Electric utilities have historically been recognized as natural monopolies and operate in a highly regulated environment - one in which they have an obligation to provide electric service to their customers and in return receive an exclusive franchise within their service territory - with an opportunity to earn a regulated rate of return. Idaho Power is under the jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC), the Public Utility Commission of Oregon (OPUC), and the FERC. The IPUC and OPUC determine the rates that Idaho Power is authorized to charge to its general business customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. As a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its open access transmission tariff (OATT). Additionally, the FERC has jurisdiction over Idaho Power's sales of transmission capacity and wholesale electricity, hydroelectric project relicensing, and system reliability, among other items.

Regulatory Accounting

Idaho Power is subject to accounting principles generally accepted in the United States of America, with the impacts of rate regulation reflected in its financial statements. These principles provide for the deferral as regulatory assets of certain costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain credits that would otherwise reduce expense or increase revenues can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. Idaho Power records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

Business Strategy

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business, as Idaho Power's utility operations are the primary driver of IDACORP's operating results. Idaho Power's three-part strategy can be summarized as follows:

- ***Responsible Planning***: Idaho Power’s planning process is intended to ensure adequate generation, transmission, and distribution resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power’s regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.

- ***Responsible Development and Protection of Resources***: Idaho Power's business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural resources upon which Idaho Power and the communities it serves depend. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.
- ***Responsible Energy Use***: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions, as well as operating Idaho Power's system in a manner that extracts additional value through changes in fuel mix and generation.

Idaho Power regularly evaluates and refines its business strategy to ensure coordination among and integration of all functional areas of the company. Idaho Power's business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company's financial stability and flexibility.

Rates and Revenues

Idaho Power generates revenue primarily through the sale of electricity to retail and wholesale customers and the provision of transmission service. The prices that the IPUC, the OPUC, and the FERC authorize Idaho Power to charge for the electric power and services Idaho Power sells are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. In addition to the discussion below, for more information on Idaho Power's regulatory framework and rate regulation, see the "Regulatory Matters" section of Part II, Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) and Note 3 – "Regulatory Matters" to the consolidated financial statements included in this report.

Retail Rates**:** Idaho Power periodically evaluates the need to seek changes to its retail electricity price structure to cover its operating costs and provide an opportunity for a reasonable rate of return on its investments. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA) mechanism, balancing accounts and tariff riders, and subject-specific filings to recover its costs of providing service and to earn a return on investment. Retail prices are generally determined through formal ratemaking proceedings that are conducted under established procedures and schedules before the issuance of a final order. Participants in these proceedings include Idaho Power, the staffs of the IPUC or OPUC, and other interested parties. The IPUC and OPUC are charged with ensuring that the prices and terms of service are fair, are non-discriminatory, and provide Idaho Power an opportunity to recover its prudently incurred or allowable costs and expenditures and earn a reasonable return on investment. The ability to request rate changes does not, however, ensure that Idaho Power will recover all of its costs or earn a specified rate of return.

In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific authorization from the IPUC or OPUC. Deferred amounts are generally collected from or refunded to retail customers through the use of base rates or supplemental tariffs. Outside of base rates, three of the most significant mechanisms for recovery of costs are the PCA mechanisms, FCA mechanism, and energy efficiency rider. The Idaho and Oregon PCA mechanisms are intended to address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers by allowing partial recovery of the difference between net power supply costs included in base rates and actual net power supply costs incurred by Idaho Power. The FCA mechanism is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge for certain Idaho customer classes and linking it instead to a set amount per customer. Separately, Idaho Power collects some of its energy efficiency program costs through an energy efficiency rider on customer bills.

Wholesale Markets**:** As a public utility subject to the provisions of Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its OATT. Idaho Power's OATT transmission rate is revised each year based primarily on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power participates in the wholesale energy markets by purchasing power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans. These operating plans are impacted by factors such as customer demand for power, market prices, generating costs, transmission constraints, and availability of generating resources. Some of Idaho Power's 17 hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric generation units and when to store water in reservoirs. Idaho Power at times operates these and its other generation facilities to take advantage of market opportunities. These decisions affect the timing and volumes of market purchases and market sales. Even in below-normal water years, there are opportunities to vary water usage to capture wholesale marketplace economic benefits, maximize generation unit efficiency and meet peak loads. Compliance factors such as allowable river stage elevation changes and flood control requirements also influence these generation dispatch decisions. Idaho Power's off-system sales revenues depend largely on the availability of generation resources above the amount necessary to serve customer loads as well as adequate market power prices at the time when those resources are available. When either factor is low, off-system sales revenue is reduced.

Energy Sales: Weather, seasonal customer demand, and economic conditions all impact the amount of electricity that Idaho Power sells as well as the costs it incurs to provide that electricity. Idaho Power's utility revenues are not earned and associated expenses are not incurred evenly during the year. Idaho Power’s retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps. The table that follows presents Idaho Power’s revenues and sales volumes for the last three years, classified by customer type. Approximately 95 percent of Idaho Power’s general business revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power’s operations, including information on energy sales, are discussed further in Part II, Item 7 - MD&A - "Results of Operations - Utility Operations.”

	Year Ended December 31,		
	2014	**2013**	**2012**
General business revenues (thousands of dollars)			
Residential	$ 500,195	$ 513,914	$ 431,555
Commercial	299,462	281,009	241,519
Industrial	182,675	165,941	145,054
Irrigation	158,654	159,242	137,424
Provision for rate refund for sharing mechanism	(7,999)	(7,602)	(7,151)
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,706)	(10,776)	(10,636)
Total general business revenues	1,122,281	1,101,728	937,765
Off-system sales	77,165	54,473	61,534
Other	79,205	86,897	77,426
Total revenues	$ 1,278,651	$ 1,243,098	$ 1,076,725
Energy sales (thousands of MWh)			
Residential	4,965	5,365	5,039
Commercial	3,944	3,975	3,865
Industrial	3,217	3,182	3,133
Irrigation	1,966	2,097	2,048
Total general business	14,092	14,619	14,085
Off-system sales	2,220	1,683	2,183
Total	16,312	16,302	16,268

Competition: Idaho Power's electric utility business has historically been recognized as a natural monopoly. Idaho Power's rates for retail electric services are generally determined on a “cost of service” basis. Rates are designed to provide, after recovery of allowable operating expenses including depreciation on capital investments, an opportunity for Idaho Power to earn a reasonable return on investment as authorized by regulators. Alternative methods of generation, including customer-owned solar and other forms of distributed generation, compete with Idaho Power for sales to existing customers. Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that could alter demand for Idaho Power's electric energy. Idaho Power also competes with natural gas distribution companies in serving the energy needs of customers for space heating, water heating, and appliances, and with fuel oil providers for space heating.

Idaho Power also participates in the wholesale energy markets and in the electric transmission markets. Generally, these wholesale markets are regulated by the FERC, which requires electric utilities to transmit power to or for wholesale purchasers and sellers and make available, on a non-discriminatory basis, transmission capacity for the purpose of providing these services.

Power Supply

Overview: Idaho Power primarily relies on company-owned hydroelectric, coal-fired, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Market purchases and sales are used to supplement Idaho Power's generation and balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, economic conditions, and availability of generation resources impact power supply costs. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River basin. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and wholesale market purchased power. Economic conditions and governmental regulations can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power. Idaho Power has PCA mechanisms in Idaho and Oregon that mitigate in large part the potentially adverse financial statement impacts of volatile fuel and power costs.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand was 3,407 Megawatts (MW), set on July 2, 2013, and the all-time winter peak demand was 2,527 MW, set on December 10, 2009. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. The table below presents Idaho Power's total power supply for the last three years:

	MWh			**Percent of Total Generation**		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
	(thousands of MWh)					
Hydroelectric plants	6,170	5,656	7,956	47%	42%	57%
Coal-fired plants	5,851	6,327	5,227	44%	47%	38%
Natural gas fired plants	1,175	1,576	676	9%	11%	5%
Total system generation	13,196	13,559	13,859	100%	100%	100%
Purchased power - cogeneration and small power production	2,286	2,127	1,961			
Purchased power - other	1,867	1,775	1,709			
Total purchased power	4,153	3,902	3,670			
Total power supply	17,349	17,461	17,529			

***Hydroelectric Generation*:** Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation of approximately 8.5 million Megawatt-hours (MWh) under median water conditions. The amount of hydroelectric power generated depends on several factors—the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall, the amount and timing of water leases, and other weather and stream flow considerations. Generation at the plants located on the Snake River also depends on the state water rights held by Idaho Power and the long-term sustainability of the Snake River, tributary spring flows, and the Eastern Snake Plain Aquifer that is connected to the Snake River. Idaho Power participates in work groups related to water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River.

During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced, resulting in a reliance on other generation resources and power purchases. In 2013, below average snow accumulation in the Snake River basin resulted in hydroelectric generation below the 8.5 million MWh historical median. For 2014, significantly low upstream carryover storage hindered the impact of the runoff of near-normal 2014 snow accumulation, resulting in 2014 generation below the historical median. Generation from Idaho Power's hydroelectric facilities was 6.2

million MWh in 2014. The Northwest River Forecast Center of the National Oceanic and Atmospheric Administration reported that Brownlee Reservoir (part of Idaho Power's Hells Canyon Complex) inflow for April through July 2014 was 3.4 million acre-feet (maf). By comparison, April through July Brownlee Reservoir inflow was 2.6 maf in 2013 and 5.5 maf in 2012. For 2015, Idaho Power estimates generation from its hydroelectric facilities of between 7.0 million MWh and 9.0 million MWh.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental issues. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex project, its largest hydroelectric generation source. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power’s Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects.”

Idaho Power is subject to the provisions of the FPA as a “public utility” and as a “licensee” by virtue of its hydroelectric operations. As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described in the FPA and related FERC regulations. These conditions and regulations include, among other items, provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, and possible takeover of a project after expiration of its license upon payment of net investment and severance damages.

Coal-Fired Generation**:** Idaho Power co-owns the following coal-fired power plants:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- North Valmy located in Nevada, in which Idaho Power has a 50 percent interest; and
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest.

PacifiCorp is the operator of the Jim Bridger power plant. Idaho Power owns a one-third interest in BCC, which owns the mine that supplies coal to the Jim Bridger power plant. The mine, which is operated by PacifiCorp and located near the Jim Bridger plant, operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface and underground sources. Idaho Power believes that BCC has sufficient reserves to provide coal deliveries for at least the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2017 from the Black Butte Coal Company’s Black Butte mine located near the Jim Bridger plant. This contract supplements the BCC deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant’s rail load-in facility and unit coal train, while limited, provides the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

NV Energy is the operator of the North Valmy power plant. NV Energy and Idaho Power have contracts with a coal supplier through 2015. Idaho Power's share of these contracts along with existing coal inventory at the plant are expected to meet Idaho Power's projected coal supply needs for 2015 and approximately 60 percent of its supply needs for 2016.

Portland General Electric Company is the operator of the Boardman power plant. Ninety percent of the Boardman plant’s projected coal requirement is under contract for 2015. The Boardman generating plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

Natural Gas-fired Generation**:** Idaho Power owns and operates the Langley Gulch natural gas-fired combined cycle power plant and the Danskin and Bennett Mountain natural gas-fired simple cycle combustion turbine power plants. All three plants are located in Idaho. The Langley Gulch power plant was placed into service in June 2012.

Idaho Power operates the Langley Gulch plant as a baseload unit and the Danskin and Bennett Mountain plants to meet peak supply needs. The plants are also used to take advantage of wholesale market opportunities. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is transported through the Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. These transportation agreements vary in contract length, with the latest termination date of May 2042, but with extensions at Idaho Power’s discretion. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. This firm storage contract expires in 2043. Idaho Power purchases and stores natural gas with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

As of December 31, 2014, approximately 5.35 million MMBtu's of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through July 2015. Idaho Power plans to manage the procurement of additional natural gas for the peaking units on the daily spot market or from storage inventory as necessary to meet system requirements and fueling strategies.

***Purchased Power*:** As described below, Idaho Power purchases power in the wholesale market as well as power pursuant to long-term power purchase contracts and exchange agreements.

Wholesale Market Transactions: To supplement its self-generated power and long-term purchase arrangements, Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk management policy limitations, and unit availability. Depending on availability of excess power or generation capacity, pricing, and opportunities in the markets, Idaho Power also sells power in the wholesale markets.

During 2014 and 2013, Idaho Power purchased 1.9 million MWh and 1.8 million MWh of power through wholesale market purchases at an average cost of $49.31 per MWh and $47.91 per MWh, respectively. During 2014 and 2013, Idaho Power sold 2.2 million MWh and 1.7 million MWh of power in wholesale market sales, with an average price of $34.76 per MWh and $32.37 per MWh, respectively.

Long-term Power Purchase and Exchange Arrangements: In addition to its wholesale market purchases, Idaho Power has the following notable firm long-term power purchase contracts and energy exchange agreements:

- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through 2033.
- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.
- USG Oregon LLC - for 22 MW (estimated average annual output) from the Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is through 2037.
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock hydroelectric project in southern Idaho in exchange for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

PURPA Power Purchase Contracts: Idaho Power purchases power from PURPA projects as mandated by federal law. As of December 31, 2014, Idaho Power had contracts with on-line PURPA-related projects with a total of 781 MW nameplate generation capacity, with an additional 521 MW nameplate capacity of projects projected to be on-line by June 1, 2017. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. The expense and volume of PURPA project power purchases during the last three years is included in the table below:

	Year Ended December 31,		
	2014	**2013**	**2012**
PURPA contract expense (in thousands)	$ 144,617	$ 131,338	$ 117,618
MWh purchased under PURPA contracts (in thousands)	2,286	2,127	1,961
Average cost per MWh from PURPA contracts	$ 63.26	$ 61.75	$ 59.98

Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions having jurisdiction over Idaho Power have each issued orders and rules regulating Idaho Power’s purchase of power from "qualifying facilities" that meet the requirements of PURPA. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility’s avoided costs. The IPUC and OPUC have established specific rules and regulations to calculate the avoided cost that Idaho Power is required to include in PURPA contracts. For PURPA power purchase agreements:

- Idaho Power is required to purchase all of the output from the facilities located inside its service territory, subject to some exceptions such as adverse impacts on system reliability.
- Idaho Power is required to purchase the output of projects located outside its service territory if it has the ability to receive power at the facility’s requested point of delivery on Idaho Power's system.

- The IPUC jurisdictional portion of the costs associated with PURPA contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and an Oregon PCA mechanism.
- IPUC and OPUC jurisdictional regulations have generally provided for PURPA standard contract terms of up to 20 years, though a current docket exists at the IPUC to review contract terms for future agreements.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 kilowatts (kW) and all other types of projects that are smaller than 10 average MWs. For PURPA qualifying facilities that exceed these size limitations, Idaho Power is required to negotiate an applicable price (premised on avoided costs) based upon IPUC regulations.
- The OPUC requires that Idaho Power pay the published avoided costs for all PURPA qualifying facilities with a nameplate rating of 10 MW or less and that Idaho Power negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations.

Idaho Power, as well as other affected electric utilities, have engaged in proceedings at the IPUC and OPUC relating to PURPA contracts. These proceedings have related to, among other things, appropriate contract term lengths and the prices paid for energy purchased from PURPA projects. Refer to Part II - Item 7 - MD&A - "Regulatory Matters - Renewable Energy Standards and Contracts" for a summary of those proceedings.

Emerging Energy Imbalance Markets: Utilities in the western United States outside the California Independent System Operator (California ISO) have traditionally relied upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply. These utilities have limited capability to transact within the hour outside their own borders. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The California ISO, PacifiCorp, and other parties implemented a new energy imbalance market in the fourth quarter of 2014 (California ISO-PAC EIM) under which the parties enabled their systems to interact for dispatch purposes. Similarly, the Northwest Power Pool (NWPP) Members Market Assessment and Coordination Committee has stated that it intends to implement the Security Constrained Economic Dispatch (NWPP SCED), an intra-hour energy balancing market, in 2016. The California ISO-PAC EIM and the NWPP SCED are similar but not identical approaches to balancing services and each are intended to reduce the costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Participation in both the California ISO-PAC EIM and the NWPP SCED are voluntary and available to all balancing authorities in the western United States. Idaho Power is an active participant in the development stage of the NWPP SCED project and is also evaluating the potential opportunities and challenges associated with the NWPP SCED and the California ISO-PAC EIM.

Transmission Services and Federal Tariff

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located anywhere from a few miles to hundreds of miles from customers. Idaho Power’s generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum capability and reliability. Idaho Power’s transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy. These interconnections, coupled with transmission line capacity made available under agreements with some of those entities, permit the interchange, purchase, and sale of power among entities in the Western Interconnection. Idaho Power provides wholesale transmission service for eligible transmission customers on a non-discriminatory basis. Idaho Power is a member of the WECC, the NWPP, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the Western Interconnection.

Transmission to serve Idaho Power's retail customers is subject to the jurisdiction of the IPUC and OPUC for retail rate making purposes. Idaho Power provides cost-based wholesale and retail access transmission services under the terms of a FERC approved OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers, including Idaho Power, have an equal opportunity to access the transmission system. As required by FERC standards of conduct, Idaho Power's transmission function is operated independently from Idaho Power's energy marketing function.

Idaho Power is jointly working on the permitting of two significant transmission projects. The Boardman-to-Hemingway line is a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho. The Gateway West line is a proposed 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. Both projects are intended to meet future anticipated resource needs and are discussed in Part II, Item 7 – MD&A - "Liquidity and Capital Resources - Capital Requirements" in this report.

Resource Planning

Integrated Resource Planning: The IPUC and OPUC require that Idaho Power prepare biennially an Integrated Resource Plan (IRP). Idaho Power filed its most recent IRP in June 2013. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

In February 2014, the IPUC accepted the 2013 IRP for filing and requested that Idaho Power continue monitoring environmental requirements at a national level and account for their impact in resource planning, continue to collaborate with stakeholders on how best to use energy efficiency as a resource, and continue to be actively involved in matters relating to the North Valmy coal-fired power plant and promptly apprise the IPUC of developments that could impact the company's continued reliance on that coal-fired resource. In July 2014, the OPUC acknowledged Idaho Power's short-term action items in the 2013 IRP. However, in its order the OPUC did not acknowledge Idaho Power's investments in selective catalytic reduction emissions technology being installed at the Jim Bridger plant. The OPUC stated that it would undertake a fair and thorough investigation of the prudence of the emissions technology investments at the Jim Bridger plant when Idaho Power seeks rate recovery for the investments.

During the time between IRP filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect economic conditions, anticipated resource development, changes in technology, and regulatory requirements.

Idaho Power expects to file the 2015 IRP in June 2015. Idaho Power has begun its 2015 IRP process, initiating the public involvement process and analyzing future anticipated loads. The load forecast Idaho Power expects to use for purposes of the 2015 IRP predicts an average annual growth rate of 1.2 percent for average loads and 1.5 percent for summer peak loads over the 20-year planning horizon from 2015 to 2034. The rate of load growth can impact the timing and extent of development of resources, such as new generation plants or transmission infrastructure, to serve those loads. The load forecast Idaho Power used in the 2013 IRP predicted an average annual growth rate of 1.1 percent for average loads and 1.4 percent for summer peak loads over the 20-year planning horizon from 2013 to 2032.

Recent studies outside of the IRP process that incorporate the potential for additional mandatory PURPA-related power purchases suggest that no peak-hour load deficit exists through 2021 under some circumstances. Thus, Idaho Power expects there may be available near term capacity to accommodate growth from economic development or increases in customers and loads. Idaho Power expects to be able to manage near-term summer peak capacity deficits until completion of the Boardman-to-Hemingway transmission line, which is expected to be in service in 2021 or beyond. If the Boardman-to-Hemingway line is not constructed by the time necessary to meet load demand, Idaho Power will need to identify alternatives to meet future load requirements. Should estimates of higher growth rates materialize, or were there to be a significant increase in loads due to new, unanticipated large-load customers, Idaho Power could be required to adjust its infrastructure development timing and plans accordingly.

Integration of Intermittent Resources: In response to the operational challenges associated with integrating intermittent wind and solar generation that Idaho Power must purchase pursuant to PURPA, and in recognition that the costs and challenges associated with integrating these resources will become even more pronounced as the volume of intermittent resources in Idaho Power's portfolio increases, Idaho Power continues efforts to better understand the effects of wind and solar generation on power system operation. As part of these efforts, Idaho Power has performed wind and solar integration studies aimed at providing insight into the maximum amounts of intermittent generation Idaho Power's system can accommodate without significantly impacting reliability. In further response to the integration challenges, Idaho Power has implemented an internally developed wind forecasting system, in recognition that cost-intensive modifications to operations intended to integrate wind are reduced, though not eliminated, with improved wind production forecasting. Due to the large volumes of solar generation projects being proposed under PURPA, the IPUC recently directed Idaho Power to update the solar integration study, taking into account the higher solar penetration levels. Idaho Power expects to complete and file the updated study during 2015. Also due to the large volumes of proposed solar projects, in January 2015 Idaho Power initiated a proceeding at the IPUC regarding the length of contract terms under PURPA contracts, described in Part II - Item 7 - MD&A - "Regulatory Matters."

Energy Efficiency and Demand Response Programs: Idaho Power has 19 energy efficiency and demand response programs targeting energy savings across the entire year and summer system demand reduction. These programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new infrastructure. Idaho Power's programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes, including efficient appliances and HVAC equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes;
- demand response programs to reduce peak summer demand through the voluntary interruption of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through a third-party demand response aggregator; and
- membership in the Northwest Energy Efficiency Alliance, which supports market transformation efforts across the region.

In 2014, Idaho Power's energy efficiency programs reduced energy usage by approximately 125,000 MWh. For 2014, Idaho Power had a demand response capacity of approximately 390 MW. In 2014 and 2013, Idaho Power expended approximately $37 million and $27 million, respectively, on energy efficiency and demand response programs. Funding for these programs is provided through a combination of the Idaho and Oregon energy efficiency tariff riders, base rates, and the Idaho PCA mechanism.

Environmental Regulation and Costs

Idaho Power's activities are subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment. Environmental regulation continues to impact Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, and the modification of system operations to accommodate environmental regulations. In addition to generally applicable regulations, the FERC licenses issued for Idaho Power's hydroelectric generating plants have numerous environmental requirements, such as the aeration of turbine water to meet dissolved gas and temperature standards in the waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power's three coal-fired power plants and three natural gas combustion turbine power plants are also subject to a broad range of environmental requirements, including air quality regulation. For a more detailed discussion of these and other environmental issues, refer to Item 7 – MD&A – "Environmental Matters" in this report.

Environmental Expenditures: Idaho Power's environmental compliance expenditures will remain significant for the foreseeable future, especially given the additional regulation proposed and under discussion at the federal level. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

	2015	**2016 - 2017**
Capital expenditures:		
Studies and measures at hydroelectric facilities	$ 13	$ 28
Investments in equipment and facilities at thermal plants	60	27
Total capital expenditures	$ 73	$ 55
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$ 19	$ 39
Operating costs for environmental facilities - thermal	12	26
Total operations and maintenance	$ 31	$ 65

Idaho Power anticipates that finalization of a number of federal and state rulemakings and other proceedings addressing, among other things, greenhouse gas and particulate emissions, hazardous materials, and endangered species could result in substantially increased operating and compliance costs in addition to the amounts set forth above, but Idaho Power is unable to estimate those costs given the uncertainty associated with potential future regulations.

Environmental Controls Cost Study: In connection with its IRP process, in February 2013 Idaho Power filed with the IPUC and OPUC the results of cost studies and scenario analyses conducted to assess the potential future investments necessary for the continued operation of the Jim Bridger and North Valmy coal-fired generation facilities. The Boardman plant was not included in the study because of the existing schedule to cease coal-fired operations at that plant by the end of 2020. The analysis compared the cost of future compliance with regulations to the cost of replacement generation capacity provided by combined-cycle combustion turbine technology and conversion of the units to natural gas. Because of the speculative nature of many of the future requirements, the analysis was performed under a range of fuel pricing assumptions, carbon cost assumptions, plant upgrade and retirement costs, environmental regulation assumptions, and replacement costs. Idaho Power concluded in its study that the Jim Bridger and North Valmy plants should be retained in its resource portfolio as coal-fired plants, and supports planned investments in environmental controls at those plants. However, Idaho Power will continue to monitor environmental requirements to assess whether environmental control upgrades at the coal-fired plants remain economically appropriate. Continued review of the economic appropriateness of further investment was included in a February 2014 order of the IPUC, in which the IPUC requested that Idaho Power continue monitoring environmental requirements at a national level and account for their impact in resource planning and promptly apprise the IPUC of developments that could impact the company's continued reliance on the North Valmy plant as a coal-fired resource. Idaho Power will continue to work with the plant's co-owner to monitor environmental requirements and costs associated with the plant, and to develop alignment on potential retirement dates for the plant.

Voluntary CO_2 Intensity Reduction Goal: Idaho Power continues to prepare for potential legislative and/or regulatory restrictions on emissions in order to help reduce the costs of complying with such restrictions on its customers. To that end, Idaho Power is engaged in voluntary greenhouse gas emissions intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce Idaho Power's resource portfolio's average carbon dioxide (CO_2) emissions intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emissions intensity of 1,194 lbs CO_2/MWh. Idaho Power's estimated CO_2 emissions intensity from its generation facilities, as submitted to the Carbon Disclosure Project, was as follows:

	2010	2011	2012	2013
Emission Intensity (lbs CO_2/MWh)	1,060	677	871	1,129

As of the date of this report, emission intensity information for 2014 was not yet available. The combination of effective utilization of hydroelectric projects, above average stream flows in some years, reduced usage of coal-fired facilities, and addition of the Langley Gulch natural gas-fired power plant positioned Idaho Power to extend its CO_2 emissions intensity reduction goal period for an additional two years, targeting an average reduction of 10 to 15 percent below its 2005 levels for the entire 2010 through 2015 time period.

IFS

IFS invests in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk with most of IFS's investments having been made through syndicated funds. IFS is no longer actively pursuing further investment opportunities, but will continue to maintain and manage its current portfolio of investments. At December 31, 2014, the gross amount of IFS's portfolio equaled $192 million in tax credit investments. IFS generated tax credits of $5.2 million, $5.5 million, and $5.5 million in 2014, 2013, and 2012, respectively.

IDA-WEST

Ida-West operates and has a 50 percent ownership interest in nine hydroelectric projects that have a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $9 million each year from 2012 to 2014.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below, along with their business experience during at least the past five years. Mr. J. LaMont Keen, a member of IDACORP's and Idaho Power's boards of directors and former President and Chief Executive Officer of IDACORP and Idaho Power, and Mr. Steven R. Keen, are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was appointed.

Senior Executive Officers (in alphabetical order)

DARREL T. ANDERSON, 56
- President and Chief Executive Officer of IDACORP, May 1, 2014 - present.
- President and Chief Executive Officer of Idaho Power Company, January 1, 2014 - present.
- President and Chief Financial Officer of Idaho Power Company, January 1, 2012 - December 31, 2013.
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 1, 2009 - April 30, 2014.
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company since September 2013.

REX BLACKBURN, 59
- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 1, 2009 - present.

LISA A. GROW, 49
- Senior Vice President - Power Supply of Idaho Power Company, October 1, 2009 - present.

STEVEN R. KEEN, 54
- Senior Vice President - Chief Financial Officer, and Treasurer of IDACORP, May 1, 2014 - present.
- Senior Vice President - Chief Financial Officer, and Treasurer of Idaho Power Company, January 1, 2014 - present.
- Vice President - Finance and Treasurer of IDACORP, Inc., June 1, 2010 - April 30, 2014.
- Senior Vice President - Finance and Treasurer of Idaho Power Company, January 1, 2012 - December 31, 2013.
- Vice President - Finance and Treasurer of Idaho Power Company, June 1, 2010 - December 31, 2011.
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 1, 2006 - May 31, 2010.

WARREN KLINE, 59
- Senior Vice President - Customer Operations of Idaho Power Company, June 1, 2014 - present.
- Vice President - Customer Operations of Idaho Power Company, May 20, 2010 - May 31, 2014.
- Vice President - Customer Service and Regional Operations of Idaho Power Company, July 20, 2005 - May 19, 2010.

DANIEL B. MINOR, 57
- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President of IDACORP, Inc., May 20, 2010 - present.
- Executive Vice President - Operations of Idaho Power Company, October 1, 2009 - December 31, 2011.

Other Executive Officers (in alphabetical order)

PATRICK A. HARRINGTON, 54
- Corporate Secretary of IDACORP, Inc. and Idaho Power Company, March 15, 2007 - present.

LONNIE KRAWL, 51
- Vice President and Chief Information Officer of Idaho Power Company, October 1, 2013 - present.
- Director of Human Resources of Idaho Power Company, July 25, 2009 - September 30, 2013.

LUCI K. MCDONALD, 57
- Vice President - Human Resources and Corporate Services of Idaho Power Company, May 20, 2010 - present.
- Vice President - Human Resources and Corporate Services of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President - Human Resources of IDACORP, Inc. and Idaho Power Company, December 6, 2004 - May 19, 2010.

KEN W. PETERSEN, 51

- Vice President, Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2014 - present.
- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - December 31, 2013.
- Corporate Controller of IDACORP, Inc. and Idaho Power Company, December 29, 2007 - May 19, 2010.

N. VERN PORTER, 55

- Vice President - Idaho Power Company, January 1, 2014 - present.
- Vice President - Delivery Engineering and Construction of Idaho Power Company, May 17, 2012 - December 31, 2013.
- Vice President - Delivery Engineering and Operations of Idaho Power Company, October 1, 2009 - May 16, 2012.

GREGORY W. SAID, 60

- Vice President - Regulatory Affairs of Idaho Power Company, January 20, 2011 - present.
- General Manager of Regulatory Affairs of Idaho Power Company, April 3, 2010 - January 19, 2011.
- Director, State Regulation of Idaho Power Company, August 23, 2008 - April 2, 2010.

LORI D. SMITH, 54

- Vice President and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Vice President - Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2008 - May 19, 2010.

ITEM 1A. RISK FACTORS

IDACORP and Idaho Power operate in an industry and business environment that involves significant risks, many of which are beyond the companies' control. The circumstances and factors set forth below may have a material impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements. These risk factors, as well as other information in this report and in other reports the companies file with the SEC, should be considered carefully when evaluating IDACORP and Idaho Power.

If the Idaho Public Utilities Commission, the Public Utility Commission of Oregon, or the Federal Energy Regulatory Commission grant less recovery through rates than Idaho Power needs to cover costs and earn a reasonable rate of return, IDACORP's and Idaho Power's financial condition and results of operations may be adversely affected. The prices that the Idaho Public Utilities Commission and Public Utility Commission of Oregon authorize Idaho Power to charge for its retail services, and the tariff rate that the Federal Energy Regulatory Commission permits Idaho Power to charge for its transmission services, are generally the most significant factors influencing IDACORP’s and Idaho Power’s business, results of operations, and financial condition. The rates ultimately approved by regulators may not match prior or anticipated future expenses, and recovery of expenses may lag behind the occurrence of those expenses. The ratemaking process typically involves multiple intervening parties, including governmental bodies, consumer advocacy groups, and customers, generally with the common objective of limiting rate increases or even reducing rates.

Further, while rate regulation is premised on the assumption that rates will be established that are fair, just, and reasonable, regulators have considerable discretion in applying this standard. The Idaho Public Utilities Commission and the Public Utility Commission of Oregon have the authority to disallow recovery of any costs that they consider unreasonable or imprudently incurred. Collection of costs and capital expenditures through rates often occurs subsequent to the time those costs and expenditures are incurred, resulting in a lag in collection. Idaho Power's regulators may also disagree with Idaho Power's rate calculations under various tracking and decoupling mechanisms, like the power cost adjustment and fixed cost adjustment mechanisms. Regulators may also decide to modify or eliminate these mechanisms, which may make it more difficult for Idaho Power to recover its costs in the rates it charges to customers. Thus, the regulatory process does not assure that Idaho Power will be able to fully recover its costs or achieve the rate of return authorized or contemplated in connection with the ratemaking process. In a number of proceedings in recent years, Idaho Power has been denied recovery, or required to defer recovery pending the next general rate case, including denials or deferrals related to compensation expenses and construction expenditures. In some instances, denial of recovery may cause IDACORP and Idaho Power to record an impairment of those assets. If Idaho Power's costs are not fully and timely recovered through the rates ultimately approved by regulators, IDACORP's and Idaho Power's financial condition and results of operations, and its ability to earn a return on investment and meet financial obligations, could be adversely affected.

For additional information relating to Idaho Power's regulatory framework and recent regulatory matters, see Part I - Item 1 - "Business - Utility Operations," Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, and Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Matters" in this report.

Idaho Power's cost recovery deferral mechanisms and methods may not function as intended, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power has power cost adjustment mechanisms in its Idaho and Oregon jurisdictions and a fixed cost adjustment mechanism in Idaho that provide for periodic adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms track Idaho Power’s actual net power supply costs (primarily fuel and purchased power less off-system sales) and compare these amounts to net power supply costs being recovered in retail rates. A majority, but not all, of the variance between these two amounts is deferred for future recovery from, or refund to, customers through rates. Consequently, the power cost adjustment mechanisms only partially offset the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydroelectric generation, and volatile wholesale energy prices. When costs rise above the level recovered in current retail rates, it adversely affects Idaho Power’s operating cash flow and liquidity until those costs are recovered from customers. Further, during 2014 the Idaho Public Utilities Commission opened dockets to review the operation of the Idaho power cost adjustment mechanism and the fixed cost adjustment mechanism. Any future modification or elimination of the mechanisms based on these or subsequent proceedings may increase Idaho Power's financial exposure to changes in power costs and collection of fixed costs.

IDACORP's and Idaho Power's business, financial condition, and results of operations may be negatively affected by changes in customer growth or customer usage. Customer growth and customer usage are affected by a number of factors outside of the control of IDACORP and Idaho Power, such as implementation of energy efficiency measures, customer-generated power such as from rooftop solar panels, demand side management requirements, and economic and demographic conditions, such as population changes, job and income growth, housing starts, new business formation or migration, and the overall level of economic activity. The regional economy in which Idaho Power operates is influenced by conditions in the agriculture, recreation, technology, medical, and other industries, and as these conditions change, IDACORP's and Idaho Power's revenues will be impacted. Weak economic conditions may reduce the amount of energy Idaho Power’s customers consume, result in a loss of customers (including large-load industrial and commercial customers) or further decrease the customer growth rate, and increase the likelihood and prevalence of late payments and uncollectible accounts. The adoption of technology by customers can also have both positive and negative impacts on sales. Some new technologies and modern equipment utilize less energy than in the past, while new electric technologies like electric vehicles can create additional demand.

In light of the need to predict future electric power demands and how Idaho Power can meet those demands, Idaho Power prepares and periodically updates a load forecast as part of its integrated resource planning process. In doing so, Idaho Power makes load estimates that are based on a number of factors that are uncertain and difficult to estimate, including those described above. Any unanticipated increase in the demand for energy could result in increased reliance on higher-cost purchased power to meet peak system demand, the need to initiate new demand response and energy efficiency programs, or the need to accelerate investment in additional generation or transmission resources. If the incremental costs associated with the unanticipated changes in loads exceed the incremental revenue received from those sales, and Idaho Power is unable to secure timely and full rate relief to recover those costs, the resulting imbalance could have an adverse effect on IDACORP's and Idaho Power's financial condition and results of operations. Decreases in loads also have the potential to adversely affect IDACORP and Idaho Power. A resulting decrease in overall customer usage or collections and slower or negative load growth may delay or decrease capital spending, which can adversely affect Idaho Power's rate base used for establishing customer rates and may reduce revenues, earnings, and cash flows.

Depending on changes in load and infrastructure project timing, Idaho Power may seek to accelerate, scale back, modify, or eliminate projects, or seek alternative projects, to accommodate anticipated resource needs and to help ensure its ability to provide reliable electric service and meet load and transmission capacity obligations. Scaling back or eliminating a project due to regulatory challenges or other factors influencing the feasibility of a project may result in Idaho Power pursuing one or more separate, more costly projects. For instance, if Idaho Power were unable to secure permits or joint funding commitments to develop its 500-kV transmission projects, it may terminate those projects and seek other resources to serve loads. Termination of a project carries with it the potential for a write-off of all or a portion of the costs associated with the project if regulators deem the costs incurred imprudent.

Extreme weather events and their associated impacts can adversely affect IDACORP's and Idaho Power's results of operations and financial condition. Extreme weather events and their associated impacts (such as fires and high winds) can damage generation facilities and disrupt transmission and distribution systems, causing service interruptions and extended outages, increasing supply chain costs, and limiting Idaho Power's ability to meet customer energy demand. The effect of the failure of Idaho Power's facilities to operate as planned under extreme weather conditions is particularly burdensome during peak demand periods, such as hot summer days. Disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses and could negatively affect IDACORP's and Idaho Power's results of operations and financial condition. Economic losses incurred as a result of such events might not be recoverable through customer rates or covered in full by insurance.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could decrease revenues. Idaho Power primarily generates power at large central facilities, which results in economies of scale and lower costs than many newer generation technologies. However, the increasing costs of energy have incentivized the development of new technologies for power generation, power storage, and energy efficiency, and further investment in research and development to make those technologies more efficient and cost-effective. For instance, while solar technology remains a relatively high-cost means of power generation, in recent years there have been numerous advancements in the design of solar generation facilities and the materials used in panels that may further increase the efficiency and power output of solar generation sources in a more cost-effective manner. As the cost of the technology has decreased, there has been an increase in adoption of rooftop solar systems by both residential and commercial customers, particularly in areas where electric rates are high and the weather is suitable for solar power systems. There is potential that these alternative power generation systems, particularly if coupled with power storage devices, could become sufficiently cost-effective and efficient that an increasing number of Idaho Power's customers choose to install such systems on their homes or businesses. Additionally, considerable emphasis has been placed on energy efficiency, such as LED lighting. Energy efficiency programs, including programs sponsored by Idaho Power under a directive from state regulatory commissions, are designed to reduce energy demand. If Idaho Power is unable to maintain adequate regulatory mechanisms or develop new mechanisms or rate structures allowing for timely and adequate cost recovery, declining usage would result in under-recovery of fixed costs. Further, widespread adoption of distributed generation and declining usage may decrease the need for electric power supplied by Idaho Power, which would reduce Idaho Power's revenue, potentially result in the impairment of assets that produce and deliver energy, and have a negative impact on IDACORP's and Idaho Power's results of operations and financial condition.

Capital expenditures for infrastructure, risks associated with construction of that infrastructure, and the timing and availability of cost recovery for the expenditures, can significantly affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power's business is capital intensive and requires significant investments in energy generation, transmission, and distribution infrastructure. A significant portion of Idaho Power's facilities were constructed many years ago, and thus require periodic upgrades and frequent maintenance. Also, long-term anticipated increases in both the number of customers and the demand for energy require expansion and reinforcement of that infrastructure. For instance, Idaho Power is in the permitting process for two 500-kV transmission line projects, which are intended to help meet future customer energy demands. Construction projects are subject to usual permitting and construction risks that can adversely affect project costs and the completion time. These risks include, as examples:

- the ability to timely obtain labor or materials at reasonable costs, and defaults by contractors;
- equipment, engineering, and design failures;
- the effects of adverse weather conditions;
- availability of financing;
- the ability to obtain and comply with permits and land use rights, and environmental constraints;
- delays and costs associated with disputes and litigation with third parties; and
- changes in applicable laws or regulations.

If Idaho Power is unable to complete the construction of a project, or incurs costs that regulators do not deem prudent, it may be unable to recover its costs in full through rates or on a timely basis. In many instances, review by regulators of the prudence of investments will not occur until expenditures have been made. Even if Idaho Power completes a construction project, the total costs may be higher than estimated and/or higher than amounts approved for recovery by regulators. Further, if Idaho Power is unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, seek to develop additional generation facilities within areas where Idaho Power has available transmission capacity or pursue other more costly options to serve loads. To limit the timing-related risks of these projects, Idaho Power may enter into purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals or siting or environmental permits. If any of the projects are canceled for any reason, including Idaho Power's failure to receive necessary regulatory approvals or permits or because the project is no longer economical, Idaho Power could incur significant cancellation penalties under the purchase order or construction contracts. Additionally, termination of a project carries with it the potential for impairment of the associated asset if regulators deny full recovery of project costs. Thus, termination of a project could negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP's and Idaho Power's businesses are subject to an extensive set of environmental laws, rules, and regulations, which could impact their operations and increase costs of operations, potentially rendering some generating units uneconomical to maintain or operate, and could increase the costs and alter the timing of major projects. A number of federal, state, and local environmental statutes, rules, and regulations relating to air and water quality, natural resources, and health and safety are applicable to IDACORP's and Idaho Power's operations. Many of these laws, including the Environmental Protection Agency's proposed rules under Section 111(d) under the Clean Air Act, are described in Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Matters" in this report. These laws and regulations generally require IDACORP and Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, and other approvals, including through substantial investment in pollution controls, and may be enforced by both public officials and private individuals. Some of these regulations are pending, changing, or subject to interpretation, and failure to comply may result in penalties, mandatory operational changes, and other adverse consequences, including costs associated with defending against claims by governmental authorities or private parties and complying with new operating requirements.

Environmental regulations have created the need for Idaho Power to install new pollution control equipment at, and may cause Idaho Power to perform environmental remediation on, its owned and co-owned power generation facilities, often at a substantial cost. For instance, Idaho Power is in the process of installing environmental control apparatus in two units of its co-owned Jim Bridger power plant at an estimated cost of $113 million, and may install a second set of control apparatus at two other units at that plant in or around 2021 and 2022. IDACORP and Idaho Power will incur other costs associated with existing environmental regulations, and the companies expect to incur additional costs associated with pending and future environmental regulations, and those costs are likely to be substantial. If the costs of compliance with those new regulations renders the generating facilities uneconomical to maintain or operate, Idaho Power would need to identify alternative resources for power, potentially in the form of new generation and transmission facilities, market power purchases, demand-side management programs, or a combination of these and other methods.

Idaho Power is not guaranteed timely or full recovery of those costs, and regulators may not grant prior approval of cost recovery. For example, in 2013 the Idaho Public Utilities Commission declined to approve Idaho Power's application requesting a binding commitment to provide rate base treatment for Idaho Power's estimated share of the capital investment in environmental control upgrades at the Jim Bridger power plant, instead reserving the prudence determination (and thus ratemaking treatment) for subsequent proceedings. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its existing infrastructure or construction of new infrastructure. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's generation or transmission facilities could be delayed, halted, or subjected to additional costs. At the same time, consumer preference for renewable or low greenhouse gas-emitting sources of energy could impact the desirability of generation from existing sources and require significant investment in new generation and transmission resources. If Idaho Power is unable to recover in full these increased costs through the ratemaking process, such under-recovery would negatively impact IDACORP's and Idaho Power's financial condition and results of operations.

Relicensing of the Hells Canyon hydroelectric project and construction of the proposed Gateway West and Boardman-to-Hemingway 500-kV transmission lines requires consultation under the Endangered Species Act to determine the effects of these projects on any listed species within the project areas. The presence of sage grouse, which is being considered for listing as an endangered species, in the vicinity of the Gateway West and Boardman-to-Hemingway transmission projects has required more extensive, costly, and time consuming evaluation and engineering. These and other requirements of the Endangered Species Act, Clean Air Act, Clean Water Act, and similar environmental laws may increase costs, adversely affect the timing or ability to complete major projects, and may have an adverse effect on IDACORP's and Idaho Power's results of operations and financial condition.

Factors contributing to lower hydroelectric generation can increase costs and negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. During 2014, 47 percent of Idaho Power's electric power generation was from hydroelectric facilities. Because of Idaho Power's heavy reliance on hydroelectric generation, snow pack, the timing of run-off, drought conditions, and the availability of water in the Snake River basin can significantly affect its operations. The combination of a long-term trend of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed approach to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights may further reduce Snake River flows available for hydroelectric generation. When hydroelectric generation is reduced, Idaho Power must increase its use of more expensive thermal generating resources and purchased power; therefore, costs increase and opportunities for off-system sales are reduced, reducing earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most of the increase in net power supply costs caused by lower hydroelectric generation. Recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, negatively affecting cash flows and liquidity.

Conditions imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and negatively affect IDACORP's or Idaho Power's results of operations and financial condition. For the last several years, Idaho Power has been engaged in an effort to renew its federal license for its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The existence of endangered and threatened species in the watershed may result in major operational changes to the region’s hydroelectric projects, which may be reflected in hydroelectric licenses. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power’s energy requirements. One particularly significant issue identified in connection with the Hells Canyon Complex relicensing effort involves water temperature gradients in the Snake River below the Hells Canyon dam. Certain parties in the relicensing proceedings have advocated for the installation of water temperature management apparatus which, if required to be installed, would require substantial capital expenditures to construct and maintain. Idaho Power may be unable to recover in full the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, or whether a new multi-year license will ultimately be issued. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs (including power purchase costs), and reduce hydroelectric generation, which could negatively affect results of operations and financial condition.

IDACORP's and Idaho Power's operating results are subject to seasonal fluctuations, and unusually mild or extreme temperatures and weather can impact their results of operations and financial condition. Idaho Power's electric power sales are seasonal, with demand in Idaho Power's service area peaking during the hot summer months, with a secondary peak during the cold winter months. Electric power demands by irrigation customers in Idaho Power's service area, which are impacted by temperatures and the timing and amount of precipitation, among other factors, can also create significant seasonal changes in usage. Seasonality of revenues may be enhanced by Idaho Power's tiered rate structure, under which rates charged to customers are often higher during higher-load periods. Market prices for power also often increase significantly during these peak periods, at times when Idaho Power is required to purchase power in the wholesale markets to meet customer demand. By contrast, when temperatures are relatively mild or where precipitation supplants irrigation systems, loads are often lower as customers are not using electricity for heating and air conditioning or irrigation purposes. Thus, unusually mild weather or the timing and extent of precipitation can cause IDACORP's and Idaho Power's results of operations and financial condition to fluctuate seasonally and from year to year.

Complying with renewable portfolio standards could increase capital expenditures and operating costs and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. Renewable portfolio standards require that electricity providers obtain a minimum percentage of their power from renewable energy sources by a specified date. Idaho Power’s operations in Oregon will be required to comply with a 10 percent renewable portfolio standard beginning in 2025, and it is possible that other states, including Idaho, could adopt renewable portfolio standards. The cost of purchasing or generating power from renewable energy sources is often greater than fossil fuel and hydroelectric generation sources, and construction of renewable energy facilities involves significant capital expenditures. As a result, new state or federal renewable portfolio standards could increase capital expenditures and operating costs and negatively affect results of operations and financial condition. In accordance with a renewable energy certificate management plan on file with the Idaho Public Utilities Commission, Idaho Power currently sells the renewable energy certificates it receives in connection with its power purchases from some renewable energy generation resources, using the proceeds to benefit customers. Enactment of a renewable portfolio standard in Idaho would cause Idaho Power to retain and retire some or all of those renewable energy certificates rather than sell them for the benefit of customers, and could thus result in increased rates.

Idaho Power’s use of coal and natural gas to fuel power generation facilities exposes it to commodity availability and price risk, which can adversely affect IDACORP's and Idaho Power's results of operations and financial condition. As part of its normal business operations, Idaho Power purchases coal and natural gas in the open market or under short-term or long-term contracts, often with variable-pricing terms. Market prices for coal and natural gas are influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Following the completion of the Langley Gulch natural gas-fired power plant, Idaho Power has become more dependent on natural gas for a portion of its electric generating capacity. Natural gas transportation to Idaho Power's natural gas plants is limited to one primary pipeline, presenting a heightened possibility of supply constraint and disruptions separate from the risk of counterparty default. Most of Idaho Power's coal supply arrangements are under long-term contracts for coal originating in Wyoming, and thus Idaho Power is exposed to risk of disruption of coal production in, or transportation from, that region. Idaho Power may from time to time enter into new, or renegotiate, these long-term contracts, but can provide no assurance that such contracts will be negotiated or renegotiated, as the case may be, on satisfactory terms, or at all. There also can be no assurance that counterparties to the coal supply agreements will fulfill their obligations to supply coal, and they may experience financial or technical problems that inhibit their ability to deliver coal. The coal supply agreements also contain terms that allow the coal suppliers to curtail the delivery of coal in certain circumstances, such as in the event of a natural disaster. Defaults by coal and natural gas suppliers may cause Idaho Power to seek alternative, and potentially more costly, sources of fuel or rely on other generation sources or wholesale market power purchases. Idaho Power may not be able to fully recover these increased costs through rates or its power cost adjustment mechanisms, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Historically, natural gas prices have tended to be more volatile than prices for other fuel sources. Recently, however, the availability of natural gas from shale production has lessened both natural gas prices and price volatility. Market power prices are impacted in part by the availability and cost of natural gas -- as the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to generate and sell into the wholesale markets electricity at increasingly competitive prices, which could decrease Idaho Power's off-system sales revenues.

Idaho Power's generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, accidents and workforce safety matters, release of hazardous or toxic substances into the air, water, or ground, acts of terrorism or sabotage, the loss of cost-effective disposal options for solid waste such as coal ash, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of those facilities could result in reduced customer satisfaction, reputational harm, and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses for alternative fuels or wholesale market power purchases. Accidents, electrical contacts, fires, explosions, catastrophic failures, general system damage or dysfunction, and other unplanned events related to Idaho Power's infrastructure would increase repair costs and may expose Idaho Power to claims for personal injury or property damage. Further, the transmission system in Idaho Power's service territory is constrained, limiting the ability to transmit electric energy within the service territory and access electric energy from outside the service territory during high-load periods. Idaho Power's transmission facilities are also interconnected with those of third parties, and thus operation of Idaho Power's and third parties' facilities could be adversely affected by unexpected or uncontrollable events. These transmission constraints and events could result in failure to provide reliable service to customers and the inability to deliver energy from generating facilities to the power grid, or not being able to access lower cost sources of electric energy, which could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

As discussed in Item 1 - "Business" in this report, in the fourth quarter of 2014 new energy imbalance markets began to emerge in the western United States. The energy imbalance markets are intended to allow for automated near real-time dispatch of generation resources. Idaho Power has not yet joined the energy imbalance markets and cannot predict the ultimate impact, whether positive or negative, that the energy imbalance markets will have on its ability to make economic off-system sales and purchase power in the market. There is potential that, whether Idaho Power joins an energy imbalance market or not, Idaho Power's off-system sales will decrease or purchased power costs will increase, which could adversely affect IDACORP's and Idaho Power's results of operations and financial condition.

Volatility in the financial markets, or denial of regulatory authority to issue debt or equity securities, may negatively affect IDACORP's and Idaho Power's ability to access capital and/or increase their cost of borrowing, or result in losses on investments. IDACORP and Idaho Power use short-term and long-term debt as a significant source of liquidity and funding for capital requirements not satisfied by operating cash flow. In a volatile credit environment IDACORP and Idaho Power may be unable to issue short-term or long-term debt at reasonable interest rates or at all, one or more of the participating banks in IDACORP's and Idaho Power's credit facilities may default on their obligations to make loans under, or may withdraw from, the credit facilities, or IDACORP's and Idaho Power's access to capital may otherwise be inhibited. In addition, at times Idaho Power has a relatively large balance of short-term investments. Volatility in the financial markets may result in a lack of liquidity for short-term investments and declines in value of some investments. The occurrence of any of these events could affect Idaho Power's ability to execute its business plan and adversely affect IDACORP's and Idaho Power's results of operations and financial condition.

Idaho Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations and capital expenditures. Notably, without additional approval from those commissions, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. IDACORP's and Idaho Power's credit facilities include financial covenants that limit the amount of debt that can be outstanding as a percentage of total capital. Idaho Power's long-term debt has also been issued under an indenture that contains a number of financial covenants. Failure to maintain these covenants could preclude IDACORP and Idaho Power from issuing commercial paper, borrowing under their credit facilities, or issuing long-term debt, and could trigger a default and repayment obligation under debt instruments, which could adversely impact IDACORP's and Idaho Power's financial condition and liquidity.

A downgrade in IDACORP's and Idaho Power's credit ratings could affect the companies' ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Access to capital markets is important to IDACORP's and Idaho Power's ability to operate and to complete capital projects. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power. These ratings are premised on financial ratios and performance, the regulatory environment and mechanisms, management and their effectiveness, resource risks and power supply costs, and other factors. These ratings impact access to, and the cost of, borrowing. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source of short-term financing. Downgrades of IDACORP's or Idaho Power's credit ratings, or those affecting relationship banks, could limit the companies' ability to access short- and long-term capital under reasonable terms or at all, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Idaho Power's risk management policy and programs relating to economically hedging commodity exposures and credit risk may not always perform as intended, and as a result IDACORP and Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities, and enters into financial hedges to mitigate in part exposure to variable commodity prices. IDACORP and Idaho Power could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. The derivative instruments might not offset the underlying exposure being mitigated as intended, due to pricing inefficiencies or other terms of the derivative instruments, and any such failure to mitigate exposure could result in financial losses. Further, forecasts of future fuel needs and loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. To the extent that commodity markets are illiquid, Idaho Power may not be able to execute its risk management strategies, which could result in undesired over-exposure to unhedged positions. As a result, risk management actions, or the failure or inability to manage commodity price and counterparty risk, may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power could be subject to penalties and operational changes if it violates mandatory reliability and security requirements, which could adversely impact IDACORP's and Idaho Power's results of operations and financial condition. As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Idaho Power has received in recent years notices of violations from, and regularly self-reports reliability standard compliance issues to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council, as applicable. Potential monetary and non-monetary penalties for a violation of Federal Energy Regulatory Commission regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power for its actual or alleged failure to comply with reliability and security requirements could have a negative effect on its and IDACORP's results of operations and financial condition.

Federally mandated purchases of power from renewable energy projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect Idaho Power's and IDACORP's results of operations and financial condition. An abundance of intermittent, non-dispatchable generation from renewable energy projects interconnected with Idaho Power's system during times when Idaho Power has available lower-cost resources to meet load demands has an impact on the operation of Idaho Power's hydroelectric generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Idaho Power's purchases of power from certain renewable energy projects, which Idaho Power is generally obligated to purchase under federal law regardless of the then-current load demand, availability of lower cost generation resources, or wholesale energy market prices, increase the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, increasing power purchase costs and customer rates. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its operational costs will continue to increase as a result of its efforts to integrate intermittent, non-dispatchable generation from a large number of renewable energy projects. Idaho Power anticipates that costs will escalate as the volume of intermittent wind and solar generation on its system increases, which may negatively affect IDACORP's and Idaho Power's results of operations and financial condition.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs and funding obligations could adversely affect IDACORP's and Idaho Power's financial condition and results of operations - primarily cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power's plan costs and funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are inherently uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including timing of retirements or changes in life expectancy assumptions, may also increase Idaho Power's plan costs and funding requirements. Future pension funding requirements and the timing of funding payments are also subject to the impacts of changes in legislation. Depending on the timing of contributions to the plans and Idaho Power's ability to recover costs through rates, cash contributions to the plans could reduce the cash available for the companies' businesses and payment of dividends. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

As a holding company, IDACORP does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments. IDACORP is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. IDACORP's subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other payments. The ability of IDACORP's subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which may reduce or cease payment of dividends at any time. See Note 6 - "Common Stock" to the consolidated financial statements included in this report for a further description of restrictions on IDACORP's and Idaho Power's payment of dividends.

Employee workforce factors, including the impacts of an aging workforce with specialized utility-specific functions, could increase costs and adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, an aging workforce, and impacts of efforts to organize the workforce. Idaho Power's operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, and generation plant operators, require extensive, specialized training. Idaho Power expects that a significant portion of its skilled workforce will be retiring within the current decade, which will require Idaho Power to attract, train, and retain new employees to help prevent a loss of institutional knowledge and avoid a skills gap. Without a skilled workforce, Idaho Power's ability to provide reliable service to its customers and meet regulatory requirements will be challenging, which could negatively affect earnings. The costs associated with attracting and retaining appropriately qualified employees to replace an aging and skilled workforce could also have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims. From time to time in the normal course of business IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other adverse consequences. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. As an example, over the past decade Idaho Power has been a party to proceedings relating to high prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001, which caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the Federal Energy Regulatory Commission to initiate its own investigations. While Idaho Power has largely disposed of direct claims in those proceedings, the settlements and associated Federal Energy Regulatory Commission orders did not eliminate the potential for speculative "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. Idaho Power's settlement payments in those proceedings have been relatively small to date, but the legal costs of defending the claims over the past decade have been substantial. In recent years, Idaho Power has also been a party to legal proceedings advanced by private parties relating to alleged violations of environmental statutes and regulations at its co-owned coal-fired plants. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have a negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their business practices and procedures, including the nature and extent of operation of generation facilities, which could also have a negative effect on their financial positions and results of operations.

Acts or threats of terrorism, cyber attacks, security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations or the electric power grid could negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power operates in an industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. Idaho Power's generation and transmission facilities and its grid operations are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed "critical infrastructure," in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, national public health or safety, or any combination of those matters. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to protect, repair, and insure Idaho Power's assets, and could further adversely affect Idaho Power's operations by contributing to disruption of supplies and markets for natural gas or coal used to fuel gas- or coal-fired power plants.

In the normal course of business, Idaho Power collects, processes, and retains sensitive and confidential customer and employee information and the proprietary information of both Idaho Power and third parties. Cyber attacks have evolved to become increasingly sophisticated and difficult to detect in recent years. Despite the cyber security measures in place, Idaho Power's networks and infrastructure could be vulnerable to security breaches, data leakage, or other similar events that could interrupt operations, expose Idaho Power to liability, and require that Idaho Power remedy the security breaches. Those breaches and events may result from acts of Idaho Power employees, contractors, or third parties. Separate from liability to third parties and information owners, if Idaho Power's information technology and security systems were to fail or be breached and Idaho Power were unable to recover the systems and/or data in a timely manner, Idaho Power may be unable to fulfill critical business functions.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP's or Idaho Power's financial condition and results of operations. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. The companies' tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation, employment-related taxes, and Canadian goods and services and provincial taxes, and ongoing issues related to these taxes. In recent years, tax settlements, as well as state regulatory mechanisms with tax-related provisions (such as Idaho Power's 2011 regulatory settlement stipulation with the Idaho Public Utilities Commission, which has been extended, with modifications, for future periods), have significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of ongoing and future income tax proceedings, or the state public utility commissions' treatment of those tax outcomes, could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could negatively affect IDACORP's and Idaho Power's earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho

Power anticipate or request from applicable state regulatory commissions, which could have a negative effect on their financial condition and results of operations.

Changes in accounting standards or rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board and the Securities and Exchange Commission may make changes to accounting standards that impact presentation and disclosures of financial condition and results of operations. Further, new accounting orders issued by the Federal Energy Regulatory Commission could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles to reflect the impact of regulatory decisions in its financial statements and to defer certain costs as regulatory assets until those costs are collected in rates, and to defer some items as regulatory liabilities. If recovery of these amounts ceases to be probable, if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate some or all of those regulatory assets or liabilities. Any of these circumstances could result in write-offs and have a material effect on IDACORP's and Idaho Power’s financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power's properties consist of the physical assets necessary to support its utility operations, which include generation, transmission, and distribution facilities, as well as coal assets that support one of its coal-fired generation plants. In addition to these physical assets, Idaho Power has rights-of-way and water rights that enable it to use its facilities. Idaho Power’s system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, three natural gas-fired plants in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. As of December 31, 2014, the system also includes approximately 4,858 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 222 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,072 pole-miles of distribution lines.

Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power's hydroelectric projects is discussed in Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects." Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are listed below:

Project	Nameplate Capacity (kW)[1]	License Expiration
Hydroelectric Projects:		
Properties Subject to Federal Licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	12,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,166,900	2005 [2]
Swan Falls	27,170	2042
American Falls	92,340	2025
Cascade	12,420	2031
Milner	59,448	2038
Twin Falls	52,897	2040
Other Hydroelectric:		
Clear Lakes - Thousand Springs	11,300	
Total Hydroelectric	1,709,045	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired)[3]	770,501	
North Valmy (coal-fired)[3]	283,500	
Boardman (coal-fired)[3][4]	64,200	
Danskin (gas-fired)	270,900	
Langley Gulch (gas-fired)	318,452	
Bennett Mountain (gas-fired)	172,800	
Salmon (diesel-internal combustion)	5,000	
Total Steam and Other	1,885,353	
Total Generation	3,594,398	

(1) Actual generation capacity from a facility may be greater or less than the rated nameplate generation capacity.

(2) Licensed on an annual basis while the application for a new multi-year license is pending.

(3) Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.

(4) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations by December 31, 2020.

IDACORP's and Idaho Power's headquarters are located in Boise, Idaho. The corporate headquarters campus is comprised of approximately 306,000 square feet of owned office space and approximately 51,000 square feet of leased office space. Excluding Idaho Power's power generation facilities and substations, Idaho Power owns an additional 605,000 square feet of office, warehouse, and industrial space to support its operations in Idaho and Oregon.

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Substantially all of Idaho Power's property is subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. Idaho Power's property is subject to minor defects common to properties of such size and character that it believes do not materially impair the value to, or the use by, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

Idaho Energy Resources Co. owns a one-third interest in BCC and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant. Ida-West holds 50-percent interests in nine hydroelectric plants that have a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – “Contingencies” to the consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP’s common stock, without par value, is traded on the New York Stock Exchange (NYSE). On February 13, 2015, there were 10,872 holders of record of IDACORP common stock and the closing stock price was $61.55 per share. The outstanding shares of Idaho Power’s common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

IDACORP and Idaho Power paid dividends of $89 million, $79 million, and $69 million in 2014, 2013, and 2012, respectively. The amount and timing of dividends paid on IDACORP’s common stock are within the discretion of IDACORP’s board of directors, subject to other restrictions. The board of directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP’s current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. Notwithstanding the dividend policy adopted by IDACORP's board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

IDACORP's and Idaho Power's payment of dividends is subject to a number of restrictions. For information relating to those restrictions, see Note 6 - “Common Stock” to the consolidated financial statements included in this report.

The following table shows the reported high and low sales price of IDACORP’s common stock and dividends paid for 2014 and 2013 as reported by the NYSE:

	2014			2013		
Quarter	High	Low	Dividends paid per share	High	Low	Dividends paid per share
1st	$ 56.65	$ 50.21	$ 0.43	$ 48.53	$ 43.13	$ 0.38
2nd	57.86	52.91	0.43	50.16	46.03	0.38
3rd	58.79	51.70	0.43	54.74	45.62	0.38
4th	70.05	53.39	0.47	53.99	47.57	0.43

During 2014, 2013, and 2012, Idaho Power paid dividends to its parent, IDACORP, in the amounts shown in Idaho Power's Consolidated Statements of Retained Earnings included in this report.

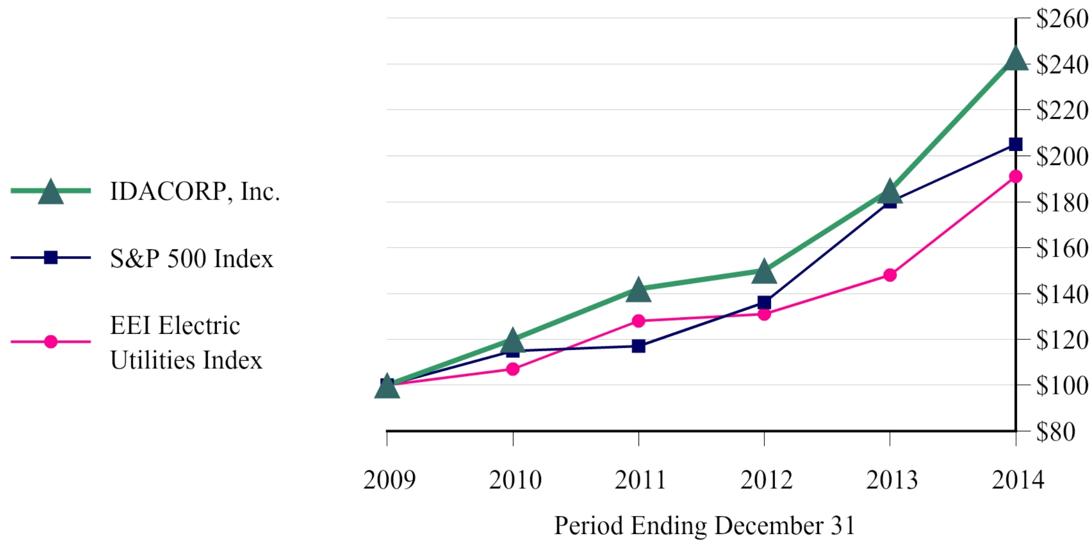
IDACORP did not repurchase any shares of its common stock during the fourth quarter of 2014.

Performance Graph

The graph below shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index, and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on

December 31, 2009, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.

Comparison of Cumulative Total Return
$100 Invested December 31, 2009



Source: Bloomberg and EEI

	2009	2010	2011	2012	2013	2014
IDACORP	$ 100.00	$ 119.85	$ 141.72	$ 149.76	$ 184.97	$ 243.49
S&P 500	100.00	115.08	117.47	136.24	180.33	204.96
EEI Electric Utilities Index	100.00	107.04	128.43	131.11	148.17	191.00

The foregoing performance graph and data shall not be deemed "filed" as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and shall not be deemed incorporated by reference into any other filing of IDACORP or Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars, except per share amounts and statistics)

	2014	2013	2012	2011	2010
Operating revenues	$1,282,524	$1,246,214	$1,080,662	$1,026,756	$1,036,029
Operating income	253,696	291,742	242,602	155,352	191,811
Net income attributable to IDACORP, Inc.	193,480	182,417	173,014	169,981	145,018
Diluted earnings per share	3.85	3.64	3.46	3.43	3.00
Dividends declared per share	1.76	1.57	1.37	1.20	1.20
Financial Condition:					
Total assets	5,716,853	5,364,563	5,291,290	4,925,319	4,635,304
Long-term debt (including current portion)	$1,615,502	$1,616,322	$1,537,696	$1,488,614	$1,610,859
Financial Statistics:					
Times interest charges earned:					
Before tax(1)	3.38	3.87	3.41	2.48	2.78
After tax(2)	3.19	3.06	3.02	3.00	2.69
Book value per share(3)	$ 38.85	$ 36.84	$ 34.73	$ 32.76	$ 30.51
Market-to-book ratio(4)	170%	141%	125%	129%	121%
Payout ratio(5)	46%	43%	40%	35%	40%
Return on year-end common equity(6)	9.9%	9.9%	9.9%	10.4%	9.6%

The financial statistics listed above are calculated in the following manner:

(1) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

(2) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

(3) Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

(4) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (3) above.

(5) Dividends paid per common share divided by diluted earnings per share.

(6) Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power. Also refer to "Cautionary Note Regarding Forward-Looking Statements" and Part I - Item 1A - "Risk Factors" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP's common stock is listed and trades on the New York Stock Exchange under the trading symbol "IDA". Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power provided electric service to approximately 516,000 general business customers as of December 31, 2014. As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC), the Public Utility Commission of Oregon (OPUC), and the Federal Energy Regulatory Commission (FERC). The IPUC and OPUC determine the rates that Idaho Power charges to its retail customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. As a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its open access transmission tariff (OATT). Idaho Power uses general rate cases, cost adjustment mechanisms, tariff riders, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-response programs, and to seek to earn a return on investment.

Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power's revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, availability of water for hydroelectric generation, price changes, customer usage patterns (which are affected in large part by the condition of the economy across the service territory), and the availability and price of purchased power and fuel. Idaho Power experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. IDACORP's and Idaho Power's financial condition are also affected by regulatory decisions through which Idaho Power seeks to recover its costs on a timely basis and earn an authorized return on investment, and by the ability to obtain financing through the issuance of debt and/or equity securities.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co., which is the former limited partner of, and successor by merger to, IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

EXECUTIVE OVERVIEW

Management's Outlook

In recent years Idaho Power has seen positive growth in its customer count and associated positive impacts on Idaho Power's revenue. To encourage responsible and sustainable growth, and as part of its planning for the future, Idaho Power actively participates in and supports state and local economic development initiatives. At the same time that Idaho Power pursues customer growth, it must also plan for that growth. Idaho Power's biennial Integrated Resource Plan (IRP) seeks to identify cost-effective and responsible means for Idaho Power to address future customer demand for electricity. Preparation of the 2015 IRP is underway and is expected to be completed by the end of the second quarter of 2015. Recent infrastructure investments and future anticipated infrastructure projects are intended to help Idaho Power both provide reliable service to existing customers and meet projected future customer growth. Idaho Power has invested significant capital in recent years to maintain and replace aging assets and to build for the future. Idaho Power expects to continue these significant levels of capital investment going forward. Idaho Power's noteworthy capital projects include the replacement of aging assets, upgrades to generation plants, a multi-year plan for replacement of underground conductor, ongoing system upgrades, and continued progress on permitting the Boardman-to-Hemingway and Gateway West 500-kV transmission lines. As of the date of this report, Idaho Power estimates total capital expenditures of approximately $1.5 billion over the next five years.

Idaho Power operates within what it believes to be a constructive regulatory framework, achieved through general rate cases, subject-specific rate filings, tariff riders, and cost recovery mechanisms that share risks and benefits with Idaho Power customers. To further complement these efforts, Idaho Power has also been focusing on controlling power supply, operating, maintenance, and capital costs through process review and improvement initiatives, and by empowering employees to identify new means to reduce costs, increase efficiencies, and enhance individual and enterprise performance for the benefit of IDACORP's shareholders, Idaho Power's customers, and other stakeholders. Based on its assessment, as of the date of this report Idaho Power does not expect to file an application for a general rate change in Idaho or Oregon during 2015.

Another area of recent focus has been IDACORP's dividend. In November 2011, IDACORP's board of directors adopted a target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings. From 2012 through 2014, IDACORP's board of directors has approved a collective 57 percent increase in the quarterly dividend, from $0.30 to $0.47 per share. Idaho Power's need and ability to construct infrastructure, the availability of timely regulatory recovery of costs associated with that construction, and IDACORP's earnings, among other factors discussed elsewhere in this report, all influence dividend decisions. A number of positive outcomes in those areas have been important elements that IDACORP's board of directors has considered in its recent dividend decisions.

2014 Accomplishments and 2015 Initiatives

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business. For the past several years, Idaho Power has been implementing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of IDACORP's and Idaho Power's achievements during 2014 under its three-part business strategy include:

- achieved net income growth for a seventh consecutive year;
- extended (with modifications) the December 2011 Idaho settlement stipulation to provide potential earnings support for 2015 through 2019;
- executed on business optimization initiatives, focusing on improving operations and controlling expenditures;
- managed through planned retirements, natural attrition, and business optimization, while scoring in the top quartile of a benchmark employee engagement survey;
- implemented Safety4Life—an initiative to increase employee safety awareness and improve employee safety behaviors and practices, and maintained Occupational Safety and Health Administration recordable injury rates well below utility industry national averages;
- continued progress toward the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects, including the issuance of the U.S. Bureau of Land Management's (BLM) draft environmental impact statement for the Boardman-to-Hemingway project in December 2014;
- remained on target to meet its goal to reduce average CO_2 emissions intensity by 10 to 15 percent below 2005 emissions for the six-year period 2010 through 2015; and
- improved Idaho Power's ranking from 29 to 17 in the annual "40 Best Energy Companies" list published by *Public Utilities Fortnightly*.

For 2015, in addition to its specific infrastructure and regulatory projects noted above, Idaho Power has established a number of organizational initiatives, including the following:

- emphasize and enhance its enterprise safety culture;
- actively manage costs and the ability to fund planned capital investments by optimizing business practices;
- continue innovative approaches to regulatory strategy;
- promote economic development through collaboration with the states of Idaho and Oregon to attract new businesses and expand existing businesses that utilize Idaho Power's available capacity and generation resources;
- focus on operational excellence through responsible resource planning, by matching resources to customer loads, managing the impacts of environmental regulations, maintaining Idaho Power's hydroelectric base, and enhancing power quality and reliability, and customer satisfaction;
- continue progress toward federal relicensing for the Hells Canyon Complex (HCC) hydroelectric facility and permitting of the 500-kV transmission projects;
- address issues related to the integration of renewable generation resources on the system grid;
- actively participate in the process for shaping carbon emission regulation for the electric utility industry; and
- address workforce attrition associated with anticipated retirements, using targeted succession planning and development programs.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by regulatory, operational, weather-related, economic, and other factors, many of which are described below.

Timely Regulatory Cost Recovery: The price that Idaho Power is authorized to charge for its electric service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Because of the significant impact of ratemaking decisions, and in furtherance of its goal of advancing a purposeful regulatory strategy, Idaho Power has focused on timely recovery of its costs through filings with the company's regulators, and on the prudent management of expenses and investments.

One of the most notable regulatory developments during 2014 was the IPUC's October 2014 approval of a regulatory settlement stipulation extending, with modifications, a December 2011 settlement stipulation that permitted Idaho Power to amortize additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum 9.5 percent Idaho-jurisdictional return on year-end equity (Idaho ROE) in 2012, 2013, and 2014, subject to prescribed limits and conditions. The October 2014 settlement stipulation allows for Idaho Power's amortization of up to a total of $45 million of additional ADITCs for the period from 2015 through 2019 to help achieve a minimum 9.5 percent Idaho ROE for an applicable year, subject to prescribed limits and conditions. Like the December 2011 settlement stipulation, the new settlement stipulation provides for the sharing between Idaho Power and Idaho customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. While providing no assurance that Idaho Power will obtain a 9.5 percent Idaho ROE in any of the years, IDACORP and Idaho Power believe the ability to amortize additional ADITC under the settlement stipulation provides an element of earnings stability for 2015 and potentially the next several years.

Another item that Idaho Power believes is representative of its active approach to regulatory matters was the IPUC's approval during 2014 of Idaho Power's request to shift recovery of approximately $99 million in Idaho-jurisdiction power supply expenses historically collected through the PCA mechanism to collection via base rates. While approval of the application results in no net change in the amount collected through base rates and the PCA mechanism in the aggregate, approval of the application will decrease the amount of any base rate increase requested in Idaho Power's next general rate case application filed with the IPUC.

The October 2014 settlement stipulation, base level power supply expense order, and other significant rate proceedings during 2012, 2013, and 2014 are described in "Regulatory Matters" in this MD&A. Important regulatory matters are also discussed in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Economic Conditions and Customer/Load Growth: Idaho Power monitors a number of economic indicators, including employment statistics, growth in customer numbers, foreclosure rates, and other housing-related data on a national and state scale and within Idaho Power's service territory. Economic conditions can impact consumer demand for electricity, collectability of accounts, the volume of off-system sales, and the need to construct and improve infrastructure, purchase power, and implement programs to meet customer load demands. Idaho Power has in recent years observed what it believes to be a number of positive economic factors in its service territory. For example:

- Based on Idaho Department of Labor preliminary data, the total number of persons employed in the service area in December 2014 was 459,531, compared with 452,666 in December 2013, and the associated unemployment rate for the service area was 3.6 percent, compared with 5.3 percent in December 2013. The U.S. rate stood at 5.6 percent in December 2014, according to U.S. Department of Labor data.
- Gross area product for Idaho Power's service area, as reported by Moody's Analytics, grew by 1.9 percent for 2014. Moody's forecasts, as of January 14, 2015, 3.1 percent and 3.5 percent growth in gross area product for 2015 and 2016, respectively.
- Customer growth from 2013 to 2014 was 1.4 percent.
- A number of businesses have recently constructed, or are in the process of constructing, sizable facilities in Idaho Power's service territory, including office and manufacturing complexes, particularly in the food processing industry.

Based on recent economic data, Idaho Power predicts that customer growth within its service area will continue to be positive. Idaho Power's most recent load forecast predicts a 1.4 percent five-year compound annual growth rate in residential loads and a 2.1 percent five-year compound annual growth rate in residential customers. For longer-term resource planning purposes, Idaho Power expects to include in its 2015 IRP, to be filed with the IPUC and OPUC in June 2015, a forecasted long-term annual residential customer growth rate of 1.6 percent, an increase over the 1.4 percent residential customer growth rate used in the 2013 IRP. These projected residential customer growth rates are improvements over the 1.0 percent growth rate experienced the past 5 years, but less than the 2.3 percent growth rate realized over the past 20 years.

Should the updated estimates of higher growth rates materialize, or if there is a significant increase in loads due to new, unanticipated large-load customers, growth would exceed the projections and Idaho Power could be required to adjust its infrastructure development timing and plans accordingly.

Weather Conditions and Associated Impacts: Weather and agricultural growing conditions have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy use for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters, irrigation customers use electricity to operate irrigation pumps, and weather conditions can impact the timing and degree of use of those pumps. Idaho Power also has tiered rates and seasonal rates, which contribute to increased revenues during higher-load periods, most notably during the third quarter of each year when overall customer demand is highest. In 2014, weather-related sales fluctuations were less dramatic than during the abnormally cold first quarter of 2013 and abnormally hot third quarter of 2013.

Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity. However, the availability and volume of hydroelectric power generated depends on several factors - the snow pack levels in the mountains upstream of Idaho Power's facilities, reservoir storage, springtime snow pack run-off, base flows in the Snake River, spring flows, rainfall, water leases and other water rights, and other weather and stream flow considerations. Idaho Power's hydroelectric generation during 2014 was 6.2 million megawatt-hours (MWh), compared with actual generation of 5.7 million MWh in 2013 and 8.0 million MWh in 2012. Since 1928, the resource-adjusted median annual hydroelectric generation is 8.5 million MWh. For 2015, Idaho Power estimates generation from its hydroelectric facilities of between 7.0 million MWh and 9.0 million MWh.

When hydroelectric generation is reduced, Idaho Power must rely on more expensive generation sources and purchased power. Most of the increase in power supply costs is collected from customers through the Idaho and Oregon PCA mechanisms. Conversely, in periods of greater hydroelectric generation most of the resulting decrease in power supply costs that typically occurs is returned to customers through the PCA mechanisms. When favorable hydroelectric generating conditions exist for Idaho Power, they also may exist for other Pacific Northwest hydroelectric facility operators – increasing the available supply of lower-cost power, lowering regional wholesale market prices, and impacting the revenue Idaho Power receives from off-system sales of its excess power. Conversely, when hydroelectric generating conditions are poor, wholesale market prices may be higher due to lower supply, but Idaho Power would generally have less surplus energy available for sale into the wholesale markets at those times. Much of the adverse or favorable impact of this volatility is addressed through the PCA mechanisms.

Fuel and Purchased Power Expense: In addition to hydroelectric generation, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities and power purchases in the wholesale markets. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's generation capacity, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. Operation of Idaho Power's Langley Gulch power plant, placed into operation in June 2012, has increased Idaho Power's use of natural gas as a generation fuel and thus its exposure to volatility in natural gas prices.

Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind or solar energy, and wholesale energy market prices. Idaho Power is required by law to purchase power from some PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will at times be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss. Softened market prices due to PURPA impacts also decrease Idaho Power's excess power sales. The proceeds from off-system sales lower overall power supply costs. Integration of intermittent, non-dispatchable resources (such as wind or solar energy) into Idaho Power's portfolio also creates a number of complex operational challenges and risks that Idaho Power must address. Notably, integration of these sources of power into Idaho Power's portfolio does not eliminate Idaho Power's need to construct facilities and infrastructure that provide reliable power. For instance, at the time Idaho Power reached its all-time system peak demand of 3,407 MW on July 2, 2013, wind resources on Idaho Power's system, representing roughly 675 MW of nameplate capacity, were contributing only 57 MW of power due to lack of wind. Increases in federally mandated PURPA power purchases have contributed to increases in customer rates.

The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power, including substantially all of the Idaho-jurisdiction PURPA power purchase costs. Idaho Power also uses physical and financial forward contracts for both electricity and fuel and other hedging strategies in order to manage the risks relating to fuel and power price exposures.

Regulatory and Environmental Compliance Costs: Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits by agencies and quasi-governmental agencies, including the FERC and the North American Electric Reliability Corporation. Compliance with these requirements directly influences Idaho Power's operating environment and affects Idaho Power's operating costs. Potential fines and monetary awards that result from a violation of, and costs associated with operational changes that are necessary to comply with, applicable laws or regulations may be substantial. Accordingly, Idaho Power has in place numerous compliance policies and initiatives to help ensure compliance, and periodically evaluates and updates those policies and initiatives.

Environmental laws and regulations in particular may, among other things, increase the cost of operating generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power cease operating certain generation plants. For instance, the Boardman coal-fired power plant, in which Idaho Power owns a 10-percent interest, is scheduled to cease coal-fired operations by the end of 2020, the decision for which was driven in large part by the substantial cost of environmental controls required by existing regulations. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade. As legislation and regulations concerning greenhouse gas emissions develop, including the proposed rule under Section 111(d) of the Clean Air Act, Idaho Power will continue to actively participate in the rulemaking process.

Other Notable Matters and Areas of Focus

Water Management and Relicensing of the Hells Canyon Hydroelectric Project: Because of Idaho Power's reliance on stream flow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for use at its hydroelectric projects. Also, Idaho Power is involved in renewing its federal license for the HCC, its largest hydroelectric generation source. Relicensing involves numerous environmental issues and substantial costs. Idaho Power is working with the states of Idaho and Oregon, federal and state regulatory authorities, and interested parties to address concerns and take appropriate measures relating to the relicensing of the HCC. However, given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial, and the terms of, and costs associated with, any resulting license are not currently determinable.

Transmission Projects: Idaho Power continues to focus on expansion of its transmission system in an effort to enhance system reliability and access to wholesale markets. Its most notable transmission projects in progress are the proposed Boardman-to-Hemingway and Gateway West 500-kV transmission projects. In January 2012, Idaho Power entered into cost-sharing arrangements with third parties for the permitting phases of both projects. Construction of these projects cannot commence until all federal, state, and local regulatory requirements are met. As it relates to the Boardman-to-Hemingway project, for which Idaho Power is the project manager, environmental requirements and regulations (particularly relating to sage grouse) for the siting process have changed significantly since commencement of the project, making permitting for the transmission line more difficult. This has resulted in project delays and increased permitting costs. In light of the delays and siting impediments that have occurred and are expected to continue, Idaho Power estimates that the in-service date for the Boardman-to-

Hemingway line would be 2021 or beyond. The Boardman-to-Hemingway line remains Idaho Power's preferred resource alternative, as identified in Idaho Power's 2013 IRP.

Summary of 2014 Financial Results

The following is a summary of Idaho Power's net income, net income attributable to IDACORP, and IDACORP's earnings per diluted share for the years ended December 31, 2014, 2013, and 2012 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2014	**2013**	**2012**
Idaho Power net income	$ 189,387	$ 176,741	$ 168,168
Net income attributable to IDACORP, Inc.	$ 193,480	$ 182,417	$ 173,014
Average outstanding shares – diluted (000's)	50,199	50,126	50,010
IDACORP, Inc. earnings per diluted share	$ 3.85	$ 3.64	$ 3.46

The table below provides a reconciliation of net income attributable to IDACORP, Inc. for year ended December 31, 2014 to the year ended December 31, 2013 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2013		**$ 182.4**
Change in Idaho Power net income:		
Decreased sales volumes attributable to usage per customer, net of associated power supply costs and PCA mechanism impacts	$ (38.1)	
Increased sales volumes attributable to customer growth, net of associated power supply costs and PCA mechanism impacts	9.1	
Increased labor-related expenses	(4.6)	
Increased depreciation, property tax, and other (net)	(3.8)	
Greater sharing-related costs reflected as pension expense and revenue sharing	(0.6)	
Decrease in Idaho Power operating income	(38.0)	
Increase in allowance for funds used during construction (AFUDC)	3.9	
Gains on sale of investments in 2013, not repeated in 2014	(11.6)	
Changes in other non-operating income and expenses	1.6	
Decreased income taxes due to tax method changes for years prior to 2014	29.1	
Decreased income taxes due to greater capitalized repairs deduction in 2014	7.8	
Decreased other income tax expense	19.8	
Total increase in Idaho Power net income		12.6
Other net changes (net of tax)		(1.5)
Net income attributable to IDACORP, Inc. - December 31, 2014		**$ 193.5**

IDACORP's net income increased $11.1 million for the year ended December 31, 2014 when compared with 2013. Idaho Power's operating income decreased by $38.0 million for 2014 compared with 2013. Lower overall usage per customer, primarily due to a return to moderate weather conditions in 2014 compared with 2013, decreased operating income by $38.1 million. These weather-related decreases were partially offset by increased sales volumes associated with continued growth in the number of Idaho Power customers, which increased operating income by $9.1 million when compared with 2013. The number of Idaho Power's general business customers increased by 1.4 percent from December 31, 2013 to December 31, 2014. Increases in labor-related expenses, depreciation, property taxes, and other items combined to decrease operating income by $8.4 million in 2014 when compared with 2013.

In 2014, Idaho Power recorded a $3.9 million increase in AFUDC related to greater average construction work in progress, while in 2013 it recorded a gain of $11.6 million related to the sale of investments in securities that was not repeated in 2014. The net decrease in income tax expense of $56.7 million more than offset the lower pre-tax income in 2014.

Effect of Income Taxes and Tax Method Changes on Results

Income tax accounting method changes for years prior to 2014 increased net income by $29.1 million for 2014 when compared with 2013. In 2013, Idaho Power recorded $4.6 million of income tax expense as a result of a cumulative method change adjustment related to its capitalized repairs deduction for generation assets for years prior to 2013. By contrast, during 2014, Idaho Power recorded an income tax benefit of $24.5 million related to finalization of its method change adjustment for generation assets for years prior to 2014 as well as modifications to its overall capitalized repairs deduction tax method as agreed to with the U.S. Internal Revenue Service (IRS). The income tax benefit related to Idaho Power's 2014 capitalized repairs deduction was $7.8 million greater than 2013, due to the impact of the method changes and the amount and type of 2014 capital additions. Income tax expense at Idaho Power not related to method changes was $19.8 million lower in 2014 than in 2013, primarily due to lower pre-tax earnings in 2014.

Effect of Sharing Mechanism on Results

During 2014, Idaho Power recorded a total of $24.7 million related to a December 2011 Idaho regulatory settlement agreement, which requires sharing with Idaho customers of a portion of 2014 earnings exceeding a 10.0 percent Idaho ROE. In accordance with the terms of the settlement agreement, of the $24.7 million, $16.7 million was recorded as additional pension expense and $8.0 million was recorded as a provision against current revenues to be refunded to customers through a future rate reduction. Idaho Power recorded similar amounts in 2013. A total of $118 million in earnings has been shared with Idaho customers through sharing mechanisms since 2009. The settlement agreement is described further in "Regulatory Matters" in this MD&A. The impact of sharing on 2014 and 2013 results is reflected in the following table (in millions):

	2014	2013	Variance
Additional pension expense funded through sharing	$ (16.7)	$ (16.5)	$ (0.2)
Provision against current revenue as a result of sharing	(8.0)	(7.6)	(0.4)
Total	$ (24.7)	$ (24.1)	$ (0.6)

Key Operating and Financial Metric Estimates for 2015

IDACORP's and Idaho Power's estimates, as of the date of this report, for 2015 metrics are as follows:

	2015 Estimate	2014 Actual
Idaho Power Operating & Maintenance Expense (millions)	$340-$350	$ 355
Idaho Power Additional Amortization of ADITC (millions)	None	None
Idaho Power Capital Expenditures, excluding AFUDC (millions)	$300-$310	$ 265
Idaho Power Hydroelectric Generation (MWh)	7.0-9.0	6.2

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and Idaho Power's earnings. In this analysis, the results for 2014 are compared with 2013 and the results for 2013 are compared with 2012. In the MD&A, MWh and dollar amounts in tables, other than earnings per share, are in thousands unless otherwise indicated.

Utility Operations

The table below presents Idaho Power's energy sales and supply (in thousands of MWh) for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
General business sales	14,092	14,619	14,085
Off-system sales	2,220	1,683	2,183
Total energy sales	16,312	16,302	16,268
Hydroelectric generation	6,170	5,656	7,956
Coal generation	5,851	6,327	5,227
Natural gas and other generation	1,175	1,576	676
Total system generation	13,196	13,559	13,859
Purchased power	4,153	3,902	3,670
Line losses	(1,037)	(1,159)	(1,261)
Total energy supply	16,312	16,302	16,268

Sales Volume and Generation: In 2014, general business sales volume decreased by 0.5 million MWh, or 4 percent, compared with the prior year, mostly related to decreased residential customer usage attributable to more moderate weather conditions in 2014 compared with 2013. Industrial customer usage increased when compared with the prior year, partially offsetting the overall decrease in general business sales volumes. Off-system sales volume increased by 0.5 million MWh, or 32 percent, in 2014 as small increases in output from hydroelectric resources, a decrease in general business customer load, and favorable wholesale market conditions increased surplus power available for sale.

Hydroelectric generation provided 47 percent of Idaho Power's total system generation during 2014. Hydroelectric generation in 2014 was 73 percent of the annual median generation of 8.5 million MWh, which is based on median hydrologic conditions as derived from the Snake River Basin historical stream flow record normalized to reflect the current level of water resource development. The below-average hydroelectric generation during 2012 through 2014 resulted from relatively low snow pack and spring season run-off in the Snake River basin during the three-year period.

The small increase in hydroelectric generation during 2014 compared with 2013 contributed to decreased utilization of coal-fired and natural-gas fired generation.

The financial impacts of fluctuations in off-system sales, purchased power, fuel expense, and other power supply-related expenses are addressed in Idaho Power's Idaho and Oregon PCA mechanisms, which are described later in this MD&A.

General Business Revenues**:** The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the last three years:

	Year Ended December 31,		
	2014	2013	2012
Revenue			
Residential	$ 500,195	$ 513,914	$ 431,555
Commercial	299,462	281,009	241,519
Industrial	182,675	165,941	145,054
Irrigation	158,654	159,242	137,424
Total	1,140,986	1,120,106	955,552
Provision for sharing	(7,999)	(7,602)	(7,151)
Deferred revenue related to HCC relicensing AFUDC[1]	(10,706)	(10,776)	(10,636)
Total general business revenues	$ 1,122,281	$ 1,101,728	$ 937,765
Volume of Sales (MWh)			
Residential	4,965	5,365	5,039
Commercial	3,944	3,975	3,865
Industrial	3,217	3,182	3,133
Irrigation	1,966	2,097	2,048
Total MWh sales	14,092	14,619	14,085
Number of customers at year-end			
Residential	428,294	422,188	416,020
Commercial	67,522	66,734	65,920
Industrial	121	115	119
Irrigation	19,826	19,398	19,045
Total customers	515,763	508,435	501,104

[1] As part of its January 30, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the HCC relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power expects to collect approximately $10.7 million annually in the Idaho jurisdiction, but is deferring revenue recognition of the amounts collected until the license is issued and the asset is placed in service under the new license.

Changes in rates and changes in customer demand are the primary causes of fluctuations in general business revenue from period to period. See "Regulatory Matters" in this MD&A for a list of rate changes implemented over the last three years. The primary influence on changes in customer demand for electricity is weather conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, while moderate temperatures decrease sales. Precipitation levels and the timing of precipitation during the agricultural growing season affect sales to customers who use electricity to operate irrigation pumps. Rates are seasonally adjusted and based on a tiered rate structure that provides for higher rates during peak load periods. These seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings. For purposes of illustration and comparison, Boise, Idaho weather-related information for the last three years is presented in the following table:

	Year Ended December 31,			
	2014	2013	2012	Normal
Heating degree-days[1]	4,976	6,032	4,723	5,514
Cooling degree-days[1]	1,129	1,320	1,274	942

[1] Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. While Boise, Idaho weather conditions are not necessarily representative of weather conditions throughout Idaho Power's service territory, the greater Boise area has the majority of Idaho Power's customers.

General Business Revenues - 2014 Compared with 2013: General business revenue increased $20.6 million in 2014 compared with 2013. The factors affecting general business revenues are discussed below.

- Rates. Rate changes, primarily associated with increased power supply costs, combined to increase general business revenue by $64.8 million. The revenue impact of the rate changes was partially offset by associated changes in operating expenses—Idaho PCA amortization expense increased $42.8 million in 2014 due to the change in the corresponding Idaho PCA true-up rate in the current year. The PCA mechanism is discussed later in this MD&A.

- Usage. Lower usage per customer, primarily driven by the impact of more moderate weather during 2014 on residential customer usage, decreased general business revenue by $55.7 million. Residential usage per customer was 9.1 percent lower in 2014.

- Customers. Continued customer growth partially offset the decrease in overall MWh sales, increasing revenue by $11.9 million. Customer growth from 2013 to 2014 was 1.4 percent.

- Sharing. The overall increase in general business revenue was impacted by Idaho Power's revenue sharing mechanism. This mechanism, which was in place for 2012 through 2014, is associated with the December 2011 Idaho regulatory settlement agreement that provides for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. The impact of this mechanism is partially recorded as a reduction to general business revenue. Reductions of $8.0 million and $7.6 million were recorded in 2014 and 2013, respectively, resulting in a net decrease to general business revenue of $0.4 million in 2014.

General Business Revenues - 2013 Compared with 2012: General business revenue increased $164.0 million in 2013 compared with 2012. The factors affecting general business revenues are discussed below.

- Rates. Rate changes, primarily associated with increased power supply costs, combined to increase general business revenue by $130.8 million. The revenue impact of several of the rate changes was directly offset by associated changes in operating expenses. For example, Idaho PCA amortization expense increased $42.0 million in 2013 due to the change in the corresponding Idaho PCA true-up rate in the current year.

- Usage. Higher usage per customer, primarily driven by residential customers, increased general business revenue by $27.9 million. While usage increased across all customer classes, residential usage per customer was 5.2 percent higher for 2013 due largely to more extreme summer and winter temperatures.

- Customers. Customer growth contributed to the increase in overall MWh sales, increasing revenue $12.3 million. Customer growth from 2012 to 2013 was 1.5 percent. The positive impact of customer growth was partially offset by a $6.6 million decrease in revenues resulting from the termination in 2012 of an electric service agreement with Hoku Materials, Inc. Combined, these changes increased general business revenues by $5.7 million.

- Sharing. The overall increase in general business revenue was impacted by Idaho Power's revenue sharing mechanism under the December 2011 Idaho regulatory settlement agreement noted above. Reductions of $7.6 million and $7.2 million were recorded in 2013 and 2012, respectively, resulting in a net decrease to general business revenue of $0.4 million in 2013.

***Off-System Sales*:** Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
Revenue	$ 77,165	$ 54,473	$ 61,534
MWh sold	2,220	1,683	2,183
Revenue per MWh	$ 34.76	$ 32.37	$ 28.19

Off-System Sales - 2014 Compared with 2013: Off-system sales revenue increased by $22.7 million, or 42 percent, in 2014 as a result of favorable market conditions, at times, for selling power off-system. Off-system sales volumes also benefitted from greater amounts of surplus system energy resulting from slightly lower system loads and increased hydroelectric generation and PURPA power purchases.

Off-System Sales - 2013 Compared with 2012: Off-system sales revenue decreased by $7.1 million, or 11 percent, in 2013 as a result of lower volumes of surplus power available for sale. Sales volumes decreased by 23 percent due to lower output from hydroelectric plants due to unfavorable hydroelectric generating conditions (as a result of lower snow pack and spring season run-off) and an increase in general business customer loads.

Other Revenues: The table below presents the components of other revenues for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
Transmission services and other	$ 52,051	$ 51,260	$ 50,126
Energy efficiency	27,154	35,637	27,300
Total other revenues	$ 79,205	$ 86,897	$ 77,426

Other Revenues - 2014 Compared with 2013: Other revenues decreased $7.7 million in 2014, resulting primarily from an order issued by the IPUC in the prior year that allowed Idaho Power to recover custom efficiency program incentive payments made between January 1, 2011 and June 1, 2013, through the energy efficiency rider. Based on the order, $14.3 million of other revenue (as well as energy efficiency program expense) was recognized in the second quarter of 2013. Partially offsetting the impact of this order from the IPUC was higher utilization of energy efficiency programs when compared with 2013.

Most energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings.

Other Revenues - 2013 Compared with 2012: Other revenues increased $9.5 million in 2013, mainly due to an increase in energy efficiency revenues of $8.3 million, due to an order issued by the IPUC allowing Idaho Power to recover custom efficiency program incentive payments between January 1, 2011 and June 1, 2013, through the energy efficiency rider. Based on the order, $14.3 million of other revenue (as well as energy efficiency program expense) was recognized in the second quarter of 2013. The impact of the order was offset by decreased utilization of demand response programs during 2013.

Purchased Power: The table below presents Idaho Power's purchased power expenses and volumes for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
Expense			
PURPA contracts	$ 144,617	$ 131,338	$ 117,618
Other purchased power (including wheeling)	92,071	85,038	64,838
Demand response incentive payments	7,940	4,203	14,479
Total purchased power expense	$ 244,628	$ 220,579	$ 196,935
MWh purchased			
PURPA contracts	2,286	2,127	1,961
Other purchased power	1,867	1,775	1,709
Total MWh purchased	4,153	3,902	3,670
Cost per MWh from PURPA contracts	$ 63.26	$ 61.75	$ 59.98
Cost per MWh from other purchased power	$ 49.31	$ 47.91	$ 37.94
Weighted average - all sources (excluding demand response incentive payments)	$ 56.99	$ 55.45	$ 49.72

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase more power during heavy load periods than during light load periods, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Market energy prices are typically higher during heavy load periods than during light load periods. Also, in accordance with Idaho Power's risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transaction prices. Most of the non-PURPA purchased power and substantially all of the PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms.

Purchased Power - 2014 Compared with 2013: Purchased power expense increased $24.0 million, or 11 percent, in 2014, mostly resulting from an increase in generation provided by PURPA wind contracts when compared with 2013. In addition, wholesale gas and electricity market conditions warranted third-party power purchases to serve system load at times rather than dispatching Idaho Power-owned thermal resources. Finally, the increases in demand response program incentive payments primarily relate to the temporary cessation of some of these programs during 2013, which were reinstated for 2014.

Purchased Power - 2013 Compared with 2012: Purchased power expense increased $23.6 million, or 12 percent, in 2013, principally due to additional PURPA wind generation that came on-line, as well as less favorable hydroelectric generating conditions, which increased the need to purchase power from third parties. The volume of power purchased through PURPA contracts increased 8 percent, contributing to a $13.7 million increase in PURPA power purchase expense in 2013, while MWh purchased through other sources increased 4 percent. Reductions in demand response program costs, due to temporary suspension of two programs in 2013, partially offset the increased expenses related to power purchases.

***Fuel Expense*:** The table below presents Idaho Power's fuel expenses and generation at its thermal generating plants for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
Expense			
Coal	$ 156,172	$ 160,277	$ 134,501
Natural gas and other thermal	45,069	54,205	24,912
Total fuel expense	$ 201,241	$ 214,482	$ 159,413
MWh generated			
Coal	5,851	6,327	5,227
Natural gas and other thermal	1,175	1,576	676
Total MWh generated	7,026	7,903	5,903
Cost per MWh			
Coal	$ 26.69	$ 25.33	$ 25.73
Natural gas and other thermal	38.36	34.39	36.85
Weighted average, all sources	$ 28.64	$ 27.14	$ 27.01

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh are noticeably impacted by these fixed charges when generation output is substantially different between the periods.

Fuel Expense - 2014 Compared with 2013: In 2014, fuel expense decreased $13.2 million, or 6 percent, compared with 2013, due principally to decreased output from the natural gas-fired plants during 2014, resulting from lower system load demands and increased generation provided by facilities under PURPA contracts. The thermal coal plants were also operated less in 2014 when compared with 2013, as higher hydroelectric generation enabled lower utilization of the coal plants to serve system load requirements. Partially offsetting these decreases were higher commodity costs when compared with 2013.

Fuel Expense - 2013 Compared with 2012: In 2013, fuel expense increased $55.1 million, or 35 percent, compared with 2012, due principally to the following factors:

- Idaho Power's Langley Gulch natural gas-fired power plant came on line on June 29, 2012. Operation of the plant accounted for $23.9 million of the increase in fuel expense. Idaho Power operated the plant primarily to serve peak load, to integrate intermittent resources, and for economic dispatch opportunities. During 2013, Idaho Power relied more on Langley Gulch and other gas plants to meet customer loads as a result of the decline in hydroelectric generation compared with the same period in 2012; and
- generation from coal-fired facilities increased 21 percent in 2013. This increase in generation accounted for $25.6 million of the increase in fuel expense compared with 2012. During 2013, higher wholesale power prices and lower

hydroelectric generation when compared with 2012 increased Idaho Power's reliance on its coal-fired plants to meet customer loads.

***PCA Mechanisms*:** Idaho Power's power supply costs (primarily purchased power and fuel, less off-system sales) can vary significantly from year to year. Volatility of power supply costs arises from factors such as weather conditions, wholesale market prices and volumes of power purchased and sold in the wholesale markets, Idaho Power's hydroelectric and thermal generation volumes and fuel costs, generation plant availability, and retail loads. To address the volatility of power supply costs, Idaho Power's PCA mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. In the Idaho jurisdiction, the PCA includes a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and the company (5 percent), with the exception of PURPA power purchases and demand-response program incentives, which are allocated 100 percent to customers. Because of the PCA mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers in a future period, resulting in fluctuations in operating cash flows from year to year. The table that follows presents the components of the Idaho and Oregon PCA mechanisms for the last three years:

	Year Ended December 31,		
	2014	**2013**	**2012**
Idaho power supply cost deferral	$ (48,104)	$ (67,127)	$ (45,064)
Oregon power supply cost deferral	—	—	(1,523)
Amortization of prior year authorized balances	70,339	27,590	(14,503)
Total power cost adjustment expense	$ 22,235	$ (39,537)	$ (61,090)

The power supply deferrals represent the portion of the power supply cost fluctuations deferred under the PCA mechanisms. When actual power supply costs are higher than the amount forecasted in PCA rates, which was the case for 2014, 2013, and 2012, most of the difference is deferred. The amortization of the prior year's balances represents the offset to the amounts being collected or refunded in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2014 Compared with 2013: Actual net power supply cost deferrals decreased in 2014 relative to 2013, a change of $19.0 million—from $67.1 million to $48.1 million. Power supply costs collected through base rates increased on June 1, 2014, resulting in less costs needing to be recovered through the PCA mechanism since that time. The $70.3 million of amortization offsets the collection from customers of prior years' deferrals.

PCA Mechanisms - 2013 Compared with 2012: Actual net power supply cost deferrals increased in 2013 relative to 2012, a change of $20.5 million—from deferrals of $46.6 million to $67.1 million. The $27.6 million of amortization offsets the net collection from customers of prior years' deferrals.

***Other Operations and Maintenance Expenses*:** The changes in operations and maintenance (O&M) expenses for the periods presented are discussed below.

O&M - 2014 Compared with 2013: Other O&M expense increased by $5.7 million in 2014 compared with 2013, an increase of less than two percent, due to the following factors:

- an increase of $4.6 million in labor-related expenses, caused by normal escalations in labor and benefits costs; and
- an increase of $0.9 million in bad debt expense resulting from fewer collections related to a billing system change made in 2013. Due to full implementation of the billing system change, Idaho Power expects that bad debt expense will return to more normal levels in future periods.

O&M - 2013 Compared with 2012: Other O&M expense decreased by $0.2 million in 2013 compared with 2012, a decrease of less than one percent, due to the following factors:

- pension expense increased $1.9 million as the sharing mechanism in place during both years resulted in higher sharing-related pension expense in 2013;
- other O&M expenses were $1.3 million lower, reflecting business optimization efforts;
- labor-related expenses increased by $1.5 million as a result of normal escalations in labor and benefits costs; and

- O&M expenses associated with hydroelectric generation were $2.3 million lower, primarily due to water lease payments made in 2012 that were not made in 2013 because less water associated with these leases was available in 2013.

Gain on Sale of Investments

In 2013, Idaho Power recognized an $11.6 million gain on the sale of marketable securities. These investments relate to the Rabbi trust designated to provide funding for Idaho Power's obligations under its Security Plan for Senior Management Employees. Gross proceeds from the sale were $25.7 million. No such sale occurred in 2014 or 2012.

Income Taxes

Income tax accounting method changes decreased 2014 income tax expense by $29.1 million when compared with 2013. In 2013, Idaho Power recorded $4.6 million of income tax expense as a result of a method change related to its capitalized repair deduction for generation assets for years prior to 2013. By contrast, in 2014, Idaho Power, in coordination with the IRS through IDACORP's Compliance Assurance Process program, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission, and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in 2014. Idaho Power finalized these changes with the filing of IDACORP's 2013 consolidated federal income tax return in September 2014. In 2014, Idaho Power also recorded a $13.4 million for years prior to 2013 income tax benefit for the finalization of the cumulative method change impact related to the generation asset method change. The income tax benefit related to Idaho Power's 2014 capitalized repairs deduction was $7.8 million greater than 2013, due to the impact of the method changes and the amount and type of 2014 capital additions. Further, income tax expense (excluding the tax method changes) decreased $19.8 million compared with 2013, principally due to lower Idaho pre-tax earnings in 2014. Income tax expense in 2013 increased significantly compared with 2012, principally as a result of greater Idaho Power pre-tax earnings in 2013.

On August 18, 2014, the U.S. Treasury and IRS issued final regulations addressing the disposition of property subject to depreciation and general asset accounts. The regulations are generally effective for tax years beginning on or after January 1, 2014. IDACORP and Idaho Power do not believe these disposition regulations will have a material adverse effect on future tax filings. Therefore, as of December 31, 2014, no income tax impacts have been recorded related to the new guidance.

For additional information relating to IDACORP's and Idaho Power's income taxes, including the availability of tax credit carryforwards, see Note 2 - "Income Taxes" to the consolidated financial statements included in this report.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Idaho Power has been pursuing significant enhancements to its utility infrastructure in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and component replacement. Idaho Power's expenditures for property, plant and equipment, excluding AFUDC, were $265 million in 2014 and $228 million in 2013. Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of approximately $1.5 billion over the period from 2015 through 2019.

Idaho Power funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. Idaho Power periodically files for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators. Idaho Power uses operating and capital budgets to control operating costs and capital expenditures, and has also been focusing on optimizing its business operations, which has included controlling operating and maintenance costs through process review and improvement initiatives. Consistent with 2014, during 2015 IDACORP and Idaho Power will continue to focus on optimizing operations, controlling costs, and generating sufficient operating cash inflows to meet operating expenditures, contribute to capital expenditure requirements, and pay dividends to shareholders.

As of February 13, 2015, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- $125 million and $300 million revolving credit facilities, respectively;
- IDACORP's shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) on May 22, 2013, which may be used for the issuance of debt securities and common stock, including up to 3 million shares of IDACORP common stock available for issuance under IDACORP's sales agency agreement executed in July 2013;
- Idaho Power's shelf registration statement, filed with the SEC jointly with IDACORP on May 22, 2013, which may be used for the issuance of first mortgage bonds and debt securities; $500 million is available for issuance under a selling agency agreement executed in July 2013 and pursuant to state regulatory authority; and
- IDACORP's and Idaho Power's issuance of commercial paper, which may be issued up to an amount equal to the available credit capacity under their respective credit facilities.

IDACORP and Idaho Power have no significant long-term debt maturities until 2018. Based on planned capital expenditures and operating and maintenance expenses for 2015, the companies believe they will be able to meet capital requirements and fund corporate expenses during 2015 with a combination of existing cash and operating cash flows generated by Idaho Power's utility business, together with proceeds from either draws upon credit facilities or Idaho Power's issuance of debt securities. IDACORP and Idaho Power would expect to meet any short-term cash shortfalls during 2015 with existing credit facilities and expect to continue to manage short-term liquidity through commercial paper markets.

IDACORP and Idaho Power also monitor capital markets with a view toward opportunistic debt and equity transactions, taking into account current and potential long-term future needs. As a result, IDACORP may issue debt securities or may issue common stock under the existing continuous equity program, and Idaho Power may issue debt securities, if the companies believe terms available in the capital markets are favorable and that issuances would be financially prudent. Idaho Power also periodically analyzes whether partial or full early redemption of one or more existing outstanding series of first mortgage bonds is desirable, and in some cases may refinance indebtedness with new indebtedness issued with more favorable terms, including interest rates lower than the series being redeemed.

IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2014, IDACORP's and Idaho Power's capital structures were as follows:

	IDACORP	**Idaho Power**
Debt	46%	47%
Equity	54%	53%

IDACORP and Idaho Power generally maintain their cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills, money market funds, and bank deposits.

Operating Cash Flows

IDACORP's and Idaho Power's principal sources of cash flows from operations are Idaho Power's sales of electricity and transmission capacity. Significant uses of cash flows from operations include the purchase of fuel and power, other operating expenses, interest, and pension plan contributions. Operating cash flows can be significantly influenced by factors such as weather conditions, rates and the outcome of regulatory proceedings, and economic conditions. As fuel and purchased power are significant uses of cash, Idaho Power has regulatory mechanisms in place that provide for the deferral and recovery of the majority of the fluctuation in those costs. However, if actual costs rise above the level allowed in retail rates, deferral balances increase (reflected as a regulatory asset), negatively affecting operating cash flows until such time as those costs, with interest, are recovered from customers.

IDACORP’s and Idaho Power’s operating cash inflows in 2014 were $364 million and $343 million, respectively, increases of $59 million and $53 million, respectively, compared with 2013. Significant items that affected the companies' operating cash flows in 2014 relative to 2013 included:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply costs deferred and collected under the Idaho PCA mechanism, increased operating cash inflows by $58 million;
- changes in working capital balances due primarily to timing. Decreases in receivable balances from 2013 to 2014 compared with the increase in receivable balances experienced from 2012 to 2013 resulted in an increase to cash flows for 2014 of approximately $50 million for IDACORP and $52 million for Idaho Power;

- cash outflows related to income taxes increased by approximately $10 million for IDACORP and $16 million for Idaho Power from 2013 to 2014; and
- Idaho Power's joint venture, BCC, made net distributions to Idaho Power of $4 million in 2014, as compared with $15 million in 2013. A build-up in coal inventories at BCC during 2014 reduced BCC's cash available for distribution.

IDACORP's and Idaho Power's operating cash inflows in 2013 were $306 million and $290 million, respectively, increases of $56 million and $32 million, respectively, compared with 2012. In addition to increased pre-tax earnings, significant items that affected the companies' operating cash flows in 2013 relative to 2012 included:

- Idaho Power made $30 million of cash contributions to its defined benefit pension plan in 2013, compared with $44 million of cash contributions during 2012;
- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply costs deferred and collected under the Idaho PCA mechanism, increased operating cash inflows by $28 million;
- cash outflows related to income taxes increased by approximately $25 million for Idaho Power from 2012 to 2013 and cash outflows related to incomes taxes remained relatively flat at $1 million for IDACORP between 2012 and 2013; and
- changes in working capital balances due primarily to timing. Increases in receivable balances reduced cash flows by approximately $27 million, primarily as a result of increased year-end sales in 2013 compared with 2012. Fluctuations in accounts payables and other accrued liabilities reduced cash flows by $11 million, largely as a result of reduced accruals for PURPA-related payables. Other current liabilities increased cash flows by $10 million primarily due to customer deposits returned in 2012.

Investing Cash Flows

Investing activities consist primarily of capital expenditures related to new construction and improvements to Idaho Power’s generation, transmission, and distribution facilities. Idaho Power's construction expenditures, including AFUDC, were $274 million, $235 million, and $240 million in 2014, 2013, and 2012, respectively. These capital expenditures were primarily for construction of utility infrastructure needed to address Idaho Power’s aging plant and equipment, customer growth, and environmental and regulatory compliance requirements.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, managing commodity price risk, and other financial commitments through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho Power, and non-utility operating expenses through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities. The following are significant items and transactions that affected financing cash flows in 2012, 2013, and 2014:

- on April 13, 2012, Idaho Power issued $75 million in principal amount of 2.95% first mortgage bonds due 2022 and $75 million in principal amount of 4.30% first mortgage bonds due 2042;
- in May 2012, Idaho Power redeemed prior to maturity $100 million of 4.75% first mortgage bonds due in November 2012;
- on April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds due 2023 and $75 million in principal amount of 4.00% first mortgage bonds due 2043;
- on October 1, 2013 Idaho Power repaid at maturity $70 million of its 4.25% first mortgage bonds;
- IDACORP and Idaho Power paid dividends of approximately $88 million, $79 million, and $69 million in 2014, 2013, and 2012, respectively;
- Idaho Power received capital contributions of $8 million from IDACORP in 2012; and
- IDACORP's net change in commercial paper borrowings was a reduction of $23 million and $15 million in 2014 and 2013, respectively, and an increase of $16 million in 2012.

Financing Programs and Available Liquidity

IDACORP Equity Programs: On July 12, 2013, IDACORP entered into a Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM), under which IDACORP may offer and sell up to 3 million shares of its common stock from time to time through BNYMCM as IDACORP's agent. IDACORP has no obligation to sell any minimum number of shares under the

Sales Agency Agreement. As of the date of this report, 3 million shares of IDACORP common stock remain available for sale under the Sales Agency Agreement with BNYMCM.

Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases of IDACORP common stock for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. However, IDACORP may determine at any time to resume original issuances of common stock under those plans. As noted above, an important component of that determination will be IDACORP's and Idaho Power's capital structure. Under the dividend reinvestment and employee-related stock purchase plans in effect prior to July 1, 2012, IDACORP issued 111,380 shares in 2012 for proceeds of $4.5 million.

Idaho Power First Mortgage Bonds: Idaho Power's issuance of long-term indebtedness is subject to the approval of the IPUC, OPUC, and Wyoming Public Service Commission (WPSC). In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC is through April 9, 2015, though Idaho Power may request an extension by letter filed with the IPUC prior to that date. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a maximum interest rate limit of seven percent.

On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million in aggregate principal amount of first mortgage bonds, Series J (Series J Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes. As of the date of this report, Idaho Power has not sold any first mortgage bonds or debt securities under the Selling Agency Agreement.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture, market conditions, regulatory authorizations, and covenants contained in other financing agreements.

The Indenture limits the maximum amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2014 was limited to approximately $409 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust. Separately, the Indenture also limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture. As of December 31, 2014, Idaho Power could issue approximately $1.6 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

Refer to Note 4 - “Long-Term Debt” to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

***IDACORP and Idaho Power Credit Facilities*:** IDACORP and Idaho Power have $125 million and $300 million credit facilities, respectively. Each of the credit facilities may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $125 million at any one time outstanding, including swingline loans not to exceed $15 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating, as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 65 percent as of the end of each fiscal quarter. In determining the leverage ratio, “consolidated indebtedness” broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). “Consolidated total capitalization” is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2014, the leverage ratios for IDACORP and Idaho Power were 46 percent and 47 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities, which could limit the ability of the companies to issue first mortgage bonds and debt securities. There are additional covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments, restrict the creation of certain liens, and prohibit entering into any agreements restricting dividend payments from any material subsidiary. At December 31, 2014, IDACORP and Idaho Power believe they were in compliance with all facility covenants. Further, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2015.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

In October 2013, IDACORP and Idaho Power executed agreements with the lenders, extending the maturity date under both credit agreements to October 26, 2018. No other terms of the credit agreements, including the amount of permitted borrowings under the credit agreements, were affected by the extension.

Without additional approval from the IPUC, the OPUC, and the WPSC, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

IDACORP and Idaho Power Commercial Paper: IDACORP and Idaho Power have commercial paper programs under which they issue unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time not to exceed the available capacity under their respective credit facilities, described above. IDACORP's and Idaho Power's credit facilities are available to the companies to support borrowings under their commercial paper programs. The commercial paper issuances are used to provide an additional financing source for the companies' short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Individual instruments carry a fixed rate during their respective terms, although the interest rates are reflective of current market conditions, subjecting the companies to fluctuations in interest rates.

Available Short-Term Borrowing Liquidity

The following table outlines available short-term borrowing liquidity as of the dates specified:

	December 31, 2014		December 31, 2013	
	IDACORP[2]	Idaho Power	IDACORP[2]	Idaho Power
Revolving credit facility	$ 125,000	$ 300,000	$ 125,000	$ 300,000
Commercial paper outstanding	(31,300)	—	(54,750)	—
Identified for other use[1]	—	(24,245)	—	(24,245)
Net balance available	$ 93,700	$ 275,755	$ 70,250	$ 275,755

[1] Port of Morrow and American Falls bonds that Idaho Power could be required to purchase prior to maturity under the optional or mandatory purchase provisions of the bonds, if the remarketing agent for the bonds were unable to sell the bonds to third parties.

[2] Holding company only.

At February 13, 2015, IDACORP had no loans outstanding under its credit facility and $24.2 million of commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding. The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2014 and 2013:

	December 31, 2014		December 31, 2013	
	IDACORP[1]	Idaho Power	IDACORP[1]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$ 31,300	$ —	$ 54,750	$ —
Weighted average interest rate	0.43%	—%	0.34%	—%
Daily average amount outstanding during the year	$ 37,786	$ —	$ 61,121	$ 2,209
Weighted average interest rate during the year	0.32%	—%	0.39%	0.43%
Maximum month-end balance	$ 47,300	$ —	$ 67,150	$ 16,600

[1] Holding company only.

Impact of Credit Ratings on Liquidity and Collateral Obligations

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, depends in part on their respective credit ratings. The following table outlines the ratings of Idaho Power's and IDACORP's securities, and the ratings outlook, by Standard & Poor's Ratings Services and Moody's Investors Service as of the date of this report:

	S&P		Moody's	
	IDACORP	Idaho Power	IDACORP	Idaho Power
Corporate Credit Rating/Long-Term Issuer Rating	BBB	BBB	Baa 1	A3
Senior Secured Debt	None	A-	None	A1
Senior Unsecured Debt	None	BBB	None	A3
Short-Term Tax-Exempt Debt	None	BBB/A-2	None	A3/ VMIG-2
Commercial Paper	A-2	A-2	P-2	P-2
Senior Unsecured Credit Facility	None	None	Baa 1	A3
Rating Outlook	Stable	Stable	Stable	Stable

These security ratings reflect the views of the ratings agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2014, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on its unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral, and counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2014, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $8.1 million. To minimize capital requirements, Idaho Power actively monitors its portfolio exposure and the potential exposure to additional requests for performance assurance collateral, through sensitivity analysis.

Capital Requirements

Idaho Power's construction expenditures, excluding AFUDC, were $265 million during the year ended December 31, 2014. The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2015 through 2019 (in millions of dollars). Given the uncertainty associated with the timing of infrastructure projects and associated expenditures, actual expenditures and their timing could deviate substantially from those set forth in the table.

	2015	2016	2017-2019
Ongoing capital expenditures (excluding item listed below in this table)	$ 255-260	$ 285-290	$ 850-905
Jim Bridger plant selective catalytic reduction equipment (discussed below)	45-50	15-20	20-25
Total (excluding AFUDC)	$ 300-310	$ 300-310	$ 870-930

Major Infrastructure Projects: Idaho Power is engaged in the development of a number of significant projects and has entered into arrangements with third parties concerning joint infrastructure development. The most notable projects are described below.

Jim Bridger Plant Selective Catalytic Reduction Equipment and Related IPUC Filing: Idaho Power and the plant co-owners are installing selective catalytic reduction (SCR) equipment to reduce nitrogen oxide (NO_x) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. The regional haze rules provide for installation and operation of SCR on unit 3 by 2015 and unit 4 by 2016. The rules provide for an equivalent technology for NO_x reductions on unit 2 by 2021 and unit 1 by 2022. Idaho Power estimates that the total cost for Idaho Power's share of the upgrades on units 3 and 4 is approximately $113 million, excluding AFUDC. As of December 31, 2014, Idaho Power had expended $46 million, excluding AFUDC, on SCR installation at units 3 and 4.

In June 2013, Idaho Power filed an application with the IPUC requesting that the IPUC issue a Certificate of Public Convenience and Necessity (CPCN) related to the SCR investments planned for units 3 and 4. Idaho Power's CPCN application requested that the IPUC provide Idaho Power with authorization and a binding commitment to provide rate base treatment for Idaho Power's share of the capital investment in the SCR. By filing the CPCN, Idaho Power intended to provide the IPUC with an opportunity to review the prudence of the investment in SCR prior to Idaho Power's incurring the bulk of the associated expenses. In December 2013, the IPUC issued an order granting the CPCN. However, the IPUC declined to grant Idaho Power's additional request for an early determination of binding ratemaking treatment.

Boardman-to-Hemingway Transmission Line: The Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, would provide transmission service to meet future resource needs. The Boardman-to-Hemingway line was included in the preferred resource portfolio in Idaho Power's 2013 IRP. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration (BPA) to pursue permitting of the project. The joint funding agreement provides that Idaho Power's interest in the permitting phase of the project would be approximately 21 percent, and that during future negotiations relating to construction of the transmission line Idaho Power would seek to retain that percentage interest in the completed project. Assuming both other participants fund their full share of the total cost of the permitting phase of the project, Idaho Power's estimated share of the cost of the permitting phase of the project is approximately $35 million, including AFUDC, which has been extended to the project's anticipated in-service date. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including AFUDC. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the permitting phase are not included in the table above.

Idaho Power has expended approximately $64 million on the Boardman-to-Hemingway project through December 31, 2014. Pursuant to the terms of the joint funding arrangements, approximately $32 million of that amount must be reimbursed to Idaho Power by joint permitting participants for expenses Idaho Power incurred, $23 million of which Idaho Power had received as of December 31, 2014. An additional $15 million is subject to reimbursement at a later date from the joint permitting participants, assuming their continued participation in the project, for expenses Idaho Power incurred prior to execution of the joint funding arrangements. Idaho Power plans to seek recovery of its share of project costs through the regulatory process.

The permitting phase of the Boardman-to-Hemingway project is subject to review and approval by the BLM (as the lead federal agency on behalf of other federal agencies), the U.S. Forest Service, and the Oregon Department of Energy. The BLM issued a draft EIS for the project on December 19, 2014, and as of the date of this report Idaho Power expects the BLM to issue a final EIS during 2016. In the separate Oregon state permitting process, Idaho Power submitted a preliminary application for a site certificate in February 2013 and intends to submit an amended preliminary application in late 2015 or in 2016.

The environmental requirements for, and application of environmental regulations (particularly relating to sage grouse) to, the siting process have changed during the project, making permitting for the transmission line more difficult. This has resulted in project delays and increased permitting costs. The completion date of the project is subject to these siting, permitting, and regulatory approval requirements, as well as in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other factors. In light of the delays and siting impediments that have occurred and are expected, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2021 or beyond.

Gateway West Transmission Line: Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. In January 2012, Idaho Power and PacifiCorp entered a new joint funding agreement (Gateway Funding Agreement) for permitting of the project. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $71 million, including AFUDC, which has been extended to the project's anticipated in-service date. Idaho Power has expended approximately $27 million on the permitting phase of the project through December 31, 2014. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $200 million and $400 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs are not included in the table above.

The Gateway Funding Agreement outlines the terms under which the parties will jointly own, develop, design, permit, site, and acquire rights-of-way for the Gateway West transmission project. Idaho Power's interest in the Gateway West project applies to four of 10 segments involved in the project. PacifiCorp is designated as the project manager under the agreement. The Gateway Funding Agreement provides that the project manager may seek to reconfigure portions of the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations. Further, PacifiCorp retains the right to remove specified segments from the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations specified in the Gateway Funding Agreement. Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement. The Gateway Funding Agreement provides for the parties to subsequently negotiate the terms and conditions of one or more definitive development and construction agreements for the Gateway West transmission line.

The permitting phase of the project is subject to review and approval of the BLM. The BLM released its record of decision under the National Environmental Policy Act in November 2013. In its record of decision, the BLM identified its final decision on the routing of the project, issued right-of-way grants on public land for some segments, and deferred a decision on two segments (in both of which Idaho Power has an interest) to resolve routing concerns in those areas. Several interested parties have appealed the BLM's record of decision, and Idaho Power has intervened in the proceedings. The BLM has initiated the supplemental EIS process for the two deferred segments. As of the date of this report, the BLM's schedule provides for the issuance of a record of decision on the two deferred segments by late 2016.

Shoshone Falls Plant Expansion: The Shoshone Falls plant expansion project was included in Idaho Power's 2013 IRP and consists of constructing a new powerhouse, intake structure, penstock, and substation and the installation of a new turbine to increase the nameplate generation capacity of the plant from 12.5 MW to 61.5 MW. The most recent FERC license amendment issued for the plant in 2012 required the project to be completed by 2017. However, as the project is unlikely to be completed by 2017, Idaho Power sought from the FERC an additional schedule extension. In May 2014, the FERC authorized extension of the date of commencement of construction to July 2018 and completion of construction by July 2022. Idaho Power's determination to proceed with the expansion project remains subject to the outcome of additional cost studies and analysis and the results of further engineering and design work, and further analysis of Idaho Power's supply-side resource needs. If Idaho

Power ultimately determines to move forward with the full project, Idaho Power may seek to obtain regulatory support from the IPUC and OPUC prior to commencement of construction to mitigate in part the regulatory cost-recovery risk associated with the project.

Pending Transmission System Transaction: To enhance the abilities of Idaho Power and PacifiCorp to serve their respective customers, on October 24, 2014, Idaho Power and PacifiCorp executed a Joint Ownership and Operating Agreement (Joint Operating Agreement) applicable to certain transmission-related equipment proposed to be exchanged by Idaho Power and PacifiCorp. The proposed exchange would be made pursuant to the terms of a Joint Purchase and Sale Agreement, also dated October 24, 2014, between Idaho Power and PacifiCorp, under which each party agreed to transfer to the other specified transmission-related equipment with an estimated year-end 2014 net book value of approximately $43 million, subject to true-up as of the closing date. The proposed transaction also provides for the termination and amendment of a number of legacy long-term agreements related to the ownership and operation of jointly-owned facilities and transmission services between Idaho Power and PacifiCorp.

The Joint Operating Agreement is intended to provide Idaho Power and PacifiCorp with access to integrated transmission facilities that aligns more closely with current industry standards and allows the parties to more efficiently satisfy regulatory and reliability requirements. The Joint Operating Agreement allocates the directional transmission capacity of the exchanged transmission-related assets between the companies, which will be managed pursuant to each company's OATT. The Joint Operating Agreement also provides for the operation, upgrade, repair, rebuilding, and decommissioning of the exchanged assets and certain other equipment each company owns. Closing of the proposed transaction, effectiveness of the Joint Operating Agreement, and termination and amendment of the legacy long-term transmission service agreements is subject to a number of conditions, including approval by, or notice to, the public utility commissions of California, Idaho, Oregon, Utah, Washington, and Wyoming, and approval by the FERC.

Other Infrastructure Projects: Idaho Power continues to add to its system to accommodate for growth and to reinvest for reliability and general system improvement. These system enhancement projects involve significant capital expenditures. Examples of system enhancements over the period 2015 through 2019, and their estimated costs, include the following:

- $10-$15 million per year for replacement of underground distribution cables;
- $30-$40 million per year for reconstruction of distribution lines;
- $5-$10 million per year for reliability-related construction projects, such as wood pole crossarm replacements and feeder system improvement;
- $50-$90 million per year for transmission-related projects other than the Boardman-to-Hemingway and Gateway West projects;
- $30-$60 million per year for ongoing thermal plant improvement programs other than SCR equipment;
- $10-$20 million per year for hydroelectric plant improvement programs; and
- $20-$30 million per year for general plant improvements, such as information technology, facilities, and fleet vehicles.

Depending on changes in load and project timing Idaho Power may seek to accelerate, scale back, modify, or eliminate projects, or seek alternative projects, to accommodate anticipated resource needs and to help ensure its ability to provide reliable electric service and meet load and transmission capacity obligations. Scaling back or eliminating a project due to regulatory challenges or other factors influencing the feasibility of a project may result in Idaho Power pursuing one or more separate, more costly projects. For instance, if Idaho Power were unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, develop additional generation facilities within areas where Idaho Power has available transmission capacity. Termination of a project carries with it the potential for a write-off of all or a significant portion of the costs associated with the project, largely dependent on decisions of regulators as to the prudence of project expenditures.

Environmental Regulation Costs: Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal plants and for its hydroelectric relicensing efforts. These cost estimates are summarized in Part I - Item 1 - "Business" of this report. The capital portion of these amounts is included in the Capital Requirements table above but do not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

Defined Benefit Pension Plan Contributions and Recovery

Idaho Power contributed $30 million, $30 million, and $44 million to its defined benefit pension plan in 2014, 2013, and 2012, respectively. Idaho Power estimates that it has no minimum contribution requirement for 2015, though it plans to contribute at least $20 million to the pension plan during 2015 in a continued effort to balance the regulatory collection of these expenditures with the cost of being in an underfunded position. In 2016 and beyond, Idaho Power expects significant contribution obligations under the pension plan. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations.

Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2014, Idaho Power's deferral balance associated with the Idaho jurisdiction was $60.9 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. In May 2011, the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. The primary impact of pension contributions is on timing of cash flows, as cost recovery lags behind the timing of contributions.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations for the respective periods in which they are due:

	Payments Due by Period				
	Total	**2015**	**2016-2017**	**2018-2019**	**Thereafter**
	(millions of dollars)				
Long-term debt[1]	$ 1,618	$ 1	$ 2	$ 220	$ 1,395
Future interest payments[2]	1,249	81	161	151	856
Operating leases[3]	18	—	2	2	14
Purchase obligations:					
Cogeneration and small power production	5,143	181	419	479	4,064
Fuel supply agreements	235	64	84	19	68
Purchased power & transmission[4]	21	6	9	2	4
Other[5]	211	74	42	29	66
Pension and postretirement benefit plans[6]	198	8	51	97	42
Other long-term liabilities	1	—	1	—	—
Total	$ 8,694	$ 415	$ 771	$ 999	$ 6,509

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.

(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2014.

(3) The operating leases include right-of-way easements. Approximately $1 million of the obligations included have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(4) Approximately $9 million of the obligations included in purchased power and transmission have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(5) Approximately $122 million of the amounts in other purchase obligations are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes. Other purchase obligations also includes Idaho Power's estimated proportionate funding obligation for goods and services under non-fuel purchase agreements at its jointly owned generation facilities. In some instances, Idaho Power is not a direct party to an underlying purchase agreement, but is obligated under the instruments governing the joint ventures to reimburse the co-owner for payments the co-owner makes pursuant to the purchase agreement. Those estimated amounts have been included in the table above.

(6) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2019 with any level of precision, and amounts through 2019 are estimates only and are subject to change. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP’s common stock are within the discretion of IDACORP’s board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP’s current and long-term financial position and results of operations, capital requirements, rating agency considerations, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power.

IDACORP has a dividend policy that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive IDACORP's board of directors' dividend decisions. Notwithstanding the dividend policy adopted by IDACORP's board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the factors above, among others.

In January 2012, IDACORP's board of directors voted to increase the quarterly dividend from \$0.30 to \$0.33 per share of IDACORP common stock. In September of 2012, 2013, and 2014, IDACORP's board of directors voted to increase the quarterly dividend to \$0.38 per share, \$0.43 per share, and \$0.47 per share of IDACORP common stock, respectively.

For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP’s and Idaho Power’s payment of dividends, see Note 6 – “Common Stock” to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future results of operations and financial condition. Certain legal or administrative proceedings to which IDACORP or Idaho Power are parties or are otherwise involved, and certain actual or potential legal claims pertaining to Idaho Power, are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, in many instances IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of potential new regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

Off-Balance Sheet Arrangements

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was \$70 million at December 31, 2014, representing IERCo's one-third share of BCC's total reclamation obligation of \$209 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2014, the value of the reclamation trust fund totaled \$67 million. During 2014, the reclamation trust fund distributed approximately \$13 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

REGULATORY MATTERS

Introduction

Idaho Power's need for rate relief and the development of rate case plans take into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, among other things, in-service dates of major capital investments, the timing of changes in major revenue and expense items, and customer growth rates. Idaho Power filed general rate cases in Idaho and Oregon during 2011, as well as a single-issue rate case for the Langley Gulch power plant in Idaho and Oregon in 2012. These significant rate cases resulted in the resetting of base rates in both Idaho and Oregon during 2012.

Between general rate cases, Idaho Power relies upon power cost adjustment mechanisms, tariff riders, and other mechanisms to reduce regulatory lag, which refers to the period of time between making an investment or incurring an expense and recovering that investment or expense and earning a return. Management's focus on constructive regulatory outcomes in recent years has been targeted largely at general rate cases, regulatory settlement stipulations, and rate mechanisms. Going forward, Idaho Power will continue to assess its need for general rate relief in consideration of the factors described above. As of the date of this report Idaho Power does not anticipate filing an application for a general rate change in Idaho or Oregon during 2015.

Idaho and Oregon Significant Regulatory Developments

Included in the table below are notable regulatory developments during 2012, 2013, and 2014 that affected Idaho Power's results for the periods. Also refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for a description of the applicable regulatory mechanism and associated orders of the IPUC and OPUC, which should be read in conjunction with the discussion of regulatory matters in this MD&A.

Description	Effective Date	Estimated Annualized Revenue Impact (millions)(1)
Oregon general rate case settlement - 2012 stipulation	3/1/2012	$ 2
2012 Idaho PCA(2)(3)	6/1/2012	16
Idaho - Boardman power plant cost recovery	6/1/2012	1
Idaho depreciation rate for non-AMI meters	6/1/2012	(11)
Idaho depreciation update (other than non-AMI meters and Boardman plant)	6/1/2012	(1)
2012 Idaho FCA(2)	6/1/2012	1
2012 Oregon APCU(2)	6/1/2012	2
Idaho - Langley Gulch power plant	7/1/2012	58
Oregon - Langley Gulch power plant	10/1/2012	3
2013 Idaho FCA(2)	6/1/2013	(1)
2013 Idaho PCA(2)(4)	6/1/2013	140
2013 Oregon APCU(2)	6/1/2013	3
2014 Idaho FCA(2)	6/1/2014	6
2014 Idaho PCA(2)(5)	6/1/2014	(88)
Transfer of power supply costs from the Idaho PCA mechanism to Idaho base rates(6)	6/1/2014	99

(1) The annual amount collected in rates is typically not recovered on a linear basis (i.e., 1/12th per month), and is instead recovered in proportion to general business sales volumes.

(2) The rate changes for the Idaho PCA and FCA are applicable only for one-year periods. Similarly, a portion of the rate changes from the Oregon APCU are applicable only for one-year periods.

(3) 2012 PCA rates reflect $27 million of Idaho customer revenue sharing related to 2011 financial results pursuant to an Idaho regulatory settlement stipulation, resulting in a net rate increase of $16 million.

(4) 2013 PCA rates reflect $7 million of Idaho revenue-sharing related to 2012 financial results pursuant to an IPUC order issued in 2013 under regulatory settlement agreements approved in January 2010 and December 2011. The $140 million increase in PCA rates includes the reduction in the PCA mechanism component of the revenue sharing amount from $27 million for the 2012 PCA to $7 million for the 2013 PCA.

(5) 2014 PCA rates reflect (a) the application of $20 million of surplus Idaho energy efficiency rider funds, (b) $8 million of customer revenue sharing for the year 2013 under a regulatory settlement agreement approved in December 2011, and (c) a $99 million shift in base net power supply expenses from recovery via the PCA mechanism to recovery through base rates.

(6) See footnote 5 above. Approval of the transfer of collection of specified power supply costs from the Idaho PCA mechanism to Idaho base rates resulted in no net change in customer rates.

Resetting of Idaho Base Rates: In December 2011, the IPUC approved a settlement stipulation in Idaho Power's Idaho general rate case, which provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. New rates in conformity with the settlement became effective on January 1, 2012. On June 29, 2012, the IPUC issued an order approving a $58.1 million, or 6.83 percent, increase in annual Idaho-jurisdiction base rates, effective July 1, 2012, for recovery of Idaho Power's investment in the Langley Gulch power plant and associated costs. Neither of the IPUC's general rate change orders nor the December 2011 settlement stipulation specified an authorized rate of return on equity.

Since 2010, when Idaho Power's normalized level of net power supply expenses included in Idaho base rates last received a comprehensive review, many of the individual cost and revenue components of these "base level" net power supply expenses, which were being recovered through the Idaho PCA, changed significantly and permanently. The primary components that contributed to the increase in net power supply expenses are increased energy purchases pursuant to PURPA power purchase agreements, lower surplus energy sales revenue resulting from lower energy market prices, and the elimination of anticipated offsetting revenues from one special contract customer. In light of these permanent increases, on November 1, 2013, Idaho Power filed an application with the IPUC requesting an increase of approximately $106 million on a total-system basis in the normalized or “base level” power supply expense to be used to update base rates and in the determination of the PCA rate that would become effective June 1, 2014. On March 21, 2014, the IPUC issued an order approving Idaho Power's application. This removed the Idaho-jurisdiction portion of those expenses ($99 million) from collection via the Idaho PCA mechanism and instead results in Idaho Power collecting that portion in base rates. Approval of the application resulted in no change in the aggregate amount collected through base rates and the PCA mechanism. However, the approved application will reduce the magnitude of any base rate increase requested by Idaho Power in its next general rate case application filed with the IPUC.

Resetting of Oregon Base Rates: On February 23, 2012, the OPUC approved a settlement stipulation in Idaho Power's Oregon general rate case providing for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation went into effect on March 1, 2012. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

Idaho Regulatory Settlement Stipulations: In December 2011, the IPUC issued an order, separate from the then-pending Idaho general rate case proceeding, approving a settlement stipulation that allowed Idaho Power to, in certain circumstances, amortize additional ADITC if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 was less than 9.5 percent, to help achieve a 9.5 percent Idaho ROE for the applicable year. When Idaho Power's actual Idaho ROE for any of those years exceeded 10.0 percent, Idaho Power was required to share a portion of its Idaho-jurisdiction earnings with Idaho customers. As Idaho Power's 2012, 2013, and 2014 Idaho ROE exceeded 10.0 percent, Idaho Power did not amortize additional ADITC for those years, but instead shared earnings with customers. The amounts Idaho Power recorded for sharing for those years were as follows (in millions of dollars):

	2014	2013	2012
Additional pension expense funded through sharing	$ 16.7	$ 16.5	$ 14.6
Provision against current revenue as a result of sharing	8.0	7.6	7.2
Total	$ 24.7	$ 24.1	$ 21.8

In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The more specific terms and conditions of the December 2011 and October 2014 Idaho settlement stipulations are described in Note 3 - "Regulatory Matters - *Idaho Regulatory Matters*" to the consolidated financial statements included in this report. IDACORP and Idaho Power believe that the terms allowing amortization of additional ADITC in the October 2014 settlement stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect.

IPUC Review of Annual Rate Adjustment Mechanisms: On July 1, 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties would further evaluate Idaho Power's application of the true-up component of the PCA mechanism and whether a deferral balance adjustment is appropriate. The docket arose from the IPUC's May 2014 PCA order, which noted that the IPUC Staff believed that Idaho Power's application of the true-up component introduces a line-loss bias that inflated the true-up revenue it must collect by $14.2 million. The IPUC's docket was closed via an order issued by the IPUC on August 6, 2014, with no change to the PCA mechanism. Idaho Power has subsequently met with interested parties to explore approaches to increasing the accuracy of the actual cost recovery under the PCA mechanism, and discussions are ongoing.

Also on July 1, 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA. The FCA is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual (weather-normalized) fixed costs recovered by Idaho Power during the year. Concerns cited by interested parties included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. Proceedings in the FCA docket, which remains open, could result in significant changes to the FCA.

Deferred (Accrued) Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual forecasts of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. Idaho Power's PCA mechanisms in its Idaho and Oregon jurisdictions provide for annual adjustments to the rates charged to retail customers. The PCA mechanism and associated financial impacts are described in "Results of Operations" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Factors that have influenced significant PCA rate changes in recent years include year-to-year volatility in hydroelectric generation conditions, market energy prices and the volume of off-system sales, power purchase costs from renewable energy projects, and revenue sharing under Idaho regulatory settlement stipulations. From year to year, the factors that influence power supply costs can vary significantly, which can result in significant accruals and deferrals under the PCA mechanism. For example, in May 2012 the IPUC issued an order approving a PCA rate increase of $15.9 million, after application of the revenue sharing amount required by the December 2011 Idaho regulatory settlement stipulation. By comparison, in May 2013 the IPUC issued an order authorizing a $140.4 million increase in PCA rates.

As noted above under "*Resetting of Idaho Base Rates*," in light of the existence of permanent increases in power supply costs, in March 2014 the IPUC issued an order approving Idaho Power's application requesting recovery of a portion of its ongoing power supply costs through base rates rather than through the Idaho PCA mechanism.

The table that follows summarizes the change in deferred net power supply costs over the prior two years:

	Idaho	Oregon[(1)]	Total
Balance at December 31, 2012	$ 34,571	$ 8,331	$ 42,902
Current period net power supply costs deferred	67,127	—	67,127
Revenue sharing liability applied to PCA true-up mechanism	(7,172)	—	(7,172)
Prior deferred costs amortized and recovered through rates	(9,728)	(2,224)	(11,952)
SO_2 allowance and renewable energy certificate (REC) sales	(522)	(15)	(537)
Interest and other	567	519	1,086
Balance at December 31, 2013	84,843	6,611	91,454
Current period net power supply costs deferred	48,104	—	48,104
Revenue sharing and energy efficiency rider funds	(27,624)	—	(27,624)
Prior deferred costs amortized and recovered through rates	(48,489)	(2,210)	(50,699)
SO_2 allowance and renewable energy certificate (REC) sales	(2,895)	(127)	(3,022)
Interest and other	573	403	976
Balance at December 31, 2014	$ 54,512	$ 4,677	$ 59,189

(1) Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $3 million). Deferrals are amortized sequentially.

Relicensing of Hydroelectric Projects

Overview: Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses have a term of 30 to 50 years depending on the size, complexity, and cost of the project. The expiration dates for the FERC licenses for each of the facilities are included in Part I - Item 2 - "Properties" in this report. Costs for the relicensing of Idaho Power's hydroelectric projects are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $199 million for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2014. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.7 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. As of December 31, 2014, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $73 million. In addition to the discussion below, see "Environmental Matters" in this MD&A for a discussion of environmental compliance under FERC licenses for Idaho Power's hydroelectric generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application with the FERC for a new license in anticipation of the July 2005 expiration of the then-existing license. Since the expiration of that license, Idaho Power has been operating the project under annual licenses issued by the FERC. In December 2004, Idaho Power and eleven other parties, including National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS), involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on Endangered Species Act (ESA) listed species pending the relicensing of the project. In August 2007 the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act (CWA) and formal consultations under the ESA, which remain unresolved.

In connection with its relicensing efforts, Idaho Power has filed water quality certification applications, required under Section 401 of the CWA, with the states of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Section 401 of the CWA requires that a state either approve or deny a Section 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its Section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

In September 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species, including the bull trout and fall Chinook salmon and steelhead, under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed.

Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns. Idaho Power has begun the process for construction of new aerated runners at the Brownlee project (part of the HCC) at an estimated cost of $50 million. Other measures that have been proposed or considered have included modification of spillways at Brownlee and Hells Canyon to address total dissolved gas issues, and upstream watershed improvements or the installation of a temperature control structure to address water temperatures during a small portion of the year. If Idaho Power is required to take these or other additional measures to satisfy relicensing requirements, it could add substantially to project costs. Idaho Power continues to work with the Oregon and Idaho Departments of Environmental Quality on the water quality certification issue and the water quality measures that will be required to obtain 401 certification. As of the date of this report, Idaho Power is unable to predict the timing of issuance by the FERC of any license order or the ultimate capital investment and ongoing operating and maintenance costs Idaho Power will incur in complying with any new license.

Renewable Energy Standards and Contracts

Renewable Portfolio Standards: Numerous proponents have introduced legislation in the U.S. Congress that would require electric utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal or State of Idaho RPS is in effect. Idaho Power will be required to comply with a 10-percent RPS in Oregon beginning in 2025, and Idaho Power expects to meet this requirement with RECs obtained from the purchase of power from the Elkhorn Valley wind project. Idaho Power continues to monitor proposed federal RPS legislation and the possibility of additional state RPS legislation.

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2014 and 2013, Idaho Power's REC sales totaled $3.2 million and $0.6 million, respectively. The comparative increase in REC sales resulted primarily from the execution of new REC purchase and sale agreements with third parties for sales during 2014. Idaho Power has sold all of its 2013 and earlier vintage RECs. Idaho Power has sold a portion of its 2014 RECs and intends to continue selling its 2014 and later RECs as they are generated and become available for sale.

Were Idaho Power to be subject to additional RPS legislation, it may cease in full or in part the sale of RECs it receives, seek to obtain RECs from additional projects, generate RECs from any REC-generating facilities it owns or may be required to construct in light of an RPS, or purchase RECs in the market. Historically, Idaho Power has generally not received the RECs associated with PURPA projects. However, an order issued by the IPUC in December 2012, described below, provides that Idaho Power will own a portion of the RECs generated by some PURPA projects. The required purchase of additional RECs to meet RPS requirements would increase Idaho Power's costs, which Idaho Power expects would be wholly or largely passed on to customers through rates and the PCA mechanisms.

Renewable Energy Contracts and PURPA: Idaho Power purchases wind power from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project -- the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of December 31, 2014, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW and an additional 50 MW of CSPP wind power projects not on-line and scheduled to come on-line by year-end 2016. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of power from other CSPP and non-CSPP renewable generation sources, such as biomass, solar, small hydroelectric projects, and two geothermal projects. Recently, Idaho Power has received numerous requests for proposed power purchase contracts from developers of a number of potential solar power projects. As of December 31, 2014, Idaho Power had contracts to purchase energy from solar projects not yet on-line for a total of 461 MW. All of these solar projects have estimated on-line dates no later than year-end 2016. The following tables sets forth, as of December 31, 2014, the number and nameplate capacity of Idaho Power's signed CSPP-related agreements. These agreements have original contract terms ranging from one to 35 years.

Status	Number of CSPP Contracts	Nameplate Capacity (MW)
On-line as of December 31, 2014	105	781
Contracted and projected to come on-line by June 1, 2017	28	521

Pursuant to the requirements of Section 210 of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from CSPP facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements can result in Idaho Power acquiring energy that it does not need to serve customer loads at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. As the volume of CSPP purchases increases under PURPA, the magnitude of the costs and integration issues also increases. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms, and thus the primary impact of PURPA agreements is on customer rates.

Idaho Power has been involved in a number of PURPA-related proceedings at the IPUC, OPUC, and the FERC, and has previously intervened in proceedings between the IPUC and the FERC. In June 2011, the IPUC issued an order providing for a 100 kW eligibility cap for published avoided cost rates for wind and solar PURPA projects. In December 2012, the IPUC issued an order providing that for projects not eligible for published avoided cost rates, the price used for power purchase determinations would be updated annually based on updated natural gas prices and Idaho Power's updated load forecast. The IPUC also determined that RECs will be owned by the PURPA project developer for projects eligible for published avoided cost rates, and apportioned equally between the project developer and Idaho Power for other projects. The IPUC's order also provided that new projects will be paid for capacity based on the project's ability to deliver during peak hours and when Idaho Power's long-range plan shows the company is capacity deficient. Additionally, in December 2013 the IPUC and the FERC signed a memorandum of agreement dismissing claims brought in a U.S. District Court in Idaho relating to the interpretation and enforcement of PURPA as it pertained to several power purchase agreements with wind power developers.

Most recently, in light of the volume of intermittent generation Idaho Power is required to purchase pursuant to existing PURPA power purchase agreements and the substantial increase in volume of proposed new solar generation facilities seeking power purchase agreements with Idaho Power, on January 30, 2015, Idaho Power filed an application with the IPUC requesting that the IPUC issue an order directing that the maximum required term for prospective PURPA power purchase agreements be reduced from 20 years to two years. In its application, Idaho Power stated that the requested modification to terms of PURPA energy purchases is necessary to prevent harm to Idaho Power's customers that may result from entering into additional long-term, fixed-rate purchase agreements when Idaho Power predicts that there is no need for new generation capacity through 2021. On February 6, 2015, the IPUC issued an order reducing the maximum contract term of future PURPA power purchase agreements from 20 years to five years during the pendency of the proceedings.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the environment, including the Clean Air Act (CAA), the Clean Water Act, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the ESA, among other laws. Current and pending environmental legislation relates to, among other issues, climate change, greenhouse gas, mercury and other emissions, air quality, hazardous wastes, polychlorinated biphenyls (PCBs), and threatened and endangered species. These laws are administered by a number of federal, state, and local agencies. In addition to imposing continuing compliance obligations and associated costs, these laws and regulations provide authority to regulators to levy substantial penalties for noncompliance, injunctive relief, and other sanctions. Idaho Power's three co-owned coal-fired power plants and three natural gas-fired combustion turbine power plants are subject to many of these regulations. Idaho Power's 17 hydroelectric projects are also further subject to a number of water discharge standards and other environmental requirements.

Compliance with current and future environmental laws and regulations may:

- increase the operating costs of generating plants;
- increase the construction costs and lead time for new facilities;
- require the modification of existing generating plants, which could result in additional costs;
- require the curtailment or shut-down of existing generating plants; or
- reduce the output from current generating facilities.

Current and future environmental laws and regulations will increase the cost of operating coal-fired power plants and constructing new facilities, in large part as a result of the installation of additional pollution control devices at existing generating plants. The cost of additional pollution control equipment could cause Idaho Power to discontinue the operation of one or more coal-fired plants, where those costs are substantial and cause operation of the plant to become uneconomical. In connection with its IRP process, Idaho Power has conducted cost studies and scenario analysis to assess the potential future investments necessary for the continued operation of the Jim Bridger and North Valmy coal generation facilities, in light of the environmental laws and regulations impacting the costs of operating those plants. The results of that study are discussed in Part I, Item 1 - "Business - Utility Operations - *Environmental Regulation and Costs*."

In addition to increasing costs generally, these environmental laws and regulations could affect IDACORP's and Idaho Power's results of operations and financial condition if the costs associated with these environmental requirements and early plant retirements cannot be fully recovered in rates on a timely basis. Part I, Item 1 - “Business - Utility Operations - *Environmental*

Regulation and Costs" in this report includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2015 to 2017. Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2017, though they could be substantial.

Endangered Species and Fisheries Matters

Overview: The listing of a species of fish, wildlife, or plants as threatened or endangered under the ESA may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or relicense or operate its hydroelectric facilities. When a species is added to the federal list of threatened and endangered species, it is protected from "take," which is defined to include harming the species. The ESA directs that, concurrent with a designation of a threatened or endangered species, and where prudent and determinable, the applicable agency also designate "any habitat of such species which is then considered to be critical habitat." The ESA also provides that each federal agency shall ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of its critical habitat. If an action is determined to result in adverse modification of critical habitat, the federal action agency must adopt changes to the proposed action to avoid such adverse modification. These changes are often quite extensive and can affect the size, scope and even the feasibility of a project moving forward. In May 2014, the USFWS and the NMFS proposed a set of regulatory changes and policies relating to critical habitat and adverse modification determinations. Taken as a whole, Idaho Power believes that the proposed changes could result in the applicable agencies having greater authority in making broad-scale designations of critical habitat and could increase the likelihood of adverse modification determinations.

The construction of generation, transmission, or distribution facilities and the relicensing of Idaho Power's hydroelectric projects can be federally authorized actions that fall under the ESA. There are a number of threatened or endangered species within Idaho Power's service area and within or near proposed transmission line routes. Further, there are a number of ESA-listed fish and other aquatic species located in waterways in which Idaho Power has hydroelectric facilities, including fall Chinook salmon, bull trout, Bliss Rapids snail, and Snake River physa snail. To date, efforts to protect these and other listed species have not significantly affected generation levels or operating costs at any of Idaho Power's hydroelectric facilities. However, the ongoing relicensing of the HCC presents endangered species and fisheries issues that may require generation or other operational adjustments. These adjustments may reduce the generation output or capital or operating costs of the plants, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

ESA Issues Related to Specific Species:

Slickspot Peppergrass: This southwestern Idaho plant species was listed as threatened by the USFWS in 2009. In May 2011, the USFWS issued a proposed rule to designate critical habitat for the slickspot peppergrass and proposed to designate approximately 58,000 acres of critical habitat in four southeast Idaho counties. Most of the species is located on federal land owned by the BLM and the U.S. Department of Defense. The BLM is currently treating the species as a proposed species under the ESA and will confer with the USFWS until a final decision is made. Parts of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines will cross BLM land upon which this species is located. The listing of the slickspot peppergrass would require that Idaho Power, as one of the project developers, engage in an ESA Section 7 consultation with the USFWS, which would increase the cost of the transmission projects and potentially delay the receipt of a permit for construction.

Greater Sage Grouse: The greater sage grouse is considered a "candidate species" under the ESA, which allows land management agencies to implement additional conservation measures. In March 2010, the USFWS announced that listing of the greater sage grouse as threatened or endangered under the ESA is warranted but precluded by higher priority listing actions. In February 2012, a federal district court in Idaho denied a request to expedite the listing of the greater sage grouse under the ESA. As a result, the USFWS has until September 30, 2015 to make a final listing determination under the ESA. Also in February 2012, the same court issued an order holding that the BLM had violated the National Environmental Policy Act and other federal laws in connection with the granting of livestock grazing permit renewals in sage grouse habitat. Due to the presence of sage grouse in the vicinity of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines, siting of these projects has required more extensive, costly, and time consuming evaluation, permitting, and engineering. In the event the USFWS lists the greater sage grouse as threatened or endangered, federal agencies that may authorize rights-of-way to Idaho Power, as one of the project developers, would be required to conduct a Section 7 consultation under the ESA for these transmission projects. Any required additional conservation measures may impact the timing and feasibility of siting, permitting, and constructing the Boardman-to-Hemingway and Gateway West transmission lines and other projects.

Washington Ground Squirrel: The Washington ground squirrel is considered a "candidate species" under the ESA. There are multiple records of Washington ground squirrels within or near portions of the proposed Boardman-to-Hemingway transmission line project. If this species is listed under the ESA, the BLM would be required to conduct a Section 7 consultation under the ESA for the Boardman-to-Hemingway project. If additional surveys are required, or if additional conservation and mitigation measures need to be developed, the overall timing of the permitting and construction, and the cost, of the Boardman-to-Hemingway project may be adversely affected.

ESA Issues Related to Specific Projects:

Hells Canyon Relicensing Project: In 2007, the FERC requested initiation of formal consultation under the ESA with the NMFS and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has yet to be initiated and the NMFS and the USFWS continue to gather and consider information relative to the effects of relicensing on relevant ESA listed species. Idaho Power continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns. In December 2004, Idaho Power and eleven other parties, including NMFS and the USFWS, entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. At the conclusion of formal consultation and with the issuance of biological opinions by the NMFS and the USFWS and an operating license by the FERC, Idaho Power may be required to implement additional measures or further modify or adjust operations to comply with Section 7 of the ESA. The issuance of a final biological opinion during 2015 is unlikely.

Boardman-to-Hemingway and Gateway West Transmission Projects: As noted above, the existence of the slickspot peppergrass, greater sage grouse, and Washington ground squirrel within or near the proposed routes for these projects is impacting, and Idaho Power expects it to continue to impact, the cost and timing of permitting and construction of the projects.

Climate Change and the Regulation of Greenhouse Gas (GHG) Emissions

Overview: Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand and energy loads;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of those and other commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources; and
- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Federal and state regulations pertaining to GHG emissions under the CAA, including a proposed rule issued by the U.S. Environmental Protection Agency (EPA) under Section 111(d) of the CAA, could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Stringent emissions standards could result in significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units and create power system reliability issues. Due in part to the uncertainty of future GHG regulations, in its 2011 and 2013 IRPs Idaho Power did not include any new conventional coal resources in its resource portfolios. While it is not yet possible to determine the requirements of the final rule, in its 2015 IRP Idaho Power expects to include planning scenarios that take into account potential provisions of Rule 111(d) under the CAA.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National GHG Initiatives; Proposed Rule Under CAA Section 111(d): There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. The EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in the enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of "best available control technology" for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the GHG Tailoring Rule.

On June 2, 2014, the EPA released, under Section 111(d) of the CAA, a proposed rule for addressing GHG emissions from existing fossil fuel-fired electric generating units (EGUs). According to the EPA, the rule is designed to achieve a 30 percent reduction in CO_2 emissions from the power sector. The proposal has two main elements: (1) state-specific emission rate-based CO_2 goals and (2) guidelines for the development, submission, and implementation of state plans. The EPA used 2012 as the baseline when calculating the state-specific emission rate goals. While the proposal lays out state-specific CO_2 goals that each state is required to meet, it does not prescribe how a state should meet its goal. Under the proposal, each state may seek to do so alone or may seek to collaborate with other states on multi-state plans.

Under the proposed rule, the EPA would permit states to develop plans to reduce CO_2 emissions under an approach referred to as the "best system of emission reduction." This approach is intended to take into account both the cost and technical feasibility of achieving such reduction. States would have flexibility to implement measures that, in some cases, are already in progress. The EPA has grouped these measures into the following four "building blocks," which generally describe four approaches for CO_2 emission reduction:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs.
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA's proposal requires that states meet their goal by 2030, with periodic reports to the EPA starting in 2022. The proposal also provides for states meeting interim goals from 2020 to 2029. The EPA has stated that it expects to finalize the rulemaking by mid-summer 2015. State implementation plans would be due by June 30, 2016, subject to extension for portions of the plan to June 30, 2017 for state plans or June 30, 2018 for multi-state plans, under certain circumstances.

Idaho Power has analyzed the proposed rule and is participating in state, regional, and national forums that are seeking to address the potential financial and operational impacts of the proposal and identify the means by which states may seek to achieve compliance. Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, as of the date of this report Idaho Power is unable to determine the financial or operational impacts of the proposed rule, if it were to be adopted as proposed.

State and Regional GHG Initiatives: On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The Boardman coal-fired power plant located in Oregon, in which Idaho

Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements and is scheduled to cease coal-fired operations in 2020.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel generating plants (i.e. Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

Idaho Power's Voluntary GHG Reduction Initiatives: Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emissions intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Information on Idaho Power's emission intensity is included in Part I, Item 1 - "Business - *Environmental Regulation and Costs*" in this report. In 2013, Idaho Power and Ida-West together ranked as the 38^{th} lowest emitter of CO_2 per MWh produced and the 36^{th} lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to the May 2014 Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, based on 2012 generation and emissions data. This report is the product of a collaborative effort among Ceres, Bank of America, four power producers, and the Natural Resources Defense Council.

Public Nuisance-Related Suits for GHGs: In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to the federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court's decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

Clean Air Act Matters

Overview: In addition to the CAA developments related to GHG emissions described above, several other regulatory programs developed under the CAA impact Idaho Power. These include the final Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards (NAAQS), NSR/PSD Rules, and the Regional Haze Rule.

Final MATS Implementation: Several regulatory programs developed under the CAA impact Idaho Power. The CAA requires the EPA to develop industry-based standards to control emissions of hazardous air pollutants (HAPs). In February 2012, the EPA issued the final MATS rule to control emissions of mercury and other HAPs from coal- and oil-fired EGUs under the CAA. Additionally, in March 2013, the EPA issued a notice by which it finalized its MATS with regard to all pending issues except for the shutdown and startup of plants, in light of a number of requests for reconsideration that were filed by the electric utility industry. The notice revised the mercury emissions standard originally proposed in the February 2012 rule to make the mercury emission standard less stringent. The final rule took effect in April 2013. The compliance deadline for the new MATS has been established as April 2015. While the new MATS only applies to EGUs constructed in the future, and as a result Idaho Power does not expect the new standards to impact its existing generation facilities, the new MATS would impact the nature and extent of environmental controls to be installed on new EGUs, and thus would likely increase the cost of constructing new EGUs.

National Ambient Air Quality Standards: The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. These six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans, or SIPs, based on attainment of these ambient air quality standards. Recent developments related to certain of those items relevant to Idaho Power include the following:

- *Particular Matter ($PM_{2.5}$)*. In 1997, the EPA adopted NAAQS for fine particulate matter of less than 2.5 micrometers in diameter ($PM_{2.5}$ standard), setting an annual limit of 15 micrograms per cubic meter ($\mu g/m^3$), calculated as a three-year average. In 2006, the EPA adopted a 24-hour NAAQS for $PM_{2.5}$. of 35 $\mu g/m^3$. All of the counties in Idaho, Nevada, Oregon, and Wyoming in which Idaho Power's power plants are located have been designated as "attainment" with these $PM_{2.5}$ standards. However, in December 2012, the EPA released final revisions to the $PM_{2.5}$ NAAQS. The revised annual standard is 12 $\mu g/m^3$, calculated as a three-year average. The EPA retained the existing 24-hour standard of 35 $\mu g/m^3$. On December 18, 2014, the EPA issued final area designations for the 2012 $PM_{2.5}$ NAAQS, with the states of Wyoming, Nevada, and Oregon and all Idaho counties within Idaho Power's service area receiving attainment designations.

- $\underline{NO_x}$. In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a 1-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power owns or has an interest in a natural gas or coal-fired power plant as “unclassifiable/attainment” for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants. As the designations have not yet been finalized, as of the date of this report Idaho Power is unable to predict the impact of the NAAQS for NO_x on its operations. However, the costs of installation and implementation of any additional pollution reduction technology could be substantial.

- $\underline{SO_2}$. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Idaho, Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data. In February 2013, the EPA issued letters to the states of Idaho and Oregon, finding that the most recent air quality data for those states showed no violations of the 2010 SO_2 standard. As a result, the EPA is waiting to propose designation actions for those states, and is likely to proceed with designation actions once additional data is gathered. Idaho Power expects that designations for Nevada and Wyoming will also be addressed in a separate future action.

- *Ozone*. In late 2014, the EPA issued a proposed rule that would update the ozone standard under the CAA, from 75 parts per billion over an eight-hour period to 65 to 70 parts per billion over an eight-hour period. Under the proposed rule, the EPA would make attainment and non-attainment designations for any revised standards by October 2017, with states having until 2020 to late 2037 to meet the proposed standard, with attainment dates varying based on the ozone level in the area. The designation of an area as non-attainment, and SIPs implemented in order to reach attainment, could make the construction of new power generation plants, and operation of existing generation plants, more difficult or costly.

Because the EPA has not yet completed the designation of areas as attaining or not attaining the NAAQS for NO_x, SO_2, and ozone, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations, though it does expect at least some increases in capital and operating costs from the standards.

Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any "Class I" (wilderness) areas. This includes all four units at the Jim Bridger and the Boardman coal-fired plants.

Jim Bridger Plant: In December 2009, the Wyoming Department of Environmental Quality (WDEQ) issued a RH BART permit to PacifiCorp as the operator of the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install SCR equipment for NO_x control at Jim Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by December 31, 2017 to install add-on NO_x controls at Jim Bridger unit 2 by 2021 and unit 1 by 2022. In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp agreed to the timing and nature of the controls. The settlement agreement was conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze SIP that are consistent with the terms of the settlement agreement. On January 10, 2014, the EPA approved Wyoming's Regional Haze SIP as to the Jim Bridger plant, with the NO_x control compliance dates set forth in the settlement agreement. Several interested parties have appealed the EPA's decisions on Wyoming's RH SIP on various grounds. Idaho Power has not appealed the EPA's decisions but has intervened in the proceedings to participate if and to the extent the Jim Bridger plant could be affected.

Boardman Plant: Following the introduction of various plans and an extensive public process, in December 2010 the Oregon Environmental Quality Commission (OEQC) approved a plan to cease coal-fired operations at the Boardman power plant no later than December 31, 2020. The rules implementing the plan require the installation of a number of emissions controls and repeal the OEQC's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more extensive suite of emissions controls. Idaho Power's share of the capital cost of the required controls under the plan approved by the OEQC for controlling mercury, NO_x, and SO_2 was approximately $6 million.

New Source Review / Prevention of Significant Deterioration: NSR/PSD is a pre-construction permitting program that requires a stationary source of air pollution to obtain a permit before beginning construction. The purpose of the program is to ensure that air quality is not significantly degraded by the addition of new and modified facilities, industrial boilers, and power plants. Under current NSR provisions of the CAA, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory equivalent before beginning the construction of a stationary source that will emit regulated pollutants, or before modifying an existing stationary source that will increase its emission levels. Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS under the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. As part of an industry-wide assessment of compliance with NSR and NSPS, EPA has sought information from a number of utilities regarding their coal-fired generating facilities. In 2003, the EPA sent information requests pursuant to the CAA to the Jim Bridger plant, seeking information relevant to NSR and NSPS compliance. Additional requests were received by the Boardman plant in 2008, with a follow up request for information in 2009 and by the Valmy plant in 2009. In September 2010, the EPA issued a Notice of Violation to Portland General Electric Company, the operator of the Boardman plant, alleging that Portland General Electric Company violated the NSPS under Section 111 of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. To date, the EPA has not taken action on the Notice of Violation, and a related private lawsuit under the CAA was settled in 2011.

Regulation of Coal Combustion Residuals (CCRs)

The Resource Conservation and Recovery Act (RCRA) is a federal statute regulating the generation, treatment, storage, and disposal of solid and hazardous wastes. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties. In response, in June 2010 the EPA proposed regulations governing the disposal and management of CCRs, which are regulated under the RCRA. In December 2014, the EPA signed a final rule for the disposal of CCRs. The rule establishes structural integrity design criteria and requires that owners and operators periodically conduct a number of structural integrity related assessments and install monitoring apparatus. The final rule also imposes location restrictions on impoundments, requires the closure of impoundments that cannot meet the location restrictions, imposes liner design criteria and operating requirements, and imposes certain record keeping and notification requirements. Additionally, the EPA's rule imposes obligations associated with the closure of CCR impoundments. As of the date of this report, Idaho Power and its co-owners of coal-fired units are performing engineering and cost studies to determine the financial and operational impact of the rule. The rule becomes effective in 2015. Upon completion of engineering and cost studies, Idaho Power plans to incorporate any impact of this rule into its estimates of asset retirement obligations associated with coal ash disposal facilities at its coal plants.

Regulation of Polychlorinated Biphenyls

The Toxic Substances Control Act is a federal statute providing the EPA with the authority to, among other things, require use restrictions relating to chemical substances including PCBs. Generally, PCBs are prohibited from use, but some uses of PCBs - such as in electrical equipment - remain authorized under certain conditions. In April 2010, the EPA issued an advance notice of proposed rulemaking stating that it is considering revisiting the authorization allowing the continued use of PCBs in equipment. If new regulations require the replacement of existing equipment, they could have an adverse effect on IDACORP's and Idaho Power's financial condition and results of operations. However, the financial and operational consequences cannot be determined until final regulations are issued. Idaho Power currently records asset retirement obligation liabilities and associated regulatory assets for the estimated retirement costs of equipment containing PCBs. Final regulations could accelerate Idaho Power's estimated timing for the retirement of equipment with PCBs.

Clean Water Act Matters

Potential Expansion of CWA Scope: On April 21, 2014, the EPA and U.S. Army Corps of Engineers jointly published for public comment a proposed rule to revise the definition of "waters of the United States" for purposes of the CWA. The proposed rule would potentially expand federal jurisdiction under the CWA beyond traditional navigable waters, interstate waters, territorial seas, tributaries, and adjacent wetlands, to a number of other waters, including waters with a "significant nexus" to those traditional waters. The rule could trigger substantial additional permitting and regulatory requirements under multiple provisions of the CWA. Idaho Power is analyzing the proposed rule but as of the date of this report is unable to determine the impact of the proposed rule, should it become final, on its operations.

Potential Section 316(b) Regulation of Cooling Water Intake Structures: The CWA generally prohibits the discharge of any "pollutant" from a point source into waters of the United States without a permit. Pollutants are broadly defined to include changes in temperature. Section 316(b) of the CWA requires that National Pollutant Discharge Elimination System permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures employ the best technology available (BTA) to minimize harmful impacts on the environment, such as the removal of fish, fish larvae, marine mammals, and other aquatic organisms from waters of the U.S. In May 2014, the EPA issued final rules that establish requirements under Section 316(b) of the CWA for existing power generation facilities that withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. These facilities are required to reduce fish impingement under the final rules, using one of several options for meeting BTA requirements for reducing impingement. Based on the qualification criteria, Idaho Power is evaluating whether these new requirements apply to the Jim Bridger plant. Idaho Power and the plant's co-owner are performing studies at the plant to determine the applicability of the new rules and the infrastructure improvements or operational changes that may be required for the plant to comply with the new rules, if applicable. Based on its preliminary analysis, as of the date of this report Idaho Power does not expect that compliance with the new rules will result in a material increase in costs.

Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See “Relicensing of Hydroelectric Projects” in this MD&A for additional information on the impact of the CWA on that relicensing effort.

Effluent Limitation Guidelines and Standards: In June 2013, the EPA issued proposed rulemaking to revise the technology-based effluent limitation guidelines and standards under the CWA for water discharged from steam electric power plants, which includes coal-fired plants. The proposed rule would establish new or additional requirements for wastewater streams from a number of processes associated with steam electric power generation. The EPA has stated that more than half of coal-fired plants in the United States would be in compliance with the proposed rules without incurring any additional cost, and stated that its cost analysis shows very small effects on the electric power market. Idaho Power has conducted a preliminary analysis based on the proposed rule and as of the date of this report does not anticipate that the proposed rule would materially affect Idaho Power’s operations or financial condition, but the company expects to conduct an additional assessment when and if final rules are issued.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with generally accepted accounting principles (GAAP), IDACORP’s and Idaho Power’s management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management’s control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates. Management believes the accounting policies and estimates discussed below are the most critical to the portrayal of their financial condition and results of operations and require management’s most difficult, subjective, or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power had recorded $1.2 billion of regulatory assets and $402 million of regulatory liabilities at December 31, 2014. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Either circumstance could have a material effect on Idaho Power’s financial condition or results of operations.

Income Taxes

IDACORP and Idaho Power use judgment and estimation in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes for other items are provided for the temporary differences between the income tax and financial accounting treatment of such items. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax temporary differences where the prescribed regulatory accounting methods, or flow-through, direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

Refer to Note 1 - “Summary of Significant Accounting Policies” and Note 2 - “Income Taxes” to the consolidated financial statements included in this report for additional information relating to income taxes.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Security Plan for Senior Management Employees (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future stock market performance, changes in interest rates, and other factors used to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2014, with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2015 pension expense will be decreased to 4.25 percent from the 5.20 percent used in 2014.

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 yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index, and Idaho Power believes the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher. The long-term rate of return used to calculate the 2015 pension expense will be decreased to 7.5 percent from 7.75 percent for 2014.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $32 million, $55 million, and $51 million for the years ended December 31, 2014, 2013, and 2012, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2015, gross pension and other postretirement benefit costs are expected to total approximately $54 million, which takes into account the changes in the assumed long-term rate of return and discount rate noted above.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in the discount rate and rate-of-return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2015	2014	2015	2014
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (7.2)	$ (6.1)	$ (2.9)	$ (2.8)
Effect of 0.5% rate decrease on net periodic benefit cost	8.0	6.5	3.0	2.9

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $72 million decrease in the combined benefit obligations of the plans as of December 31, 2014. A 0.5 percent decrease in the plans' discount rates would have resulted in an $82 million increase in the combined benefit obligations of the plans as of December 31, 2014.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2014, a total of $64 million of expense was deferred as a regulatory asset. Approximately $24 million is expected to be deferred in 2015. Idaho Power recorded pension expense in 2014, 2013, and 2012 of $35 million, $36 million, and $34 million, respectively.

Refer to Note 11 – “Benefit Plans” to the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated, no accrual is recorded but disclosure of the contingency, if material, in the notes to the financial statements is required. Gain contingencies are not recorded until realized. IDACORP and Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria have been met, liabilities have been recorded. Estimates of this nature are highly subjective and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. As such, at IDACORP's and Idaho Power's required adoption date of January 1, 2017, amounts in 2015 and 2016 may have to be revised. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk, and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments, and derivative commodity instruments sensitive to changes in interest rates, commodity prices, and equity prices that were held at December 31, 2014. IDACORP has not entered into any of these market-risk-sensitive instruments for trading purposes.

Interest Rate Risk

IDACORP and Idaho Power manage interest expense and short- and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly-rated financial institutions may be used to achieve the desired combination.

***Variable Rate Debt*:** As of December 31, 2014, IDACORP and Idaho Power had $55.4 million and $24.1 million, respectively, in net floating rate debt. The fair market value of this debt was a respective $55.4 million and $24.1 million. Assuming no change in financial structure, if variable interest rates were to average one percentage point higher than the average rate on December 31, 2014, annual interest expense would increase and pre-tax earnings would decrease by approximately $0.5 million for IDACORP and $0.2 million for Idaho Power.

***Fixed Rate Debt*:** As of December 31, 2014, IDACORP and Idaho Power had $1.6 billion in fixed rate debt, with a fair market value equal to $1.8 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $220 million if market interest rates were to decline by one percentage point from their December 31, 2014 levels.

Commodity Price Risk

IDACORP's exposure to changes in commodity prices is related to Idaho Power's ongoing utility operations that produce electricity to meet the demand of its retail electric customers. These effects of changes in commodity prices on Idaho Power are mitigated in large part by Idaho Power's Idaho and Oregon PCA mechanisms. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of power generation. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

The primary objectives of Idaho Power’s energy purchase and sale activity are to meet the demand of retail electric customers, to maintain appropriate physical reserves to ensure reliability, and to make economic use of temporary surpluses that may develop. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power’s Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power’s Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power’s strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power only engages in a nominal amount of trading activity for non-retail purposes.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The power supply business unit produces and evaluates projections of the operating plan based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by power supply for consistency and compliance with the Policy. Idaho Power representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the board of directors for approval.

Credit Risk

IDACORP is subject to credit risk based on Idaho Power's activity with market counterparties. Idaho Power is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy, or complete financial settlement for market activities. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash, or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2014, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's energy and fuel portfolio and market conditions as of December 31, 2014, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $8.1 million. To minimize capital requirements, Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls through sensitivity analysis.

Idaho Power is obligated to provide service to all electric customers within its service area. Credit risk for Idaho Power's retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC or OPUC. Idaho Power records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. Idaho Power continuously monitors the impact of current economic conditions on nonpayment from customers and makes any necessary adjustments to its provision for uncollectible accounts accordingly.

Idaho utility customer relations rules prohibit Idaho Power from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly, or infirm persons. Idaho Power's provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC or OPUC regulations.

Equity Price Risk

IDACORP is exposed to price fluctuations in equity markets, primarily through Idaho Power's defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity security investments at Idaho Power. The equity securities held by the pension plan and in such accounts are diversified to achieve broad market participation and reduce the impact of any single investment, sector, or geographic region. Idaho Power has established asset allocation targets for the pension plan holdings, which are described in Note 11 - "Benefit Plans" to the notes to the consolidated financial statements included in this report. A hypothetical 10 percent decrease in equity prices would result in an approximate $4.5 million decrease in the fair value of financial instruments that are classified as available-for-sale securities as of December 31, 2014.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

All other schedules have been omitted because they are not required, not applicable, or the required information is otherwise included.

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31, 2014	2013	2012
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 1,122,281	$ 1,101,728	$ 937,765
Off-system sales	77,165	54,473	61,534
Other revenues	79,205	86,897	77,426
Total electric utility revenues	1,278,651	1,243,098	1,076,725
Other	3,873	3,116	3,937
Total operating revenues	1,282,524	1,246,214	1,080,662
Operating Expenses:			
Electric utility:			
Purchased power	244,628	220,579	196,935
Fuel expense	201,241	214,482	159,413
Power cost adjustment	22,235	(39,537)	(61,090)
Other operations and maintenance	354,567	348,867	349,033
Energy efficiency programs	27,154	35,636	27,300
Depreciation	132,987	129,735	123,941
Taxes other than income taxes	31,748	30,561	30,489
Total electric utility expenses	1,014,560	940,323	826,021
Other	14,268	14,149	12,039
Total operating expenses	1,028,828	954,472	838,060
Operating Income	253,696	291,742	242,602
Allowance for Equity Funds Used During Construction	17,931	14,858	22,433
Earnings of Unconsolidated Equity-Method Investments	12,372	11,939	11,617
Other Income, Net	6,328	17,013	4,209
Interest Expense:			
Interest on long-term debt	80,562	81,492	78,922
Other interest	7,703	7,203	6,876
Allowance for borrowed funds used during construction	(8,464)	(7,663)	(11,929)
Total interest expense, net	79,801	81,032	73,869
Income Before Income Taxes	210,526	254,520	206,992
Income Tax Expense	16,772	72,226	33,805
Net Income	193,754	182,294	173,187
Adjustment for (income) loss attributable to noncontrolling interests	(274)	123	(173)
Net Income Attributable to IDACORP, Inc.	$ 193,480	$ 182,417	$ 173,014
Weighted Average Common Shares Outstanding - Basic (000's)	50,131	50,052	49,930
Weighted Average Common Shares Outstanding - Diluted (000's)	50,199	50,126	50,010
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.86	$ 3.64	$ 3.47
Earnings Attributable to IDACORP, Inc. - Diluted	$ 3.85	$ 3.64	$ 3.46

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Net Income	$ 193,754	$ 182,294	$ 173,187
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $1,894, and $1,006	—	2,951	1,567
Reclassification adjustment for gains included in net income, net of tax of $0, $4,550, and $0	—	(7,087)	—
Net unrealized (losses) gains	—	(4,136)	1,567
Unfunded pension liability adjustment, net of tax of $(4,881), $3,016, and ($4,532)	(7,605)	4,699	(7,061)
Total Comprehensive Income	186,149	182,857	167,693
Comprehensive (income) loss attributable to noncontrolling interests	(274)	123	(173)
Comprehensive Income Attributable to IDACORP, Inc.	$ 185,875	$ 182,980	$ 167,520

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 56,808	$ 78,162
Receivables:		
Customer (net of allowance of $1,960 and $2,349, respectively)	79,083	97,873
Other (net of allowance of $144 and $153, respectively)	16,018	15,274
Income taxes receivable	11,867	156
Accrued unbilled revenues	56,270	63,507
Materials and supplies (at average cost)	55,404	53,643
Fuel stock (at average cost)	55,171	41,546
Prepayments	18,476	15,338
Deferred income taxes	42,359	46,874
Current regulatory assets	50,042	61,837
Other	603	2,401
Total current assets	442,101	476,611
Investments	165,424	159,072
Property, Plant and Equipment:		
Utility plant in service	5,248,212	5,080,402
Accumulated provision for depreciation	(1,841,011)	(1,766,680)
Utility plant in service - net	3,407,201	3,313,722
Construction work in progress	401,930	327,000
Utility plant held for future use	7,090	7,090
Other property, net of accumulated depreciation	17,256	17,229
Property, plant and equipment - net	3,833,477	3,665,041
Other Assets:		
American Falls and Milner water rights	13,698	15,803
Company-owned life insurance	23,893	22,037
Regulatory assets	1,192,345	978,234
Long-term receivables (net of allowance of $552 and $885, respectively)	6,317	4,811
Other	39,598	42,954
Total other assets	1,275,851	1,063,839
Total	$ 5,716,853	$ 5,364,563

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2014	December 31, 2013
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 1,064	$ 1,064
Notes payable	31,300	54,750
Accounts payable	97,271	91,519
Taxes accrued	10,367	13,302
Interest accrued	22,630	22,764
Accrued compensation	43,774	38,510
Current regulatory liabilities	11,400	10,684
Other	23,975	17,779
Total current liabilities	241,781	250,372
Other Liabilities:		
Deferred income taxes	1,065,290	969,593
Regulatory liabilities	390,207	375,873
Pension and other postretirement benefits	403,334	244,627
Other	44,238	54,100
Total other liabilities	1,903,069	1,644,193
Long-Term Debt	1,614,438	1,615,258
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 50,308,702 and 50,233,463 shares issued, respectively)	845,402	839,750
Retained earnings	1,132,237	1,027,461
Accumulated other comprehensive loss	(24,158)	(16,553)
Treasury stock (38,764 and 718 shares at cost, respectively)	(280)	(8)
Total IDACORP, Inc. shareholders' equity	1,953,201	1,850,650
Noncontrolling interests	4,364	4,090
Total equity	1,957,565	1,854,740
Total	$ 5,716,853	$ 5,364,563

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Operating Activities:			
Net income	$ 193,754	$ 182,294	$ 173,187
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	137,088	133,776	128,611
Deferred income taxes and investment tax credits	19,163	65,568	33,985
Changes in regulatory assets and liabilities	32,135	(25,581)	(53,468)
Pension and postretirement benefit plan expense	44,627	45,907	45,230
Contributions to pension and postretirement benefit plans	(33,720)	(33,393)	(47,695)
Earnings of unconsolidated equity-method investments	(12,372)	(11,939)	(11,617)
Distributions from unconsolidated equity-method investments	5,261	17,526	18,546
Allowance for equity funds used during construction	(17,931)	(14,858)	(22,433)
Gain on sale of investments and assets	(193)	(11,678)	(202)
Other non-cash adjustments to net income, net	5,085	3,297	6,121
Change in:			
Accounts receivable	20,433	(29,557)	(2,741)
Accounts payable and other accrued liabilities	6,359	(517)	10,580
Taxes accrued/receivable	(13,631)	4,747	(604)
Other current assets	(13,124)	(12,165)	(5,255)
Other current liabilities	1,771	1,819	(8,500)
Other assets	(3,655)	(830)	(7,064)
Other liabilities	(6,707)	(8,867)	(7,412)
Net cash provided by operating activities	364,343	305,549	249,269
Investing Activities:			
Additions to property, plant and equipment	(274,094)	(235,310)	(239,788)
Proceeds from the sale of utility assets	620	—	—
Proceeds from the sale of emission allowances and RECs	2,931	498	2,739
Investments in affordable housing	—	—	(381)
Distributions from affordable housing investments	1,161	1,746	242
Purchase of available-for-sale securities	(8,000)	(32,661)	(7,000)
Proceeds from sale of available-for-sale securities	—	25,661	—
Other	4,962	3,473	367
Net cash used in investing activities	(272,420)	(236,593)	(243,821)
Financing Activities:			
Issuance of long-term debt	—	150,000	150,000
Retirement of long-term debt	(1,064)	(71,064)	(101,064)
Dividends on common stock	(88,489)	(78,832)	(68,928)
Net change in short-term borrowings	(23,450)	(14,950)	15,500
Issuance of common stock	195	255	4,882
Acquisition of treasury stock	(2,737)	(2,124)	(2,062)
Other	2,268	(606)	(5,062)
Net cash used in financing activities	(113,277)	(17,321)	(6,734)
Net (decrease) increase in cash and cash equivalents	(21,354)	51,635	(1,286)
Cash and cash equivalents at beginning of the year	78,162	26,527	27,813
Cash and cash equivalents at end of the year	$ 56,808	$ 78,162	$ 26,527
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 11,364	$ 1,437	$ 1,451
Interest (net of amount capitalized)	$ 77,295	$ 77,968	$ 70,887
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 28,438	$ 24,246	$ 26,882

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 839,750	$ 834,922	$ 828,389
Issued	195	255	4,882
Other	5,457	4,573	1,651
Balance at end of year	845,402	839,750	834,922
Retained Earnings:			
Balance at beginning of year	1,027,461	923,981	819,676
Net income attributable to IDACORP, Inc.	193,480	182,417	173,014
Common stock dividends ($1.76, $1.57, and $1.37 per share, respectively)	(88,704)	(78,937)	(68,709)
Balance at end of year	1,132,237	1,027,461	923,981
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(16,553)	(17,116)	(11,622)
Net unrealized holding (loss) gain on securities (net of tax)	—	(4,136)	1,567
Unfunded pension liability adjustment (net of tax)	(7,605)	4,699	(7,061)
Balance at end of year	(24,158)	(16,553)	(17,116)
Treasury Stock:			
Balance at beginning of year	(8)	(21)	(29)
Issued	2,465	2,137	2,070
Acquired	(2,737)	(2,124)	(2,062)
Balance at end of year	(280)	(8)	(21)
Total IDACORP, Inc. shareholders' equity at end of year	1,953,201	1,850,650	1,741,766
Noncontrolling Interests:			
Balance at beginning of year	4,090	4,213	4,040
Net income (loss) attributable to noncontrolling interests	274	(123)	173
Balance at end of year	4,364	4,090	4,213
Total equity at end of year	$ 1,957,565	$ 1,854,740	$ 1,745,979

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Operating Revenues:			
General business	$ 1,122,281	$ 1,101,728	$ 937,765
Off-system sales	77,165	54,473	61,534
Other revenues	79,205	86,897	77,426
Total operating revenues	1,278,651	1,243,098	1,076,725
Operating Expenses:			
Operation:			
Purchased power	244,628	220,579	196,935
Fuel expense	201,241	214,482	159,413
Power cost adjustment	22,235	(39,537)	(61,090)
Other operations and maintenance	354,567	348,867	349,033
Energy efficiency programs	27,154	35,636	27,300
Depreciation	132,987	129,735	123,941
Taxes other than income taxes	31,748	30,561	30,489
Total operating expenses	1,014,560	940,323	826,021
Income from Operations	264,091	302,775	250,704
Other Income (Expense):			
Allowance for equity funds used during construction	17,931	14,858	22,433
Earnings of unconsolidated equity-method investments	10,814	10,242	9,412
Other (expense) income, net	(4,363)	5,772	(4,982)
Total other income	24,382	30,872	26,863
Interest Charges:			
Interest on long-term debt	80,562	81,492	78,922
Other interest	7,472	6,817	6,436
Allowance for borrowed funds used during construction	(8,464)	(7,663)	(11,929)
Total interest charges	79,570	80,646	73,429
Income Before Income Taxes	208,903	253,001	204,138
Income Tax Expense	19,516	76,260	35,970
Net Income	$ 189,387	$ 176,741	$ 168,168

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2014	**2013**	**2012**
	(thousands of dollars)		
Net Income	$ 189,387	$ 176,741	$ 168,168
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $1,894, and $1,006	—	2,951	1,567
Reclassification adjustment for gains included in net income, net of tax of $0, $4,550, and $0	—	(7,087)	—
Net unrealized (losses) gains	—	(4,136)	1,567
Unfunded pension liability adjustment, net of tax of $(4,881), $3,016, and ($4,532)	(7,605)	4,699	(7,061)
Total Comprehensive Income	$ 181,782	$ 177,304	$ 162,674

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2014	**2013**
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$ 5,248,212	$ 5,080,402
Accumulated provision for depreciation	(1,841,011)	(1,766,680)
In service - net	3,407,201	3,313,722
Construction work in progress	401,930	327,000
Held for future use	7,090	7,090
Electric plant - net	3,816,221	3,647,812
Investments and Other Property	142,825	131,520
Current Assets:		
Cash and cash equivalents	46,695	66,535
Receivables:		
Customer (net of allowance of $1,960 and $2,349, respectively)	79,083	97,873
Other (net of allowance of $144 and $153, respectively)	15,890	14,290
Income taxes receivable	20,428	—
Accrued unbilled revenues	56,270	63,507
Materials and supplies (at average cost)	55,404	53,643
Fuel stock (at average cost)	55,171	41,546
Prepayments	18,356	15,204
Deferred income taxes	—	12,386
Current regulatory assets	50,042	61,837
Other	603	2,401
Total current assets	397,942	429,222
Deferred Debits:		
American Falls and Milner water rights	13,698	15,803
Company-owned life insurance	23,893	22,037
Regulatory assets	1,192,345	978,234
Other	39,753	41,783
Total deferred debits	1,269,689	1,057,857
Total	$ 5,626,677	$ 5,266,411

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2014	**2013**
	(thousands of dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	712,258	712,258
Capital stock expense	(2,097)	(2,097)
Retained earnings	1,033,350	932,547
Accumulated other comprehensive loss	(24,158)	(16,553)
Total common stock equity	1,817,230	1,724,032
Long-term debt	1,614,438	1,615,258
Total capitalization	3,431,668	3,339,290
Current Liabilities:		
Current maturities of long-term debt	1,064	1,064
Accounts payable	96,499	90,529
Accounts payable to related parties	2,027	1,158
Taxes accrued	10,329	14,031
Interest accrued	22,630	22,764
Accrued compensation	43,410	38,297
Current regulatory liabilities	11,400	10,684
Other	29,476	17,095
Total current liabilities	216,835	195,622
Deferred Credits:		
Deferred income taxes	1,141,755	1,058,734
Regulatory liabilities	390,207	375,873
Pension and other postretirement benefits	403,334	244,627
Other	42,878	52,265
Total deferred credits	1,978,174	1,731,499
Commitments and Contingencies		
Total	$ 5,626,677	$ 5,266,411

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Operating Activities:			
Net income	$ 189,387	$ 176,741	$ 168,168
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	136,496	133,135	128,009
Deferred income taxes and investment tax credits	15,454	59,355	48,255
Changes in regulatory assets and liabilities	32,135	(25,581)	(53,467)
Pension and postretirement benefit plan expense	44,579	45,861	45,230
Contributions to pension and postretirement benefit plans	(33,672)	(33,347)	(47,695)
Earnings of unconsolidated equity-method investments	(10,814)	(10,242)	(9,412)
Distributions from unconsolidated equity-method investments	3,586	14,901	17,921
Allowance for equity funds used during construction	(17,931)	(14,858)	(22,433)
Gain on sale of investments and assets	(186)	(11,678)	(202)
Other non-cash adjustments to net income, net	2,087	629	438
Change in:			
Accounts receivable	20,072	(31,472)	(3,344)
Accounts payable	6,183	(397)	10,762
Taxes accrued/receivable	(22,911)	6,740	3,301
Other current assets	(13,137)	(12,166)	(5,252)
Other current liabilities	1,776	1,721	(8,506)
Other assets	(3,655)	(831)	(7,064)
Other liabilities	(6,238)	(8,603)	(6,856)
Net cash provided by operating activities	343,211	289,908	257,853
Investing Activities:			
Additions to utility plant	(273,911)	(235,306)	(239,761)
Proceeds from the sale of utility assets	620	—	—
Proceeds from the sale of emission allowances and RECs	2,931	498	2,739
Purchase of available-for-sale securities	(8,000)	(32,661)	(7,000)
Proceeds from the sale of available-for-sale securities	—	25,661	—
Other	4,957	3,473	367
Net cash used in investing activities	(273,403)	(238,335)	(243,655)
Financing Activities:			
Issuance of long-term debt	—	150,000	150,000
Retirement of long-term debt	(1,064)	(71,064)	(101,064)
Dividends on common stock	(88,584)	(78,926)	(68,740)
Capital contribution from parent	—	—	7,500
Other	—	(2,299)	(3,959)
Net cash used in financing activities	(89,648)	(2,289)	(16,263)
Net (decrease) increase in cash and cash equivalents	(19,840)	49,284	(2,065)
Cash and cash equivalents at beginning of the year	66,535	17,251	19,316
Cash and cash equivalents at end of the year	$ 46,695	$ 66,535	$ 17,251
Supplemental Disclosure of Cash Flow Information:			
Cash paid (received) during the year for:			
Income taxes	$ 26,116	$ 9,667	$ (14,558)
Interest (net of amount capitalized)	$ 77,063	$ 77,583	$ 70,447
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 28,438	$ 24,246	$ 26,882

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 932,547	$ 834,732	$ 735,304
Net Income	189,387	176,741	168,168
Dividends on Common Stock	(88,584)	(78,926)	(68,740)
Retained Earnings, End of Year	$ 1,033,350	$ 932,547	$ 834,732

The accompanying notes are an integral part of these statements.

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This Annual Report on Form 10-K is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (Idaho Power). Therefore, the Notes to the Consolidated Financial Statements apply to both IDACORP and Idaho Power. However, Idaho Power makes no representation as to the information relating to IDACORP's other operations.

Nature of Business

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

IDACORP's other wholly-owned subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), which is the former limited partner of, and current successor by merger to, IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. Intercompany balances have been eliminated in consolidation. Investments in subsidiaries that the companies do not control and investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

The entities that IDACORP and Idaho Power consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2014, Marysville had approximately $20 million of assets, primarily a hydroelectric plant, and approximately $13 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is identified as the primary beneficiary because of its ownership interest in the joint venture combined with the intercompany note and the EEC note, which collectively result in Ida-West's ability to control the activities of the joint ventures. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

The BCC joint venture is also a VIE, but because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner, Idaho Power is not the primary beneficiary. The carrying value of BCC was $96 million at December 31, 2014, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $70 million guarantee for mine reclamation costs, which is discussed further in Note 9.

IFS's investments in affordable housing and other real estate are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 5 to 99 percent and were acquired between 1996 and 2010. As a limited partner, IFS does not control these entities and they are not consolidated. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $13 million at December 31, 2014.

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

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

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

Cash and Cash Equivalents

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

Receivables and Allowance for Uncollectible Accounts

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

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

There were no impaired receivables without related allowances at December 31, 2014 and 2013. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

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

Revenues

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

Property, Plant and Equipment and Depreciation

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.68 percent in 2014, 2.69 percent in 2013, and 2.75 percent in 2012.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as construction work in progress on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, Idaho Power may seek recovery of such costs in customer rates, although there can be no guarantee such recovery would be granted.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment is recognized in the financial statements. There were no material impairments of these assets in 2014, 2013, or 2012.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the HCC relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power's weighted-average monthly AFUDC rate was 7.7 percent for 2014, 2013, and 2012.

Income Taxes

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

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

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

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

Income taxes are discussed in more detail in Note 2.

Other Accounting Policies

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

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. As such, at IDACORP's and Idaho Power's required adoption date of January 1, 2017, amounts in 2015 and 2016 may have to be revised. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

2. INCOME TAXES

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

	IDACORP			Idaho Power		
	2014	2013	2012	2014	2013	2012
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$ 73,588	$ 89,125	$ 72,387	$ 73,116	$ 88,550	$ 71,448
Change in taxes resulting from:						
AFUDC	(9,238)	(7,882)	(12,027)	(9,238)	(7,882)	(12,027)
Capitalized interest	2,278	1,832	5,075	2,278	1,832	5,075
Investment tax credits	(3,002)	(3,119)	(3,267)	(3,002)	(3,119)	(3,267)
Removal costs	(3,656)	(3,527)	(2,697)	(3,656)	(3,527)	(2,697)
Capitalized overhead costs	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)
Capitalized repair costs	(26,250)	(19,250)	(19,250)	(26,250)	(19,250)	(19,250)
Tax method change – capitalized repairs	(24,516)	4,583	(7,845)	(24,516)	4,583	(7,845)
State income taxes, net of federal benefit	4,680	6,730	7,801	5,334	6,970	7,646
Depreciation	16,040	14,820	14,398	16,040	14,820	14,398
Affordable housing tax credits	(5,189)	(5,503)	(5,493)	—	—	—
Affordable housing investment amortization	2,757	1,684	3,172	—	—	—
Other, net	(1,970)	1,483	(9,699)	(1,840)	2,033	(8,761)
Total income tax expense	$ 16,772	$ 72,226	$ 33,805	$ 19,516	$ 76,260	$ 35,970
Effective tax rate	8.0%	28.4%	16.3%	9.3%	30.1%	17.6%

The items comprising income tax expense are as follows:

	IDACORP			Idaho Power		
	2014	2013	2012	2014	2013	2012
	(thousands of dollars)					
Income taxes current:						
Federal	$ (4,926)	$ 3,416	$ 547	$ (2,805)	$ 10,988	$ (13,131)
State	3,516	3,241	306	6,867	5,917	846
Total	(1,410)	6,657	853	4,062	16,905	(12,285)
Income taxes deferred:						
Federal	17,159	61,947	28,315	21,833	60,934	48,839
State	(3,260)	1,806	(9,300)	(6,421)	(804)	(9,640)
Total	13,899	63,753	19,015	15,412	60,130	39,199
Investment tax credits:						
Deferred	3,044	2,344	12,323	3,044	2,344	12,323
Restored	(3,002)	(3,119)	(3,267)	(3,002)	(3,119)	(3,267)
Total	42	(775)	9,056	42	(775)	9,056
Affordable housing investment amortization	4,241	2,591	4,881	—	—	—
Total income tax expense	$ 16,772	$ 72,226	$ 33,805	$ 19,516	$ 76,260	$ 35,970

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

	IDACORP		Idaho Power	
	2014	2013	2014	2013
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 55,490	$ 55,017	$ 55,490	$ 55,017
Deferred compensation	25,355	23,739	25,240	23,647
Deferred revenue	28,529	23,063	28,529	23,063
Tax credits	154,044	149,188	26,843	23,698
Net operating losses	—	30,921	—	29,628
Partnership investments	8,190	8,195	—	—
Retirement benefits	132,571	69,033	132,571	69,033
Other	15,222	11,067	14,553	10,359
Total	419,401	370,223	283,226	234,445
Deferred tax liabilities:				
Property, plant and equipment	451,118	436,837	451,118	436,837
Regulatory assets	802,188	710,482	802,188	710,482
Power cost adjustments	23,192	35,763	23,192	35,763
Partnership investments	17,492	19,372	10,227	12,000
Retirement benefits	122,360	65,810	122,360	65,810
Other	25,982	24,678	22,252	19,901
Total	1,442,332	1,292,942	1,431,337	1,280,793
Net deferred tax liabilities	$ 1,022,931	$ 922,719	$ 1,148,111	$ 1,046,348

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

Tax Credit Carryforwards

As of December 31, 2014, IDACORP had $113.9 million of general business credit and $2.8 million of alternative minimum tax credit carryforwards for federal income tax purposes and $37.4 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2034, and the Idaho investment tax credit expires from 2021 to 2028.

Uncertain Tax Positions

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2014 and prior tax years. Both companies recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2014 for federal and 2011-2014 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2014, the IRS completed its examination of IDACORP's 2013 tax year with no unresolved income tax issues.

Tax Accounting Method Changes for Repair-Related Expenditures

In the fourth quarter of 2014, Idaho Power finalized an income tax accounting method change for its 2014 tax year associated with the electric generation property portion of its capitalized repairs tax method it adopted in fiscal year 2010. As a result of the change, Idaho Power recorded an $8.8 million tax benefit related to the cumulative method change adjustment for years prior to 2014 and reversed a related $4.6 million tax expense estimate it had recorded in 2013 (discussed below), for a total adjustment of $13.4 million.

The method change is pursuant to Revenue Procedure 2013-24 and will bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric generation property. The change also incorporates provisions of the final tangible property regulations issued by the U.S. Treasury Department (Treasury) and IRS in the third quarter of 2013 that address the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power expects to adopt this method with the filing of IDACORP’s 2014 consolidated federal income tax return in September 2015. The method change will be subject to IRS review as part of IDACORP’s CAP examination.

In the third quarter of 2014, Idaho Power, in coordination with the IRS through IDACORP’s CAP examination process, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in the third quarter. Idaho Power finalized these changes with the filing of IDACORP’s 2013 consolidated federal income tax return in September 2014. The IRS approved the repairs method modifications prior to the filing of the return as part of IDACORP’s 2013 CAP examination.

In connection with the issuance of the tangible property regulations and following the provisions of Revenue Procedure 2013-24 (discussed above), in the third quarter of 2013 Idaho Power assessed and estimated the impact of a method change associated with the electric generation property portion of its capitalized repairs method. Based upon this assessment, in 2013 Idaho Power recorded $4.6 million of income tax expense related to the estimated cumulative method change adjustment for years prior to 2013.

In the third quarter of 2012, Idaho Power completed an income tax accounting method change for its 2011 tax year associated with the electric transmission and distribution property portion (as opposed to the generation property portion described above) of the capitalized repairs method it adopted in fiscal year 2010. As a result of the change, in 2012 Idaho Power recorded a $7.8 million tax benefit related to the filed deduction for the cumulative method change adjustment for years prior to 2011. The change was made pursuant to Revenue Procedure 2011-43 to bring Idaho Power’s existing method into alignment with the Revenue Procedure’s safe harbor unit-of-property definitions for electric transmission and distribution property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP’s 2011 consolidated federal income tax return. The IRS approved the method change prior to the filing of the return as part of IDACORP’s 2011 CAP examination. The final tangible property regulations issued in September 2013 did not adversely impact this tax accounting method.

The amount of the capitalized repairs annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power’s annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power’s prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type, commonly referred to as “flow-through.” A net regulatory asset is established to reflect Idaho Power’s ability to recover the net increased income tax expense when such temporary differences reverse. Idaho Power’s 2014 capitalized repairs deduction estimate incorporates the provisions of both method changes.

3. REGULATORY MATTERS

Included below is information on Idaho Power's regulatory assets and liabilities, as well as a summary of Idaho Power's most recent general rate changes and other notable recent or pending regulatory matters and proceedings.

Regulatory Assets and Liabilities

The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would record such expenses and revenues. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense. The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

		As of December 31, 2014		Total as of December 31,	
Description	**Remaining Amortization Period**	**Earning a Return[1]**	**Not Earning a Return**	**2014**	**2013**
Regulatory Assets:					
Income taxes		$ —	$ 802,188	$ 802,188	$ 710,482
Unfunded postretirement benefits[2]		—	264,548	264,548	116,583
Pension expense deferrals		40,816	22,828	63,644	75,108
Energy efficiency program costs[3]		4,690	—	4,690	3,694
Power supply costs[3]	Varies	59,189	—	59,189	91,477
Fixed cost adjustment[3]	2015-2016	23,737	—	23,737	19,526
Asset retirement obligations[4]		—	17,309	17,309	18,026
Mark-to-market liabilities[5]		—	3,961	3,961	1,629
Other	2015-2021	1,215	1,906	3,121	3,546
Total		$ 129,647	$ 1,112,740	$ 1,242,387	$ 1,040,071
Regulatory Liabilities:					
Income taxes		$ —	$ 55,490	$ 55,490	$ 55,017
Removal costs[4]		—	180,063	180,063	173,974
Investment tax credits		—	79,163	79,163	79,121
Deferred revenue-AFUDC[6]		48,306	24,669	72,975	58,991
Energy efficiency program costs[3]		—	—	—	6,686
Power supply costs[3]	Varies	1	—	1	24
Settlement agreement sharing mechanism[3]	2015-2016	7,999	—	7,999	7,602
Mark-to-market assets[5]		—	1,880	1,880	1,672
Other		3,114	922	4,036	3,470
Total		$ 59,420	$ 342,187	$ 401,607	$ 386,557

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) These items are discussed in more detail in this Note 3.
(4) Asset retirement obligations and removal costs are discussed in Note 13.
(5) Mark-to-market assets and liabilities are discussed in Note 16.
(6) As part of its January 30, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the HCC relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power has collected revenue in the Idaho jurisdiction for these relicensing costs, but is deferring revenue recognition of the amounts collected until the license is issued and the asset is placed in service under the new license.

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

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

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

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

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a load change adjustment rate, which is intended to ensure that power supply expense fluctuations resulting solely from load changes do not distort the results of the mechanism.

The table below summarizes the three most recent Idaho PCA rate adjustments, all of which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	$ Change (millions)	Notes
June 1, 2014	$ (88.2)	2014 PCA rates are net of (a) $20.0 million of surplus Idaho energy efficiency rider funds, and (b) $7.6 million of customer revenue sharing under a regulatory settlement stipulation. In addition, on June 1, 2014, there was an increase in base net power supply costs that shifted $99.3 million in power supply expenses from recovery via the PCA mechanism to recovery via base rates. See further discussion of the change in base net power supply costs below.
June 1, 2013	$ 140.4	The 2013 PCA rate increase was net of $7.2 million of customer revenue sharing under regulatory settlement stipulations.
June 1, 2012	$ 15.9	2012 PCA rates were net of $27.1 million of customer revenue sharing under a regulatory settlement stipulation.

On November 1, 2013, Idaho Power filed an application with the IPUC requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that would become effective June 1, 2014. Idaho Power's request was intended to remove the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead collect that portion through base rates. On March 21, 2014, the IPUC issued an order approving Idaho Power's application, with the change in collection methodology effective June 1, 2014.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual Oregon-jurisdictional return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2014, 2013, and 2012 are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2014 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.
2013 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2013 APCU	A rate increase of $2.9 million annually took effect June 1, 2013.
2012 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2012 APCU	A rate increase of $1.8 million annually took effect June 1, 2012.

Idaho Regulatory Matters

Idaho Base Rate Changes: Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from IPUC approval of a settlement stipulation that provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. Idaho base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Neither the settlement stipulation nor the IPUC orders adjusting base rates specified an authorized rate of return on equity or imposed a moratorium on Idaho Power filing a general rate case at a future date.

As noted above in this Note 3, the IPUC also issued a March 2014 order approving Idaho Power's request for an increase in the normalized or "base level" net power supply expense to be used to update base rates and in the determination of the Idaho PCA rate that would become effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that provided as follows:

- If Idaho Power's actual Idaho-jurisdiction return on year-end equity (Idaho ROE) for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA mechanism adjustment.
- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

As Idaho Power's Idaho ROE exceeded 10.5 percent for each of 2012, 2013, and 2014, Idaho Power did not amortize additional ADITC for those years, but instead shared a portion of its Idaho-jurisdiction earnings with Idaho customers. The amounts Idaho Power recorded in each of 2012, 2013, and 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation were as follows (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense
2014	$8.0	$16.7
2013	$7.6	$16.5
2012	$7.2	$14.6

October 2014 Idaho Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation are as follows:

- If Idaho Power's annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.5 percent Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.0 percent, the amount of earnings exceeding a 10.0 percent Idaho ROE and up to and including a 10.5 percent Idaho ROE will be allocated 75 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment and 25 percent to Idaho Power.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.5 percent, the amount of earnings exceeding a 10.5 percent Idaho ROE will be allocated 50 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to Idaho Power's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be adjusted prospectively.

Neither the settlement stipulation nor the associated IPUC order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the term of the settlement stipulation.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism is designed to remove Idaho Power’s financial disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA mechanism is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual (weather-normalized) fixed costs recovered by Idaho Power during the year. The amount of the FCA recovery is capped at no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The following table summarizes FCA amounts approved for collection in the prior three FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9
2011	June 1, 2012-May 31, 2013	$10.3

On July 1, 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA mechanism. Concerns cited by interested parties included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA mechanism is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. Proceedings in the FCA mechanism docket, which remains open, could result in significant changes to the FCA mechanism.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. The December 2011 IPUC general rate case settlement order described above reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date. As of December 31, 2014, the Idaho energy efficiency rider balance was a regulatory asset of $0.8 million.

On June 12, 2013, the IPUC issued an order authorizing Idaho Power to recover custom efficiency program incentive payments, including the then-current regulatory asset balance of approximately $14 million, as well as subsequent custom efficiency program incentive payments, through the Idaho energy efficiency rider mechanism. As a result of the order, Idaho Power recognized the balance as other revenue and energy efficiency program expenses in 2013.

Oregon Regulatory Matters

Oregon Base Rate Changes: On February 23, 2012, the OPUC issued an order approving a settlement stipulation that provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. Subsequently, on September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

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

Applicable Period	OATT Rate (per kW-year)
October 1, 2014 to September 30, 2015	$ 22.71
October 1, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.32
October 1, 2011 to September 30, 2012	$ 19.79

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $120.8 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. LONG-TERM DEBT

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

	2014	2013
First mortgage bonds:		
6.025% Series due 2018	$ 120,000	$ 120,000
6.15% Series due 2019	100,000	100,000
4.50% Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	100,000
2.95% Series due 2022	75,000	75,000
2.50% Series due 2023	75,000	75,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	75,000
4.00% Series due 2043	75,000	75,000
Total first mortgage bonds	1,425,000	1,425,000
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	3,191	4,255
Unamortized premium/discount - net	(3,034)	(3,278)
Total IDACORP and Idaho Power outstanding debt(2)	1,615,502	1,616,322
Current maturities of long-term debt	(1,064)	(1,064)
Total long-term debt	$ 1,614,438	$ 1,615,258

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2014 to $1.591 billion.
(2) At December 31, 2014 and 2013, the overall effective cost of Idaho Power's outstanding debt was 5.19 percent.

At December 31, 2014, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2015	2016	2017	2018	2019	Thereafter
$ 1,064	$ 1,064	$ 1,064	$ 120,000	$ 100,000	$ 1,395,344

Long-Term Debt Issuances, Maturities, and Availability

On April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds, Series I, maturing on April 1, 2023, and $75 million in principal amount of 4.00% first mortgage bonds, Series I, maturing on April 1, 2043. On October 1, 2013, Idaho Power used a portion of the net proceeds of the April 2013 sale of first mortgage bonds to satisfy its obligations upon maturity of $70 million in principal amount of 4.25% first mortgage bonds.

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

In anticipation of the expiration of the prior registration statement, on May 22, 2013, IDACORP and Idaho Power filed a joint shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of, in the case of Idaho Power, an unspecified principal amount of its first mortgage bonds and debt securities. On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds, secured medium term notes, Series J (Series J Notes), under Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes pursuant to the Indenture. As of December 31, 2014, Idaho Power had not sold any first mortgage bonds, including Series J Notes, or debt securities under the Selling Agency Agreement.

***Mortgage*:** As of December 31, 2014, Idaho Power could issue under its Indenture approximately $1.6 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Indenture.

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

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

5. NOTES PAYABLE

Credit Facilities

IDACORP and Idaho Power have in place credit facilities that may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

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

At December 31, 2014, no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2014, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of IDACORP’s and Idaho Power's short-term borrowings were as follows at December 31, 2014 and December 31, 2013:

	IDACORP		Idaho Power		Total	
	2014	**2013**	**2014**	**2013**	**2014**	**2013**
Commercial paper balances:						
At the end of year	$ 31,300	$ 54,750	$ —	$ —	$ 31,300	$ 54,750
Average during the year	$ 37,786	$ 61,121	$ —	$ 2,209	$ 37,786	$ 63,330
Weighted-average interest rate						
At the end of the year	0.43%	0.34%	—%	—%	0.43%	0.34%

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes common stock transactions during the last three years and shares reserved at December 31, 2014:

	Shares issued			Shares reserved
	2014	**2013**	**2012**	**December 31, 2014**
Balance at beginning of year	50,233,463	50,158,486	49,964,172	
Continuous equity program	—	—	—	3,000,000
Dividend reinvestment and stock purchase plan	—	—	62,084	2,576,723
Employee savings plan	—	—	49,296	3,567,954
Long-term incentive and compensation plan	75,239	74,977	82,934	1,469,234
Restricted stock plan	—	—	—	256,154
Balance at end of year	50,308,702	50,233,463	50,158,486	

IDACORP enters into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. On July 12, 2013, IDACORP entered into its current Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM). IDACORP may offer and sell up to 3 million shares of its common stock from time to time in at-the-market offerings through BNYMCM as IDACORP's agent. IDACORP has no obligation to issue any minimum number of shares under the Sales Agency Agreement. As of the date of this report, no shares of IDACORP common stock have been issued under the current Sales Agency Agreement.

Idaho Power Common Stock

In 2012, IDACORP contributed $7.5 million of additional equity to Idaho Power. No contributions were made to Idaho Power in 2014 or 2013. No additional shares of Idaho Power common stock were issued in exchange for the contribution.

Restrictions on Dividends

Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants in their respective credit facilities or Idaho Power's Revised Code of Conduct. A covenant under IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2014, the leverage ratios for IDACORP and Idaho Power were 46 percent and 47 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $1.1 billion and $944 million, respectively, at December 31, 2014. There are additional facility covenants, subject to exceptions, that prohibit or restrict the sale or disposition of property without consent and any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2014, IDACORP and Idaho Power were in compliance with those covenants.

Idaho Power's Revised Policy and Code of Conduct relating to transactions between and among Idaho Power, IDACORP, and other affiliates, which was approved by the IPUC in April 2008, provides that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2014, Idaho Power's common equity capital was 53 percent of its total adjusted capital. Further, Idaho Power must obtain approval from the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

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

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the Federal Power Act or its regulations, but Idaho Power does not believe the restriction would limit Idaho Power's ability to pay dividends out of current year earnings or retained earnings.

7. STOCK-BASED COMPENSATION

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

The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP (for officers and key employees) permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2014, the maximum number of shares available under the LTICP and RSP were 1,166,210 and 15,796, respectively, excluding (i) issued but unvested performance-based restricted shares and (ii) issued but unvested time-based restricted shares.

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

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. The performance conditions are two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. Depending on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The grant-date fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The grant-date fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock and performance share activity is presented below. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	IDACORP		Idaho Power	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2014	310,379	$ 36.88	305,984	$ 36.85
Shares granted	106,527	48.75	105,367	48.74
Shares forfeited	(35,298)	46.34	(35,298)	46.34
Shares vested	(126,535)	30.09	(125,657)	30.09
Nonvested shares at December 31, 2014	255,073	$ 43.90	250,396	$ 43.91

The total fair value of shares vested during the years ended December 31, 2014, 2013, and 2012 was $6.6 million, $5.0 million, and $4.9 million, respectively. At December 31, 2014, IDACORP had $4.6 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4.6 million. These costs are expected to be recognized over a weighted-average period of 1.69 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2014, a total of 14,599 shares were awarded to directors at a grant date fair value of $56.05 per share. Directors elected to defer receipt of 8,004 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: IDACORP has not granted any stock option awards since 2006 and has no plans to do so in the future. At December 31, 2014, there were no outstanding options.

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

	IDACORP			Idaho Power		
	2014	2013	2012	2014	2013	2012
Compensation cost	$ 5,609	$ 4,888	$ 4,696	$ 5,458	$ 4,783	$ 4,577
Income tax benefit	2,193	1,911	1,836	2,134	1,870	1,789

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share (EPS) for the years ended December 31, 2014, 2013, and 2012 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2014	2013	2012
Numerator:			
Net income attributable to IDACORP, Inc.	$ 193,480	$ 182,417	$ 173,014
Denominator:			
Weighted-average common shares outstanding - basic	50,131	50,052	49,930
Effect of dilutive securities	68	74	80
Weighted-average common shares outstanding - diluted	50,199	50,126	50,010
Basic earnings per share	$ 3.86	$ 3.64	$ 3.47
Diluted earnings per share	$ 3.85	$ 3.64	$ 3.46

9. COMMITMENTS

Purchase Obligations

At December 31, 2014, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2015	2016	2017	2018	2019	Thereafter
Cogeneration and power production	$ 181,468	$ 189,493	$ 229,255	$ 240,280	$ 238,501	$4,064,213
Power and transmission rights	6,370	5,416	3,337	1,199	1,105	4,487
Fuel	64,415	42,124	41,744	9,352	9,169	68,359

As of December 31, 2014, Idaho Power had 781 MW nameplate capacity of PURPA-related projects on-line, with an additional 521 MW nameplate capacity of projects projected to be on-line by June 1, 2017. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. Idaho Power's expenses associated with PURPA-related projects were approximately $145 million in 2014, $131 million in 2013, and $118 million in 2012.

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

	2015	2016	2017	2018	2019	Thereafter
Operating leases	$ 162	$ 1,039	$ 1,065	$ 1,088	$ 1,167	$ 14,136
Equipment, maintenance, and service agreements	61,492	19,610	8,279	7,794	7,978	31,489
FERC and other industry-related fees	12,954	6,813	6,813	6,813	6,813	34,063

IDACORP's expense for operating leases was approximately $5.9 million in 2014, $5.3 million in 2013, and $6.1 million in 2012.

Guarantees

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was $70 million at December 31, 2014, representing IERCo's one-third share of BCC's total reclamation obligation. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2014, the value of the reclamation trust fund was $67 million. During 2014 the reclamation trust fund distributed approximately $13 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

IDACORP and Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2014, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. IDACORP and Idaho Power monitor those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, IDACORP and Idaho Power do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, IDACORP's and Idaho Power's accruals for loss contingencies are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending proceedings and predict that these matters will not have a material adverse effect on IDACORP's or Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds in the Pacific Northwest markets from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC has characterized these ripple claims as "speculative." However, the FERC has refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve portions of two settlements that provided for waivers of claims in those proceedings, despite only limited objections from two market participants to one of the two settlements and no objections to the other settlement. Idaho Power and IESCo have petitions for review of the FERC's decisions refusing to approve the waiver provision of the settlements, on the basis that the FERC failed to apply its established precedents and rules. The petitions for review are pending in the Ninth Circuit Court of Appeals.

Based on its evaluation of the merits of ripple claims and the inability to estimate the potential exposure should the claims ultimately have any merit, particularly in light of Idaho Power and IESCo being both purchasers and sellers in the energy market during the relevant period, Idaho Power and IESCo have no amount accrued relating to the proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Other Proceedings

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the companies believe that resolution of those matters will not have a material adverse effect on their respective consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations, including the EPA's proposed rule under Section 111(d) of the Clean Air Act, that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to estimate the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

11. BENEFIT PLANS

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

Pension Plans

Idaho Power has two pension plans – a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit pension plan for certain senior management employees called the Security Plan for Senior Management Employees (SMSP). Idaho Power also has a nonqualified defined benefit pension plan for directors that was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power's funding policy for the pension plan is to contribute at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2014, 2013, and 2012 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

	Pension Plan		SMSP	
	2014	2013	2014	2013
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 695,093	$ 767,692	$ 77,773	$ 80,515
Service cost	25,292	31,357	1,645	2,178
Interest cost	35,415	31,830	3,856	3,258
Actuarial loss (gain)	114,496	(112,215)	15,324	(4,663)
Benefits paid	(25,484)	(23,571)	(4,188)	(3,515)
Projected benefit obligation at December 31	844,812	695,093	94,410	77,773
Change in plan assets:				
Fair value at January 1	545,092	460,862	—	—
Actual return on plan assets	10,111	77,801	—	—
Employer contributions	30,000	30,000	—	—
Benefits paid	(25,484)	(23,571)	—	—
Fair value at December 31	559,719	545,092	—	—
Funded status at end of year	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,193)	$ (3,905)
Noncurrent liabilities	(285,093)	(150,001)	(90,217)	(73,868)
Net amount recognized	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 263,350	$ 120,587	$ 38,808	$ 26,102
Prior service cost	295	642	857	1,077
Subtotal	263,645	121,229	39,665	27,179
Less amount recorded as regulatory asset	(263,645)	(121,229)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 39,665	$ 27,179
Accumulated benefit obligation	$ 719,617	$ 591,649	$ 84,684	$ 70,530

The actuarial loss affecting the change in projected benefit obligations from December 31, 2013 to December 31, 2014 is due to the reduction in the discount rates, as identified in the plan assumptions table included later in this footnote.

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. The fair value of these investments was approximately $65.0 million and $59.2 million at December 31, 2014 and 2013, respectively, and is reflected in Investments and in Company-owned life insurance on the consolidated balance sheets.

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

	Pension Plan			SMSP		
	2014	2013	2012	2014	2013	2012
Service cost	$ 25,292	$ 31,357	$ 25,571	$ 1,645	$ 2,178	$ 2,151
Interest cost	35,415	31,830	31,489	3,856	3,258	3,218
Expected return on assets	(42,289)	(35,755)	(31,737)	—	—	—
Amortization of net loss	3,911	17,118	14,114	2,618	2,840	1,530
Amortization of prior service cost	347	347	347	220	212	212
Net periodic pension cost	22,676	44,897	39,784	8,339	8,488	7,111
Adjustments due to the effects of regulation[1]	12,124	(9,013)	(5,860)	—	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,800	$ 35,884	$ 33,924	$ 8,339	$ 8,488	$ 7,111

[1] Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates.

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

	Pension Plan			SMSP		
	2014	2013	2012	2014	2013	2012
Actuarial (loss) gain during the year	$ (146,674)	$ 154,261	$ (60,448)	$ (15,324)	$ 4,664	$ (13,335)
Reclassification adjustments for:						
Amortization of net loss	3,911	17,118	14,114	2,618	2,840	1,530
Amortization of prior service cost	347	347	347	220	212	212
Adjustment for deferred tax effects	55,678	(67,136)	17,979	4,881	(3,017)	4,532
Adjustment due to the effects of regulation	86,738	(104,590)	28,008	—	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ —	$ (7,605)	$ 4,699	$ (7,061)

In 2015, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $18.8 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2014, relating to the pension plan and SMSP. This amount consists of $14.2 million of amortization of net loss and $0.2 million of amortization of prior service cost for the pension plan, and $4.2 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2015	2016	2017	2018	2019	2020-2024
Pension Plan	$ 27,634	$ 29,938	$ 32,428	$ 35,036	$ 37,644	$ 226,411
SMSP	4,274	4,198	4,262	4,134	4,291	23,868

As of December 31, 2014, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2015, though Idaho Power plans to contribute at least $20 million to the pension plan during 2015.

Postretirement Benefits

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

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

	2014	2013
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 57,341	$ 72,547
Service cost	1,011	1,315
Interest cost	2,841	2,633
Actuarial loss (gain)	7,026	(16,788)
Benefits paid[1]	(2,220)	(2,366)
Benefit obligation at December 31	65,999	57,341
Change in plan assets:		
Fair value of plan assets at January 1	37,111	33,387
Actual return on plan assets	3,888	6,212
Employer contributions[1]	(404)	(122)
Benefits paid[1]	(2,220)	(2,366)
Fair value of plan assets at December 31	38,375	37,111
Funded status at end of year (included in noncurrent liabilities)	$ (27,624)	$ (20,230)

[1] Contributions and benefits paid are each net of $3,379 thousand and $3,272 thousand of plan participant contributions, and $344 thousand and $372 thousand of Medicare Part D subsidy receipts for 2014 and 2013, respectively.

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

	2014	2013
Net loss	$ 759	$ (4,974)
Prior service cost	145	328
Subtotal	904	(4,646)
Less amount recognized in regulatory assets	(904)	4,646
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2014	2013	2012
Service cost	$ 1,011	$ 1,315	$ 1,292
Interest cost	2,841	2,633	3,135
Expected return on plan assets	(2,595)	(2,328)	(2,234)
Amortization of net loss	—	98	384
Amortization of prior service cost	183	(229)	(422)
Amortization of unrecognized transition obligation	—	—	2,040
Net periodic postretirement benefit cost	$ 1,440	$ 1,489	$ 4,195

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

	2014	2013	2012
Actuarial (loss) gain during the year	$ (5,733)	$ 20,673	$ (2,068)
Reclassification adjustments for:			
Amortization of net loss	—	98	384
Amortization of prior service cost	183	(229)	(422)
Amortization of unrecognized transition obligation	—	—	2,040
Adjustment for deferred tax effects	2,170	(8,031)	(153)
Adjustment due to the effects of regulation	3,380	(12,511)	219
Other comprehensive income related to postretirement benefit plans	$ —	$ —	$ —

In 2015, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents $15 thousand of amortization of prior service cost.

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

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

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	$ 3,970	$ 4,040	$ 4,090	$ 4,160	$ 4,210	$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2014	2013	2014	2013	2014	2013
Discount rate	4.25%	5.20%	4.20%	5.10%	4.20%	5.15%
Rate of compensation increase[(1)]	4.30%	4.38%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.4%	6.8%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

(1) The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

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

	Pension Plan			SMSP			Postretirement Benefits		
	2014	2013	2012	2014	2013	2012	2014	2013	2012
Discount rate	5.20%	4.20%	4.90%	5.10%	4.15%	5.10%	5.15%	4.20%	5.05%
Expected long-term rate of return on assets	7.75%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.30%	4.38%	4.35%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	6.4%	6.8%	6.5%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 325	$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2014 for the pension asset portfolio by asset class is set forth below:

Asset Class	**Target Allocation**	**Actual Allocation December 31, 2014**
Debt securities	24%	24%
Equity securities	54%	55%
Real estate	6%	6%
Other plan assets	16%	15%
Total	100%	100%

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

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

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

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

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

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

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

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 16. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2014				
Pension plan assets:				
Cash and cash equivalents	$ 19,190	$ —	$ —	$ 19,190
Short-term bonds	—	10,991	—	10,991
Intermediate bonds	—	101,867	—	101,867
Long-term bonds	—	21,615	—	21,615
Equity Securities: Large-Cap	66,151	—	—	66,151
Equity Securities: Mid-Cap	68,974	—	—	68,974
Equity Securities: Small-Cap	50,972	—	—	50,972
Equity Securities: Micro-Cap	22,962	—	—	22,962
Equity Securities: International	6,555	57,705	—	64,260
Equity Securities: Emerging Markets	8,629	22,915	—	31,544
Real estate	—	—	33,996	33,996
Private market investments	—	—	37,118	37,118
Commodities funds	—	30,079	—	30,079
Total pension assets	$ 243,433	$ 245,172	$ 71,114	$ 559,719
Postretirement plan assets[1]	$ 11	$ 38,364	$ —	$ 38,375
Assets at December 31, 2013				
Pension plan assets:				
Cash and cash equivalents	$ 33,030	$ —	$ —	$ 33,030
Short-term bonds	—	11,068	—	11,068
Intermediate bonds	—	76,312	—	76,312
Long-term bonds	—	19,024	—	19,024
Equity Securities: Large-Cap	71,042	—	—	71,042
Equity Securities: Mid-Cap	23,346	23,112	—	46,458
Equity Securities: Small-Cap	48,998	—	—	48,998
Equity Securities: Micro-Cap	24,687	—	—	24,687
Equity Securities: International	19,128	74,908	—	94,036
Equity Securities: Emerging Markets	3,523	22,107	—	25,630
Equity Securities: Market Neutral	3,870	—	—	3,870
Real estate	—	—	28,019	28,019
Private market investments	—	—	33,709	33,709
Commodities funds	—	29,209	—	29,209
Total pension assets	$ 227,624	$ 255,740	$ 61,728	$ 545,092
Postretirement plan assets[1]	$ 75	$ 37,036	$ —	$ 37,111

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

For the year ended December 31, 2014, the only significant transfer in and out of Levels 1, 2, or 3 was $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1. For the year ended December 31, 2013, there were no significant transfers into or out of Levels 1, 2, or 3.

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

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2013	$ 30,507	$ 27,874	$ 58,381
Realized gains	—	739	739
Unrealized gains	2,941	1,579	4,520
Purchases	89	4,726	4,815
Sales	—	(6,899)	(6,899)
Settlements	172	—	172
Ending balance - December 31, 2013	33,709	28,019	61,728
Realized gains	1,430	866	2,296
Unrealized (losses) gains	(545)	1,305	760
Purchases	2,434	3,806	6,240
Settlements	90	—	90
Ending balance - December 31, 2014	$ 37,118	$ 33,996	$ 71,114

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

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

Level 2 Postretirement Assets: These assets represent an investment in a life insurance contract and are recorded at fair value, which is the cash surrender value, less any unpaid expenses. The cash surrender value of this insurance contract is contractually equal to the insurance contract's proportionate share of the market value of an associated investment account held by the insurer. The investments held by the insurer's investment account are all instruments traded on exchanges with readily determinable market prices.

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

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

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

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately $7 million each year from 2012 to 2014.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and Idaho Power's consolidated balance sheets at December 31, 2014 and 2013 are $2.0 million and $1.9 million, respectively.

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

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2014 and 2013 (in thousands of dollars):

	2014		2013	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,316,941	2.48%	$ 2,272,381	2.47%
Transmission	1,016,207	2.03%	974,697	2.01%
Distribution	1,516,933	2.72%	1,459,666	2.72%
General and Other	398,131	5.49%	373,658	5.91%
Total in service	5,248,212	2.68%	5,080,402	2.69%
Accumulated provision for depreciation	(1,841,011)		(1,766,680)	
In service - net	$ 3,407,201		$ 3,313,722	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses for each facility is included in the Consolidated Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2014 (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	$ 569,220	$ 59,394	$ 293,432	33	771
Boardman	Boardman, OR	80,951	125	60,031	10	64
Valmy Units 1 and 2	Winnemucca, NV	372,791	19,023	193,756	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $79 million in 2014 and 2013, and $75 million in 2012.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9 million each year from 2012 to 2014.

See Note 1 for a discussion of the property of IDACORP's consolidated VIE.

13. ASSET RETIREMENT OBLIGATIONS (ARO)

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

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyl-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2014, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net decrease of $4.1 million in the recorded AROs. The decrease in the AROs in 2014 is primarily due to decreases in estimated future costs related to evaporation ponds at the Valmy generating facility.

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

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the removal costs recorded as regulatory liabilities on IDACORP's and Idaho Power's consolidated balance sheets as of December 31, 2014 and 2013.

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

	2014	2013
Balance at beginning of year	$ 25,765	$ 22,982
Accretion expense	1,061	1,041
Revisions in estimated cash flows	(4,140)	2,722
Liability settled	(756)	(980)
Balance at end of year	$ 21,930	$ 25,765

14. INVESTMENTS

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

	2014	2013
Idaho Power investments:		
Bridger Coal Company (equity method investment)	$ 96,219	$ 88,990
Available-for-sale equity securities	44,942	41,119
Executive deferred compensation plan investments	141	1,153
Other investments	1	1
Total Idaho Power investments	141,303	131,263
Investments in affordable housing (IDACORP Financial Services)	12,762	17,372
Ida-West joint ventures (equity method investments)	11,393	11,454
Total IDACORP investments	$ 165,458	$ 160,089

Equity Method Investments

Idaho Power, through its subsidiary IERCo, is a 33 percent owner of BCC. Ida-West, through separate subsidiaries, owns 50 percent of three electric generation projects that are accounted for using the equity method: South Forks Joint Venture; Hazelton/Wilson Joint Venture, and Snow Mountain Hydro LLC. All projects are reviewed periodically for impairment. The table below presents IDACORP's and Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

	2014	2013	2012
Bridger Coal Company (Idaho Power)	$ 10,814	$ 10,242	$ 9,412
Ida-West joint ventures	1,614	1,707	2,215
Other	(56)	(10)	(10)
Total	$ 12,372	$ 11,939	$ 11,617

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value. Any unrealized gains or losses on available-for-sale securities are included in income, as the fair value option has been elected for these instruments. Unrealized gains and losses on available-for-sale securities were immaterial at December 31, 2014 and December 31, 2013.

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

	2014	2013	2012
Proceeds from sales	$ —	$ 25,661	$ —
Gross realized gains from sales	—	11,637	—
Gross realized losses from sales	—	—	—

At the end of each reporting period, IDACORP and Idaho Power analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2014 and December 31, 2013, there were no indicators of other-than-temporary impairment related to IDACORP's and Idaho Power's investments.

Investments in Affordable Housing

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk with most of IFS's investments having been made through syndicated funds.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

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

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges. Idaho Power offsets fair value amounts recognized on its balance sheet and applies collateral related to derivative instruments executed with the same counterparty under the same master netting agreement. Idaho Power does not offset a counterparty's current derivative contracts with the counterparty's long-term derivative contracts, although Idaho Power's master netting arrangements would allow current and long-term positions to be offset in the event of default. Also, in the event of default, Idaho Power's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting presented in the derivative fair value and offsetting table below.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31, 2014 and 2013 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[(1)]		
		2014	2013	2012
Financial swaps	Off-system sales	$ (4,119)	$ (2,637)	$ 15,104
Financial swaps	Purchased power	(1,416)	947	(6,280)
Financial swaps	Fuel expense	3,862	731	(6,359)
Financial swaps	Other operations and maintenance	(158)	35	(302)
Forward contracts	Off-system sales	277	185	—
Forward contracts	Purchased power	(279)	(196)	—
Forward contracts	Fuel expense	94	217	(1,755)

(1) Excludes unrealized gains or losses on derivatives, which are recorded on the balance sheet as regulatory assets or regulatory liabilities.

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 16 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Derivative Instrument Summary

The table below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets and reconciles the gross amounts of derivatives recognized as assets and as liabilities to the net amounts presented in the balance sheets at December 31, 2014 and 2013 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
December 31, 2014							
Current:							
Financial swaps	Other current assets	$ 2,509	$ (2,002) [1]	$ 507	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	379	(379)	—	4,335	(379)	3,956
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	5	—	5
Long-term:							
Forward contracts	Other assets	63	—	63	—	—	—
Total		$ 3,015	$ (2,381)	$ 634	$ 5,096	$ (1,135)	$ 3,961
December 31, 2013							
Current:							
Financial swaps	Other current assets	$ 1,451	$ (175)	$ 1,276	$ 175	$ (175)	$ —
Financial swaps	Other current liabilities	373	(373)	—	1,975	(1,429) [1]	546
Forward contracts	Other current assets	109	—	109	—	—	—
Forward contracts	Other current liabilities	—	—	—	26	—	26
Long-term:							
Financial swaps	Other assets	189	(28)	161	28	(28)	—
Forward contracts	Other assets	126	—	126	—	—	—
Total		$ 2,248	$ (576)	$ 1,672	$ 2,204	$ (1,632)	$ 572

[1] Current asset and current liability derivative amounts offset include $1.2 million and $1.1 million of collateral payable and receivable for the periods ending December 31, 2014 and 2013, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2014 and 2013 (in thousands of units):

		December 31,	
Commodity	Units	2014	2013
Electricity purchases	MWh	115	89
Electricity sales	MWh	238	603
Natural gas purchases	MMBtu	6,913	10,804
Natural gas sales	MMBtu	409	555
Diesel purchases	Gallons	243	906

Credit Risk

At December 31, 2014, Idaho Power did not have material credit risk exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are commonly under Western Systems Power Pool agreements, physical gas contracts are usually under North American Energy Standards Board contracts, and financial transactions are usually under International Swaps and Derivatives Association, Inc. contracts. These contracts contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2014, was $5.1 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2014, Idaho Power would have been required to post an additional $5.9 million of cash collateral to its counterparties.

16. FAIR VALUE MEASUREMENTS

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

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

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

- Level 2: Financial assets and liabilities whose values are based on 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.

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

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

IDACORP's and Idaho Power's assessment of a particular input's significance 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. An item recorded at fair value is reclassified among levels when changes in the nature of valuation inputs cause the item to no longer meet the criteria for the level in which it was previously categorized. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2014 and 2013.

The following table presents information about IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2014 and 2013 (in thousands of dollars):

	December 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivatives	$ 506	$ 128	$ —	$ 634	$ 1,437	$ 235	$ —	$ 1,672
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	141	—	—	141	1,153	—	—	1,153
Available-for-sale securities: Equity securities	44,942	—	—	44,942	41,119	—	—	41,119
Liabilities:								
Derivatives	$ 17	$ 3,944	$ —	$ 3,961	$ 546	$ 26	$ —	$ 572

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

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2014 and 2013, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2014		December 31, 2013	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable(1)	$ 3,804	$ 3,804	$ 3,472	$ 3,472
Liabilities:				
Long-term debt(1)	1,615,502	1,788,197	1,616,322	1,600,248
Idaho Power				
Liabilities:				
Long-term debt(1)	$ 1,615,502	$ 1,788,197	$ 1,616,322	$ 1,600,248

(1) Notes receivable and long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16.

Notes receivable are related to Ida-West and are valued based on unobservable inputs, including discounted cash flows, which are partially based on forecasted hydroelectric conditions. Long-term debt is not traded on an exchange and is valued using quoted rates for similar debt in active markets. Carrying values for cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued approximate fair value.

17. SEGMENT INFORMATION

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of Idaho Power. Idaho Power's regulated operations include the generation, transmission, distribution, purchase, and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of Idaho Power that is also subject to regulation and is a 33 percent owner of BCC, an unconsolidated joint venture.

IDACORP's other operating segments are below the quantitative and qualitative thresholds for reportable segments and are included in the "All Other" category in the table below. This category is comprised of IFS's investments in affordable housing developments and historic rehabilitation projects, Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of IESCo, the successor to which wound down its energy marketing operations in 2003, and IDACORP's holding company expenses.

The table below summarizes the segment information for IDACORP's utility operations and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars):

	Utility Operations	All Other	Eliminations	Consolidated Total
2014				
Revenues	$ 1,278,651	$ 3,873	$ —	$ 1,282,524
Operating income	253,437	259	—	253,696
Other income	21,517	37	—	21,554
Interest income	2,705	34	(34)	2,705
Equity-method income	10,814	1,558	—	12,372
Interest expense	79,570	265	(34)	79,801
Income before income taxes	208,903	1,623	—	210,526
Income tax expense (benefit)	19,516	(2,744)	—	16,772
Income attributable to IDACORP, Inc.	189,387	4,093	—	193,480
Total assets	5,620,322	109,044	(12,513)	5,716,853
Expenditures for long-lived assets	273,911	183	—	274,094
2013				
Revenues	$ 1,243,098	$ 3,116	$ —	$ 1,246,214
Operating income	291,691	51	—	291,742
Other income	29,288	152	—	29,440
Interest income	2,426	44	(39)	2,431
Equity-method income	10,242	1,697	—	11,939
Interest expense	80,646	425	(39)	81,032
Income before income taxes	253,001	1,519	—	254,520
Income tax expense (benefit)	76,260	(4,034)	—	72,226
Income attributable to IDACORP, Inc.	176,741	5,676	—	182,417
Total assets	5,266,411	109,541	(11,389)	5,364,563
Expenditures for long-lived assets	235,306	4	—	235,310
2012				
Revenues	$ 1,076,725	$ 3,937	$ —	$ 1,080,662
Operating income	242,179	423	—	242,602
Other income	23,996	368	—	24,364
Interest income	1,980	380	(81)	2,279
Equity-method income	9,412	2,205	—	11,617
Interest expense	73,429	521	(81)	73,869
Income before income taxes	204,138	2,854	—	206,992
Income tax expense (benefit)	35,970	(2,165)	—	33,805
Income attributable to IDACORP, Inc.	168,168	4,846	—	173,014
Total assets	5,215,711	87,522	(11,943)	5,291,290
Expenditures for long-lived assets	239,761	27	—	239,788

18. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's Other income, net and Idaho Power's Other (expense) income, net (in thousands of dollars):

IDACORP - Other income, net	**2014**	**2013**	**2012**
Investment income, net	$ 2,655	$ 2,373	$ 2,280
Carrying charges on regulatory assets	1,949	2,204	1,714
Gain on sale of investments	—	11,637	—
Other income	588	852	409
Life insurance proceeds, net of premiums	1,164	18	14
Other expenses	(28)	(71)	(208)
Total	$ 6,328	$ 17,013	$ 4,209
Idaho Power - Other (expense) income, net			
Investment income, net	$ 2,655	$ 2,369	$ 1,980
Carrying charges on regulatory assets	1,949	2,204	1,714
Gain on sale of investments	—	11,637	—
Other income	551	700	271
SMSP expense	(8,339)	(8,488)	(7,111)
Life insurance proceeds, net of premiums	1,164	18	14
Other expense	(2,343)	(2,668)	(1,850)
Total	$ (4,363)	$ 5,772	$ (4,982)

19. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to the SMSP. The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2014, 2013, and 2012 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Unrealized Gains and Losses on Available-for-Sale Securities	**Defined Benefit Pension Items**	**Total**
December 31, 2014			
Balance at beginning of period	$ —	$ (16,553)	$ (16,553)
Other comprehensive income before reclassifications	—	(9,333)	(9,333)
Amounts reclassified out of AOCI	—	1,728	1,728
Net current-period other comprehensive income	—	(7,605)	(7,605)
Balance at end of period	$ —	$ (24,158)	$ (24,158)
December 31, 2013			
Balance at beginning of period	$ 4,136	$ (21,252)	$ (17,116)
Other comprehensive income before reclassifications	2,951	2,840	5,791
Amounts reclassified out of AOCI	(7,087)	1,859	(5,228)
Net current-period other comprehensive income	(4,136)	4,699	563
Balance at end of period	$ —	$ (16,553)	$ (16,553)
December 31, 2012			
Balance at beginning of period	$ 2,569	$ (14,191)	$ (11,622)
Other comprehensive income before reclassifications	1,567	(8,122)	(6,555)
Amounts reclassified out of AOCI	—	1,061	1,061
Net current-period other comprehensive income	1,567	(7,061)	(5,494)
Balance at end of period	$ 4,136	$ (21,252)	$ (17,116)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2014, 2013, and 2012 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI		
	Year Ended December 31,		
	2014	2013	2012
Unrealized gains on available-for-sale securities			
Realized gain on sale of securities, before tax[1]	$ —	$ (11,637)	$ —
Tax benefit[2]	—	4,550	—
Net of tax	—	(7,087)	—
Amortization of defined benefit pension items[3]			
Prior service cost	220	212	212
Net loss	2,618	2,839	1,530
Total before tax	2,838	3,051	1,742
Tax benefit[2]	(1,110)	(1,192)	(681)
Net of tax	1,728	1,859	1,061
Total reclassification for the period	$ 1,728	$ (5,228)	$ 1,061

(1) The realized gain is included in IDACORP's consolidated income statement in other income, net and in Idaho Power's consolidated income statements in other income (expense), net.
(2) The tax benefit is included in income tax expense (benefit) in the consolidated income statements of both IDACORP and Idaho Power.
(3) Amortization of these items is included in IDACORP's consolidated income statements in other operating expenses and in Idaho Power's consolidated income statements in other expense, net.

20. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $1.4 million in 2014, $1.0 million in 2013, and $0.8 million in 2012.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million to Ida-West in each year from 2012 to 2014.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 19, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 19, 2015

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2014 and 2013 (in thousands of dollars, except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	June 30	September 30	December 31
IDACORP, Inc.				
2014				
Revenues	$ 292,719	$ 317,783	$ 382,201	$ 289,821
Operating income	48,578	71,809	105,722	27,586
Net income	27,185	44,697	87,234	34,638
Net income attributable to IDACORP, Inc.	27,404	44,540	86,889	34,648
Basic earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
Diluted earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
2013				
Revenues	$ 264,928	$ 303,948	$ 381,107	$ 296,230
Operating income	59,433	79,406	115,559	37,343
Net income	35,041	46,639	73,104	27,509
Net income attributable to IDACORP, Inc.	35,194	46,502	73,119	27,602
Basic earnings per share	$ 0.70	$ 0.93	$ 1.46	$ 0.55
Diluted earnings per share	$ 0.70	$ 0.93	$ 1.46	$ 0.55
Idaho Power Company				
2014				
Revenues	$ 292,320	$ 316,655	$ 380,711	$ 288,964
Income from operations	51,949	74,369	107,644	30,129
Net income	27,900	42,653	84,600	34,233
2013				
Revenues	$ 264,368	$ 302,856	$ 380,304	$ 295,569
Income from operations	62,719	81,954	118,215	39,886
Net income	34,046	44,983	70,302	27,411

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures - IDACORP, Inc.

The Chief Executive Officer and Chief Financial Officer of IDACORP, Inc., based on their evaluation of IDACORP, Inc.'s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2014, have concluded that IDACORP, Inc.'s disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - IDACORP, Inc.

Management's Annual Report on Internal Control Over Financial Reporting

The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2014. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)*.

Based on its assessment, management concluded that, as of December 31, 2014, IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2014 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2014.

February 19, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2014 of the Company and our report dated February 19, 2015 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 19, 2015

Disclosure Controls and Procedures - Idaho Power Company

The Chief Executive Officer and Chief Financial Officer of Idaho Power Company, based on their evaluation of Idaho Power Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2014, have concluded that Idaho Power Company's disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - Idaho Power Company

Management's Annual Report on Internal Control Over Financial Reporting

The management of Idaho Power Company (Idaho Power) is responsible for establishing and maintaining adequate internal control over financial reporting of Idaho Power. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Idaho Power's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2014. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)*.

Based on its assessment, management concluded that, as of December 31, 2014, Idaho Power's internal control over financial reporting is effective based on those criteria.

Idaho Power's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2014 and issued a report which appears on the next page and expresses an unqualified opinion on the effectiveness of Idaho Power's internal control over financial reporting as of December 31, 2014.

February 19, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2014, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2014 of the Company and our report dated February 19, 2015 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 19, 2015

Changes in Internal Control Over Financial Reporting - IDACORP, Inc. and Idaho Power Company

There have been no changes in IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "Board of Directors - Committees of the Board of Directors - Audit Committee," "Corporate Governance Principles and Practices - Codes of Business Conduct," and "Corporate Governance Principles and Practices - Certain Relationships and Related Transactions - Related Person Transactions in 2014" to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders are hereby incorporated by reference.

Information regarding IDACORP's executive officers required by this item appears in Item 1 of this report under "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers, and Five-Percent Shareholders" to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2014 with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP) and the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP).

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders[1]	—	$ —	1,182,006 [2]
Equity compensation plans not approved by shareholders	—	$ —	—
Total	—	$ —	1,182,006

[1] Consists of the RSP and the LTICP.

[2] 1,166,210 shares under the LTICP may be issued in connection with stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares, or other equity-based awards as of December 31, 2014. 15,796 shares remain available for future issuance under the RSP and may be issued as restricted stock or performance-based restricted stock. The number of shares listed in this column excludes (i) issued but unvested performance-based restricted shares, and (ii) issued but unvested time-based restricted shares, in both cases issued pursuant to the RSP and LTICP and unvested as of December 31, 2014.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Certain Relationships and Related Transactions" and "Corporate Governance Principles and Practices – Director Independence and Executive Sessions" to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders are hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP: The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2015 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees our principal independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill to Idaho Power for the fiscal years ended December 31, 2014 and 2013:

	2014	2013
Audit fees	$ 1,239,913	$ 1,223,220
Audit-related fees[(1)]	32,300	93,200
Tax fees[(2)]	1,640	54,016
All other fees[(3)]	2,000	2,200
Total	$ 1,275,853	$ 1,372,636

(1) Audits of Idaho Power's benefit plans and compliance audit for the U.S. Department of Energy Smart Grid Investment Grant Program.

(2) Includes fees for benefit plan tax returns and consultation related to tax planning.

(3) Accounting research tool subscription.

Policy on Audit Committee Pre-Approval:

Idaho Power and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, the Audit Committee has established and periodically reviews a pre-approval policy for audit and non-audit services. For 2013 and 2014, all audit and non-audit services and all fees paid in connection with those services were pre-approved by the Audit Committee.

In addition to the audits of Idaho Power's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax, and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include: audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed services; however, the Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to Idaho Power's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee, and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel, and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations, and whether the nature of the engagement and the related fees are consistent with the following principles:

- the independent public accounting firm cannot function in the role of management of Idaho Power; and
- the independent public accounting firm cannot audit its own work.

The pre-approval policy and separate supplements to the pre-approval policy describe the specific audit, audit related, tax, and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of all consolidated financial statements and financial statement schedules.

(3) Exhibits.

Note Regarding Reliance on Statements in Agreements: The agreements filed as exhibits to this Annual Report on Form 10-K are filed to provide information regarding their terms and are not intended to provide any other factual or disclosure information about IDACORP, Inc., Idaho Power Company, or the other parties to the agreements. Some of the agreements contain statements, representations, and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (a) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate; (b) have been qualified by disclosures that were made to the other party, which disclosures are not necessarily reflected in the agreement; (c) may apply standards of materiality in a way that is different from what may be viewed as material to investors; and (d) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, readers should not rely upon the statements, representations, or warranties made in the agreements.

		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
2	Agreement and Plan of Exchange between IDACORP, Inc. and Idaho Power Company, dated as of February 2, 1998	S-4	333-48031	A	3/16/1998	
3.1	Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on June 30, 1989	S-3 Post-Effective Amend. No. 2	33-00440	4(a)(xiii)	6/30/1989	
3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on November 5, 1991	S-3	33-65720	4(a)(ii)	7/7/1993	
3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on June 30, 1993	S-3	33-65720	4(a)(iii)	7/7/1993	
3.4	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998	S-8 Post-Effective Amend. No. 1	33-56071-9 9	3(d)	10/1/1998	
3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000	10-Q	1-3198	3(a)(iii)	8/4/2000	
3.6	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005	8-K	1-3198	3.3	1/26/2005	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
3.7	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007	8-K	1-3198	3.3	11/19/2007	
3.8	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-3198	3.14	5/21/2012	
3.9	Amended Bylaws of Idaho Power Company, amended on November 15, 2007 and presently in effect	8-K	1-3198	3.2	11/19/2007	
3.10	Articles of Incorporation of IDACORP, Inc.	S-3	333-64737	3.1	11/4/1998	
3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998	S-3 Amend. No. 1	333-64737	3.2	11/4/1998	
3.12	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998	S-3 Post-Effective Amend. No. 1	333-00139-99	3(b)	9/22/1998	
3.13	Articles of Amendment to Articles of Incorporation of IDACORP, Inc., as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-14465	3.13	5/21/2012	
3.14	Amended and Restated Bylaws of IDACORP, Inc., amended on October 29, 2014 and presently in effect	10-Q	1-14465	3.15	10/30/2014	
4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees		2-3413	B-2		
4.2	Idaho Power Company Supplemental Indentures to Mortgage and Deed of Trust:					
	File number 1-MD, as Exhibit B-2-a, First, July 1, 1939					
	File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943					
	File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947					
	File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948					
	File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949					
	File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951					
	File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957					
	File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957					
	File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957					
	File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958					
	File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958					
	File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959					
	File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960					
	File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961					
	File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964					
	File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966					
	File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966					
	File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972					
	File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974					
	File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974					
	File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974					
	File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976					
	File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978					
	File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979					
	File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981					
	File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982					
	File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986					
	File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989					

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
	File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990					
	File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991					
	File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991					
	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992					
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993					
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993					
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000					
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001					
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003					
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003					
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iv), Thirty-ninth, October 1, 2003					
	File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005					
	File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006					
	File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007					
	File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007					
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008					
	File number 1-3198, Form 10-K filed on 2/23/10, as Exhibit 4.10, Forty-fifth, February 1, 2010					
	File number 1-3198, Form 8-K filed on 6/18/10, as Exhibit 4, Forty-sixth, June 1, 2010					
	File number 1-3198, Form 8-K filed on 7/12/2013, as Exhibit 4.1, Forty-seventh, July 1, 2013					
4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.4)	10-Q	1-3198	4(b)	8/4/2000	
4.4	Agreement of Idaho Power Company to furnish certain debt instruments	S-3	33-65720	4(f)	7/7/1993	
4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments	10-Q	1-14465	4(c)(ii)	11/6/2003	
4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation	S-3 Post-Effective Amend. No. 2	33-00440	2(a)(iii)	6/30/1989	
4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.1	2/28/2001	
4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.2	2/28/2001	
4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	S-3	333-67748	4.13	8/16/2001	
4.10	Idaho Power Company Instrument of Further Assurance relating to Mortgage and Deed of Trust, dated as of August 3, 2010	10-Q	1-3198	4.12	8/5/2010	
10.1	Agreements, dated September 22, 1969, between Idaho Power Company and Pacific Power & Light Company, relating to the operation, construction, and ownership of the Jim Bridger Project (see Exhibits 10.4 and 10.5)		2-49584	5(b)		
10.2	Amendment, dated February 1, 1974, relating to the agreement filed as Exhibit 10.1 (see Exhibits 10.4 and 10.5)		2-51762	5(c)		
10.3	Agreement, dated as of October 11, 1973, between Idaho Power Company and Pacific Power & Light Company		2-49584	5(c)		

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.4	Amended and Restated Agreement for the Operation of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp (to supersede Exhibits 10.1 and 10.2 upon satisfaction of conditions precedent in the agreement)					X
10.5	Amended and Restated Agreement for the Ownership of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp (to supersede Exhibits 10.1 and 10.2 upon satisfaction of conditions precedent in the agreement)					X
10.6	Guaranty Agreement, dated April 11, 2000, between Idaho Power Company and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho	10-Q	1-3198	10(c)	8/4/2000	
10.7	Guaranty Agreement, dated as of August 30, 1974, between Idaho Power Company and Pacific Power & Light Company	S-7	2-62034	5(r)	6/30/1978	
10.8	Letter Agreement, dated January 23, 1976, between Idaho Power Company and Portland General Electric Company		2-56513	5(i)		
10.9	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and Idaho Power Company	S-7	2-62034	5(s)	6/30/1978	
10.10	Amendment, dated September 30, 1977, relating to the agreement filed as Exhibit 10.8	S-7	2-62034	5(t)	6/30/1978	
10.11	Amendment, dated October 31, 1977, relating to the agreement filed as Exhibit 10.8	S-7	2-62034	5(u)	6/30/1978	
10.12	Amendment, dated January 23, 1978, relating to the agreement filed as Exhibit 10.8	S-7	2-62034	5(v)	6/30/1978	
10.13	Amendment, dated February 15, 1978, relating to the agreement filed as Exhibit 10.8	S-7	2-62034	5(w)	6/30/1978	
10.14	Amendment, dated September 1, 1979, relating to the agreement filed as Exhibit 10.8	S-7	2-68574	5(x)	7/23/1980	
10.15	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir	S-7	2-68574	5(z)	7/23/1980	
10.16	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and Idaho Power Company	S-7	2-64910	5(y)	6/29/1979	
10.17	Framework Agreement, dated October 1, 1984, between the State of Idaho and Idaho Power Company relating to Idaho Power Company's Swan Falls and Snake River water rights	S-3	33-65720	10(h)	7/7/1993	
10.18	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.17	S-3	33-65720	10(h)(i)	7/7/1993	
10.19	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.17	S-3	33-65720	10(h)(ii)	7/7/1993	
10.20	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.17	10-Q	1-14465	10.58	5/7/2009	
10.21	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between Idaho Power Company and the Twin Falls Canal Company and the Northside Canal Company Limited	S-3	33-65720	10(m)	7/7/1993	
10.22	Hemingway Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp (to be superseded by the agreement filed as Exhibit 10.24 upon satisfaction of conditions precedent in that agreement)	10-Q	1-14465, 1-3198	10.70	8/5/2010	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.23	Populus Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp (to be superseded by the agreement filed as Exhibit 10.24 upon satisfaction of conditions precedent in that agreement)	10-Q	1-14465, 1-3198	10.71	8/5/2010	
10.24	Joint Ownership and Operating Agreement, dated October 24, 2014, between Idaho Power Company and PacifiCorp (to supersede Exhibits 10.22 and 10.23 upon satisfaction of conditions precedent in the agreement)	8-K	1-14465, 1-3198	10.1	10/24/2014	
10.25[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008	10-K	1-14465, 1-3198	10.15	2/26/2009	
10.26[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees I	10-Q	1-14465, 1-3198	10.62	11/1/2012	
10.27[1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 30, 2011	10-K	1-14465, 1-3198	10.21	2/22/2012	
10.28[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees II	10-Q	1-14465, 1-3198	10.63	11/1/2012	
10.29[1]	Amendment, dated January 16, 2014, to the Idaho Power Company Security Plan for Senior Management Employees II	10-K	1-14465, 1-3198	10.26	2/20/2014	
10.30[1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007	10-Q	1-14465, 1-3198	10(h)(iii)	10/31/2007	
10.31[1]	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting)	10-Q	1-14465, 1-3198	10(h)(vi)	11/2/2006	
10.32[1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting)	10-Q	1-14465, 1-3198	10(h) (vii)	11/2/2006	
10.33[1]	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006	10-Q	1-14465, 1-3198	10(h) (viii)	11/2/2006	
10.34[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2014					X
10.35[1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xix)	11/2/2006	
10.36[1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xx)	11/2/2006	
10.37[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (senior vice president and higher), approved November 20, 2008	10-K	1-14465, 1-3198	10.24	2/26/2009	
10.38[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (below senior vice president), approved November 20, 2008	10-K	1-14465, 1-3198	10.25	2/26/2009	
10.39[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, approved March 17, 2010	8-K	1-14465, 1-3198	10.1	3/24/2010	
10.40[1]	IDACORP, Inc. and/or Idaho Power Company Officers with Amended and Restated Change in Control Agreements chart, as of January 1, 2015					X
10.41[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 18, 2010	10-K	1-14465, 1-3198	10.33	2/23/2011	
10.42[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement	10-Q	1-14465, 1-3198	10(h) (xvi)	11/2/2006	
10.43[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting)					X
10.44[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals)					X

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.45[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting)	10-Q	1-14465, 1-3198	10(h)(xvii)	11/2/2006	
10.46[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals)	10-Q	1-14465, 1-3198	10.69	5/5/2011	
10.47[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated January 16, 2014	10-K	1-14465, 1-3198	10.42	2/20/2014	
10.48[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008	10-K	1-14465, 1-3198	10.32	2/26/2009	
10.49[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2015					X
10.50[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, as of January 16, 2014 (superseded by Exhibit 10.49 effective January 1, 2015)	10-K	1-14465, 1-3198	10.44	2/20/2014	
10.51[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.46	2/26/2009	
10.52[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.47	2/26/2009	
10.53[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.48	2/26/2009	
10.54[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.49	2/26/2009	
10.55[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.50	2/26/2009	
10.56[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.51	2/26/2009	
10.57[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.52	2/26/2009	
10.58[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.53	2/26/2009	
10.59[1]	Idaho Power Company Employee Savings Plan, as amended and restated as of January 1, 2010	10-K	1-14465, 1-3198	10.63	2/23/2010	
10.60[1]	Amendment to the Idaho Power Company Employee Savings Plan, dated August 31, 2011	10-Q	1-14465, 1-3198	10.72	11/3/2011	
10.61[1]	Amendment to the Idaho Power Company Employee Savings Plan, dated November 29, 2011	10-Q	1-14465, 1-3198	10.61	8/2/2012	
10.62[1]	Third Amendment to the Idaho Power Company Employee Savings Plan, dated October 11, 2013	10-Q	1-14465, 1-3198	10.64	11/5/2013	
10.63[1]	Fourth Amendment to the Idaho Power Company Employee Savings Plan, dated June 16, 2014	10-Q	1-14465, 1-3198	10.65	7/31/2014	
10.64	Second Amended and Restated Credit Agreement, dated October 26, 2011, among IDACORP, Inc., various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners	8-K	1-14465	10.70	10/28/2011	
10.65	First Extension Agreement, dated October 12, 2012, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.63	10-Q	1-14465	10.64	11/1/2012	
10.66	Second Extension Agreement, dated October 8, 2013, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.63	10-Q	1-14465	10.62	11/5/2013	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.67	Second Amended and Restated Credit Agreement, dated October 26, 2011, among Idaho Power Company, various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners	8-K	1-3198	10.71	10/28/2011	
10.68	First Extension Agreement, dated October 12, 2012, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.66	10-Q	1-3198	10.65	11/1/2012	
10.69	Second Extension Agreement, dated October 8, 2013, to the Second Amended and Restated Credit Agreement, dated October 26, 2011, filed as Exhibit 10.66	10-Q	1-3198	10.63	11/5/2013	
10.70	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.71	Guaranty Agreement, dated February 10, 1992, between Idaho Power Company and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc.	S-3	33-65720	10(m)(i)	7/7/1993	
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
21.1	Subsidiaries of IDACORP, Inc.	10-K	1-14465, 1-3198	21.1	2/21/2013	
23.1	Consent of Registered Independent Accounting Firm					X
23.2	Consent of Registered Independent Accounting Firm					X
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification					X
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification					X
31.3	Idaho Power Rule 13a-14(a) CEO certification					X
31.4	Idaho Power Rule 13a-14(a) CFO certification					X
32.1	IDACORP, Inc. Section 1350 CEO certification					X
32.2	IDACORP, Inc. Section 1350 CFO certification					X
32.3	Idaho Power Section 1350 CEO certification					X
32.4	Idaho Power Section 1350 CFO certification					X
95.1	Mine Safety Disclosures					X
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X

[1] Management contract or compensatory plan or arrangement

IDACORP, INC.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 193,707	$ 182,463	$ 172,844
Investment income	—	3	295
Total income	193,707	182,466	173,139
Expenses:			
Operating expenses	1,376	940	473
Interest expense	261	416	511
Other expenses	45	71	45
Total expenses	1,682	1,427	1,029
Income from Before Income Taxes	192,025	181,039	172,110
Income Tax Benefit	(1,455)	(1,378)	(904)
Net Income Attributable to IDACORP, Inc.	193,480	182,417	173,014
Other comprehensive (income) loss	(7,605)	563	(5,494)
Comprehensive Income Attributable to IDACORP, Inc.	$ 185,875	$ 182,980	$ 167,520

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2014	2013	2012
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 109,289	$ 96,391	$ 61,876
Investing Activities:			
Distributions from (contributions to) subsidiaries	—	2,282	(7,525)
Net cash provided by (used in) investing activities	—	2,282	(7,525)
Financing Activities:			
Issuance of common stock	195	255	4,882
Dividends on common stock	(88,489)	(78,832)	(68,928)
(Decrease) increase in short-term borrowings	(23,450)	(14,950)	15,500
Change in intercompany notes payable	(198)	647	(2,308)
Other	(469)	(431)	(3,147)
Net cash used in financing activities	(112,411)	(93,311)	(54,001)
Net (decrease) increase in cash and cash equivalents	(3,122)	5,362	350
Cash and cash equivalents at beginning of year	8,898	3,536	3,186
Cash and cash equivalents at end of year	$ 5,776	$ 8,898	$ 3,536

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,	
	2014	2013
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 5,776	$ 8,898
Receivables	1,702	996
Income taxes receivable	—	2,044
Deferred income taxes	42,766	33,928
Other	106	117
Total current assets	50,350	45,983
Investment in subsidiaries	1,910,084	1,814,565
Other Assets:		
Deferred income taxes	44,546	56,718
Other	287	385
Total other assets	44,833	57,103
Total assets	$ 2,005,267	$ 1,917,651
Liabilities and Shareholders' Equity		
Current Liabilities:		
Notes payable	$ 31,300	$ 54,750
Accounts payable	8	4
Taxes accrued	8,950	—
Other	854	684
Total current liabilities	41,112	55,438
Other Liabilities:		
Intercompany notes payable	9,658	9,822
Other	1,296	1,742
Total other liabilities	10,954	11,564
IDACORP, Inc. Shareholders' Equity	1,953,201	1,850,649
Total Liabilities and Shareholders' Equity	$ 2,005,267	$ 1,917,651

The accompanying note is an integral part of these statements.

NOTE TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2014 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries: IDACORP has accounted for the earnings of its subsidiaries under the equity method of accounting in these unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends that IDACORP subsidiaries paid to IDACORP of $91 million in 2014 and 2013, and $71 million in 2012.

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2014, 2013, and 2012

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Reserve for uncollectible notes	885	(333)	—	—	552
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Reserve for uncollectible notes	1,260	(375)	—	—	885
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671
2012:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,435	$ 4,524	$ 283	$ 4,369	$ 1,873
Reserve for uncollectible notes	2,743	(1,483)	—	—	1,260
Other Reserves:					
Injuries and damages	1,925	4,481	—	926	5,480

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, and notes reserves, includes reversals of amounts previously written off.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2014, 2013, and 2012

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671
2012:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,435	$ 4,524	$ 283	$ 4,369	$ 1,873
Other Reserves:					
Injuries and damages	1,925	4,481	—	926	5,480

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, includes reversals of amounts previously written off.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 19, 2015 Date		IDACORP, INC.
	By:	*/s/ Darrel T. Anderson* Darrel T. Anderson President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 19, 2015
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 19, 2015
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 19, 2015
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 19, 2015
/s/ Thomas Carlile Thomas Carlile	Director	February 19, 2015
/s/ Richard J. Dahl Richard J. Dahl	Director	February 19, 2015
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 19, 2015
/s/ Judith A. Johansen Judith A. Johansen	Director	February 19, 2015
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 19, 2015
/s/ J. LaMont Keen J. LaMont Keen	Director	February 19, 2015
/s/ Christine King Christine King	Director	February 19, 2015
/s/ Richard J. Navarro Richard J. Navarro	Director	February 19, 2015
/s/ Jan B. Packwood Jan B. Packwood	Director	February 19, 2015
/s/ Joan H. Smith Joan H. Smith	Director	February 19, 2015
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 19, 2015

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 19, 2015 — Idaho Power Company

Date

By: */s/ Darrel T. Anderson*

Darrel T. Anderson

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 19, 2015
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 19, 2015
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 19, 2015
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 19, 2015
/s/ Thomas Carlile Thomas Carlile	Director	February 19, 2015
/s/ Richard J. Dahl Richard J. Dahl	Director	February 19, 2015
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 19, 2015
/s/ Judith A. Johansen Judith A. Johansen	Director	February 19, 2015
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 19, 2015
/s/ J. LaMont Keen J. LaMont Keen	Director	February 19, 2015
/s/ Christine King Christine King	Director	February 19, 2015
/s/ Richard J. Navarro Richard J. Navarro	Director	February 19, 2015
/s/ Jan B. Packwood Jan B. Packwood	Director	February 19, 2015
/s/ Joan H. Smith Joan H. Smith	Director	February 19, 2015
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 19, 2015

EXHIBIT INDEX

Exhibit No.	Description
10.4	Amended and Restated Agreement for the Operation of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp (to supersede Exhibits 10.1 and 10.2 upon satisfaction of conditions precedent in the agreement)
10.5	Amended and Restated Agreement for the Ownership of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp (to supersede Exhibits 10.1 and 10.2 upon satisfaction of conditions precedent in the agreement)
10.34[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 20, 2014
10.40[1]	IDACORP, Inc. and/or Idaho Power Company Officers with Amended and Restated Change in Control Agreements chart, as of January 1, 2015
10.43[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting)
10.44[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals)
10.49[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2015
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of Independent Registered Public Accounting Firm
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification
31.3	Idaho Power Rule 13a-14(a) CEO certification
31.4	Idaho Power Rule 13a-14(a) CFO certification
32.1	IDACORP, Inc. Section 1350 CEO certification
32.2	IDACORP, Inc. Section 1350 CFO certification
32.3	Idaho Power Section 1350 CEO certification
32.4	Idaho Power Section 1350 CFO certification
95.1	Mine safety disclosures
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

[1] Management contract or compensatory plan or arrangement.

Boise River and foothills

IDACORP, Inc.—Boise, Idaho-based and formed in 1998—is a holding company comprised of Idaho Power Company, a regulated electric utility; IDACORP Financial, a holder of affordable housing projects and other real estate investments; and Ida-West Energy, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. IDACORP's origins lie with Idaho Power and operations beginning in 1916. Today, Idaho Power employs approximately 2,000 people to serve a 24,000-square-mile service area in southern Idaho and eastern Oregon. With 17 low-cost hydroelectric projects as the core of its generation portfolio, Idaho Power's more than 500,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about Idaho Power or IDACORP, Inc., visit www.idahopower.com or www.idacorpinc.com.

Front cover photo: Idaho Power's Shoshone Falls Power Plant stands below the mighty falls.

Forward-Looking Statements: Please refer to IDACORP's and Idaho Power's Form 10-K for a description of the risks and uncertainties related to the forward-looking statements included in this Annual Report.

For your reference

Dividend Payment Dates

IDACORP, Inc. Common Stock dividends are paid quarterly on or about the 28th of February, and the 30th of May, August and November.

Transfer Agent/Registrar

For IDACORP, Inc. Common Stock
Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
1-800-565-7890

Common Stock Information

Ticker symbol: IDA
Listed: New York Stock Exchange, 20 Broad St.
New York, New York 10005

Contact

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Email: lspencer@idacorpinc.com

Shareowner Contact: Colette Shepard
Phone: 1-800-635-5406 Fax: 208-388-6955
Email: cshepard@idacorpinc.com

Corporate Headquarters

Mailing: P.O. Box 70, Boise, Idaho 83707-0070
Street: 1221 W. Idaho St., Boise, Idaho 83702-5627
Phone: 208-388-2200
Website: www.idacorpinc.com

SEC Form 10-K

The IDACORP, Inc. and Idaho Power Company combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders also are available on our website at www.idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

2015 Annual Meeting

The 2015 Annual Meeting of Shareholders will be held at Idaho Power's Corporate Headquarters, 1221 W. Idaho St., Boise, Idaho at 10 a.m. local time on Thursday, May 21, 2015. Formal notice of the meeting will be mailed to shareholders on or about Wednesday, April 3, 2015.

IDACORP®

P.O. Box 70
Boise, ID 83707-0070

www.idacorpinc.com