e-FILING REPORT COVER SHEET

REPORT NAME: 2017 FERC Form 1 and 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 27, 2018

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Idaho Power Company's 2017 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, 2017. Also included is the IDACORP 2017 Annual Report.

If you have any questions, please contact Regulatory Analyst 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 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

# 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 2017/Q4 |

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

# 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 2017/Q4 |

Deloitte.

**Deloitte & Touche LLP**
800 West Main Street
Suite 1400
Boise, ID 83702-7734
USA

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

## INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the accompanying financial statements of Idaho Power Company (the "Company"), which comprise the balance sheet - regulatory basis as of December 31, 2017, and the related statements of income - regulatory basis, retained earnings - regulatory basis, and cash flows - regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

### Management's Responsibility for the Financial Statements

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

### Auditors' Responsibility

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

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

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

**Opinion**

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Idaho Power Company as of December 31, 2017, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

**Basis of Accounting**

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

**Restricted Use**

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

Deloitte & Touche LLP

April 18, 2018

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

**IDENTIFICATION**

| | |
|---|---|
| 01 Exact Legal Name of Respondent<br>Idaho Power Company | 02 Year/Period of Report<br>End of 2017/Q4 |
| 03 Previous Name and Date of Change *(if name changed during year)* | / / |
| 04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*<br>1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070 | |
| 05 Name of Contact Person<br>Ken Petersen | 06 Title of Contact Person<br>VP, Controller and CAO |
| 07 Address of Contact Person *(Street, City, State, Zip Code)*<br>1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070 | |

| | | |
|---|---|---|
| 08 Telephone of Contact Person, *Including Area Code*<br>(208) 388-2761 | 09 This Report Is<br>(1) [X] An Original (2) [ ] A Resubmission | 10 Date of Report *(Mo, Da, Yr)*<br>04/18/2018 |

**ANNUAL CORPORATE OFFICER CERTIFICATION**

The undersigned officer certifies that:

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

| | | |
|---|---|---|
| 01 Name<br>Ken Petersen<br>02 Title<br>Vice President, Controller & CAO | 03 Signature<br>Ken Petersen | 04 Date Signed *(Mo, Da, Yr)*<br>04/18/2018 |

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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:

- [ ] 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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

## CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

## 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 800,000 |
| 3 | | | |
| 4 | Senior Vice President, CFO & Treasurer | Steven Keen | 420,000 |
| 5 | | | |
| 6 | Senior Vice President, COO | Lisa Grow | 400,000 |
| 7 | | | |
| 8 | Senior Vice President, Public Affairs | Jeffrey Malmen | 295,000 |
| 9 | | | |
| 10 | Senior Vice President, Admin Services & Chief HR Officer | Lonnie Krawl | 300,000 |
| 11 | | | |
| 12 | Senior Vice President & General Counsel | Brian Buckham | 300,000 |
| 13 | | | |
| 14 | Vice President, T&D Engineering & Construction, and CSO | Vern Porter | 295,000 |
| 15 | | | |
| 16 | Vice President, Power Supply | Tessia Park | 265,000 |
| 17 | | | |
| 18 | Vice President, Customer Operations & Bus. Development | Adam Richins | 220,000 |
| 19 | | | |
| 20 | Vice President, Corporate Controller & CAO | Ken Petersen | 255,000 |
| 21 | | | |
| 22 | Vice President of Information Technology & CIO | Jeff Glenn | 240,000 |
| 23 | | | |
| 24 | Vice President of Regulatory Affairs | Tim Tatum | 180,000 |
| 25 | | | |
| 26 | Corporate Secretary | Patrick Harrington | 202,000 |
| 27 | | | |
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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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | Principal Business Address<br>(b) |
|---|---|---|
| 1 | | |
| 2 | Judith A. Johansen | 10446 E. Palo Brea Dr., Scottsdale, Arizona 85262 |
| 3 | | |
| 4 | Christine King, Comp. Committee Chair,*** | 8527 East Old Field Rd |
| 5 | | Scottsdale, Arizona 85266 |
| 6 | | |
| 7 | Thomas E. Carlile | 2719 North Woodview place, Boise Idaho 83702 |
| 8 | | |
| 9 | Darrel T. Anderson President & CEO, ** *** | Idaho Power Company, 1221 W. Idaho Street, |
| 10 | | P.O. Box 70, Boise, Idaho 83707-0070 |
| 11 | | |
| 12 | J. LaMont Keen | 481 North Strata Via Way, Boise Idaho 83712 |
| 13 | | |
| 14 | Robert A. Tinstman, Board Chair & Corp Gov Chair, *** | 4433 W. Quail Point Court, Boise, Idaho 83703 |
| 15 | | |
| 16 | Richard Dahl, Audit Chair *** | 60 Laiki Pl. |
| 17 | | Kailua, Hawaii 96734-1905 |
| 18 | | |
| 19 | Dennis L. Johnson | 926 W Oakhampton Dr, Eagle, Idaho 83616 |
| 20 | | |
| 21 | Ronald W. Jibson | 417 Aerie Circle, North Salt Lake City, Utah 84054 |
| 22 | | |
| 23 | Richard J. Navarro | 1256 E. Candleridge Ct., Boise, Idaho 83712 |
| 24 | | |
| 25 | Annette G. Elg (1) | 3475 E. Rivernest Lane, Boise, Idaho 83706-6928 |
| 26 | | |
| 27 | (1) Appointed to Board February 2017 | |
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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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 20170828-5100 | 08/28/2017 | ER09-1641-000 | Idaho Power Company | FERC Electric Tariff |
| 2 | | | | 2017 Annual | |
| 3 | | | | Informational Filling | |
| 4 | | | | under ER09-1641-000 | |
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## INFORMATION ON FORMULA RATES
### Formula Rate Variances

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

| Line No. | Page No(s). | Schedule | Column | Line No |
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| Name of Respondent | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. None

6. None

7. None

8. Effective 12/30/2017 a 3.0% general wage adjustment was implemented.

9. Disclosed in Financial Statement footnotes, see page 123.27.

10. None

11. None

12. None

13. Officer Changes in 2017

    - Lisa A. Grow's title changed from "Sr. Vice President of Operations" to "Sr. Vice President and Chief Operating Officer" effective March 1, 2017.
    - N. Vern Porter's title changed from "Vice President of Customer Operations" to "Vice President of Transmission and Distribution Engineering and Construction and Chief Safety Officer" effective March 1, 2017.
    - Adam J. Richins was appointed "Vice President of Customer Operations and Business Development" effective March 1, 2017.

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 5,914,236,887 | 5,739,484,446 |
| 3 | Construction Work in Progress (107) | 200-201 | 452,424,340 | 405,068,524 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 6,366,661,227 | 6,144,552,970 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 2,283,266,546 | 2,175,085,495 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 4,083,394,681 | 3,969,467,475 |
| 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) | | 4,083,394,681 | 3,969,467,475 |
| 15 | Utility Plant Adjustments (116) | | 0 | 0 |
| 16 | Gas Stored Underground - Noncurrent (117) | | 0 | 0 |
| 17 | **OTHER PROPERTY AND INVESTMENTS** | | | |
| 18 | Nonutility Property (121) | | 1,071,638 | 1,071,638 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 0 | 0 |
| 20 | Investments in Associated Companies (123) | | 0 | 0 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 72,212,978 | 77,130,927 |
| 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) | | 0 | 0 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 30,265,777 | 24,018,570 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 4,074 | 0 |
| 31 | Long-Term Portion of Derivative Assets – Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 103,554,467 | 102,221,135 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 34,375,147 | 14,159,468 |
| 36 | Special Deposits (132-134) | | 2,364,499 | 1,168,084 |
| 37 | Working Fund (135) | | 10,500 | 13,600 |
| 38 | Temporary Cash Investments (136) | | 10,260,000 | 29,967,367 |
| 39 | Notes Receivable (141) | | -86,399 | -83,038 |
| 40 | Customer Accounts Receivable (142) | | 77,764,379 | 73,276,818 |
| 41 | Other Accounts Receivable (143) | | 28,169,330 | 25,535,458 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 2,192,252 | 1,131,759 |
| 43 | Notes Receivable from Associated Companies (145) | | 0 | 0 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 0 | 0 |
| 45 | Fuel Stock (151) | 227 | 56,638,459 | 53,700,442 |
| 46 | Fuel Stock Expenses Undistributed (152) | 227 | 5 | -2,623 |
| 47 | Residuals (Elec) and Extracted Products (153) | 227 | 0 | 0 |
| 48 | Plant Materials and Operating Supplies (154) | 227 | 53,856,630 | 54,454,684 |
| 49 | Merchandise (155) | 227 | 0 | 0 |
| 50 | Other Materials and Supplies (156) | 227 | 0 | 0 |
| 51 | Nuclear Materials Held for Sale (157) | 202-203/227 | 0 | 0 |
| 52 | Allowances (158.1 and 158.2) | 228-229 | 0 | 0 |
| | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 53 | (Less) Noncurrent Portion of Allowances | | 0 | 0 |
| 54 | Stores Expense Undistributed (163) | 227 | 1,888,307 | 3,403,797 |
| 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) | | 16,865,877 | 18,269,814 |
| 58 | Advances for Gas (166-167) | | 0 | 0 |
| 59 | Interest and Dividends Receivable (171) | | 6,500 | 24,539 |
| 60 | Rents Receivable (172) | | 0 | 0 |
| 61 | Accrued Utility Revenues (173) | | 75,119,761 | 80,738,420 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 0 | 0 |
| 63 | Derivative Instrument Assets (175) | | 22,228 | 5,951,233 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 4,074 | 0 |
| 65 | Derivative Instrument Assets - Hedges (176) | | 0 | 0 |
| 66 | (Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176 | | 0 | 0 |
| 67 | Total Current and Accrued Assets (Lines 34 through 66) | | 355,058,897 | 359,446,304 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 15,097,172 | 16,313,567 |
| 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 | 1,132,096,194 | 1,471,940,401 |
| 73 | Prelim. Survey and Investigation Charges (Electric) (183) | | 0 | 0 |
| 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) | | 535,559 | 1,290,608 |
| 77 | Temporary Facilities (185) | | 0 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 73,132,688 | 75,332,657 |
| 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) | | 39,822,616 | 41,975,568 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 289,813,919 | 286,326,529 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 0 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 1,550,498,148 | 1,893,179,330 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 6,092,506,193 | 6,324,314,244 |

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | end of 2017/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 | 1,234,859,727 | 1,136,879,473 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | 69,749,884 | 74,667,833 |
| 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) | -26,872,209 | -20,881,620 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 2,085,774,942 | 1,998,703,226 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 1,745,460,000 | 1,745,460,000 |
| 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 | 19,885,000 | 20,948,636 |
| 22 | Unamortized Premium on Long-Term Debt (225) | | 0 | 0 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 4,124,868 | 4,417,463 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 1,761,220,132 | 1,761,991,173 |
| 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) | | 1,468,935 | 1,792,128 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 438,886,025 | 411,633,628 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 0 | 0 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 119,666,875 | 103,219,162 |
| 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) | | 26,415,381 | 26,257,286 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 586,437,216 | 542,902,204 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 0 | 21,800,000 |
| 38 | Accounts Payable (232) | | 107,891,859 | 126,470,087 |
| 39 | Notes Payable to Associated Companies (233) | | 4,083,304 | 244,435 |
| 40 | Accounts Payable to Associated Companies (234) | | 57,561,953 | 1,056,374 |
| 41 | Customer Deposits (235) | | 2,037,068 | 2,864,762 |
| 42 | Taxes Accrued (236) | 262-263 | -15,156,342 | -11,945,257 |
| 43 | Interest Accrued (237) | | 22,620,139 | 22,539,658 |
| 44 | Dividends Declared (238) | | 0 | 0 |
| 45 | Matured Long-Term Debt (239) | | 0 | 0 |

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

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 46 | Matured Interest (240) | | 0 | 0 |
| 47 | Tax Collections Payable (241) | | 2,751,894 | 2,847,908 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 50,874,603 | 49,816,656 |
| 49 | Obligations Under Capital Leases-Current (243) | | 0 | 0 |
| 50 | Derivative Instrument Liabilities (244) | | 1,224,571 | 0 |
| 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) | | 233,889,049 | 215,694,623 |
| 55 | DEFERRED CREDITS | | | |
| 56 | Customer Advances for Construction (252) | | 6,762,256 | 5,252,737 |
| 57 | Accumulated Deferred Investment Tax Credits (255) | 266-267 | 87,384,738 | 79,959,845 |
| 58 | Deferred Gains from Disposition of Utility Plant (256) | | 0 | 0 |
| 59 | Other Deferred Credits (253) | 269 | 8,746,270 | 10,479,342 |
| 60 | Other Regulatory Liabilities (254) | 278 | 307,404,206 | 77,043,013 |
| 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) | | 890,330,923 | 1,449,526,847 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 124,556,461 | 182,761,234 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 1,425,184,854 | 1,805,023,018 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 6,092,506,193 | 6,324,314,244 |

## 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 | 1,340,860,404 | 1,255,298,799 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 769,799,625 | 734,428,076 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 60,983,589 | 67,074,765 | | |
| 6 | Depreciation Expense (403) | 336-337 | 153,958,586 | 135,048,584 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | 566,665 | 720,272 | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 6,243,722 | 6,649,455 | | |
| 9 | Amort. of Utility Plant Acq. Adj. (406) | 336-337 | 32,539 | | | |
| 10 | Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407) | | | | | |
| 11 | Amort. of Conversion Expenses (407) | | | | | |
| 12 | Regulatory Debits (407.3) | | 1,289,770 | 1,242,422 | | |
| 13 | (Less) Regulatory Credits (407.4) | | -788,738 | | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 34,089,536 | 32,823,311 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | 44,701,501 | -96,137 | | |
| 16 | - Other (409.1) | 262-263 | 10,557,960 | 3,659,280 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 54,908,265 | 58,087,034 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 80,542,460 | 26,177,294 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | 7,424,893 | 304,915 | | |
| 20 | (Less) Gains from Disp. of Utility Plant (411.6) | | | | | |
| 21 | Losses from Disp. of Utility Plant (411.7) | | | | | |
| 22 | (Less) Gains from Disposition of Allowances (411.8) | | 130,740 | 49,266 | | |
| 23 | Losses from Disposition of Allowances (411.9) | | | | | |
| 24 | Accretion Expense (411.10) | | 221,929 | 231,983 | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24) | | 1,064,894,118 | 1,013,947,400 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 275,966,286 | 241,351,399 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 |
| 1,340,860,404 | 1,255,298,799 | | | | | 2 |
| | | | | | | 3 |
| 769,799,625 | 734,428,076 | | | | | 4 |
| 60,983,589 | 67,074,765 | | | | | 5 |
| 153,958,586 | 135,048,584 | | | | | 6 |
| 566,665 | 720,272 | | | | | 7 |
| 6,243,722 | 6,649,455 | | | | | 8 |
| 32,539 | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| 1,289,770 | 1,242,422 | | | | | 12 |
| -788,738 | | | | | | 13 |
| 34,089,536 | 32,823,311 | | | | | 14 |
| 44,701,501 | -96,137 | | | | | 15 |
| 10,557,960 | 3,659,280 | | | | | 16 |
| 54,908,265 | 58,087,034 | | | | | 17 |
| 80,542,460 | 26,177,294 | | | | | 18 |
| 7,424,893 | 304,915 | | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| 130,740 | 49,266 | | | | | 22 |
| | | | | | | 23 |
| 221,929 | 231,983 | | | | | 24 |
| 1,064,894,118 | 1,013,947,400 | | | | | 25 |
| 275,966,286 | 241,351,399 | | | | | 26 |

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| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account<br>(a) | (Ref.)<br>Page No.<br>(b) | TOTAL<br>Current Year<br>(c) | TOTAL<br>Previous Year<br>(d) | Current 3 Months Ended<br>Quarterly Only<br>No 4th Quarter<br>(e) | Prior 3 Months Ended<br>Quarterly Only<br>No 4th Quarter<br>(f) |
|---|---|---|---|---|---|---|
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 275,966,286 | 241,351,399 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | 4,032,474 | 4,054,219 | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | 4,104,918 | 3,886,708 | | |
| 33 | Revenues From Nonutility Operations (417) | | 28,462 | 31,177 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 61,905 | 97,371 | | |
| 35 | Nonoperating Rental Income (418) | | -7,437 | -4,136 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | 7,082,051 | 7,993,526 | | |
| 37 | Interest and Dividend Income (419) | | 6,043,906 | 4,241,119 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 20,784,392 | 22,030,622 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | 253,942 | 3,064,489 | | |
| 40 | Gain on Disposition of Property (421.1) | | 450,000 | 7,631 | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | 34,500,967 | 37,434,568 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | | | | |
| 44 | Miscellaneous Amortization (425) | | | | | |
| 45 | Donations (426.1) | | 881,377 | 986,820 | | |
| 46 | Life Insurance (426.2) | | -2,089,825 | -2,588,290 | | |
| 47 | Penalties (426.3) | | 14,381 | -3 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 1,442,703 | 1,549,848 | | |
| 49 | Other Deductions (426.5) | | 8,164,084 | 9,203,000 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 8,412,720 | 9,151,375 | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262-263 | 20,222 | 28,463 | | |
| 53 | Income Taxes-Federal (409.2) | 262-263 | 20,849 | 560,490 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | 3,721 | 107,192 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 13,168,748 | 164,060 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 1,248,722 | 2,307,095 | | |
| 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) | | 11,964,818 | -1,446,890 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 14,123,429 | 29,730,083 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 81,198,430 | 81,956,468 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 1,508,990 | 1,515,157 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 2,152,952 | 2,033,523 | | |
| 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) | | 81,933 | 27,622 | | |
| 68 | Other Interest Expense (431) | | 7,494,378 | 6,500,414 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 8,694,285 | 10,193,622 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 83,742,398 | 81,839,562 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 206,347,317 | 189,241,920 | | |
| 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) | | 206,347,317 | 189,241,920 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | | 1,123,606,367 | 1,032,478,271 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | Benefit Plan Tax Reform Adjustment | | | |
| 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) | | 199,202,985 | 181,248,394 |
| 17 | Appropriations of Retained Earnings (Acct. 436) | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |
| 21 | | | | |
| 22 | TOTAL Appropriations of Retained Earnings (Acct. 436) | | | |
| 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 | | | -113,285,012 | ( 105,120,298) |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | -113,285,012 | ( 105,120,298) |
| 37 | Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings | | 12,062,281 | 15,000,000 |
| 38 | Balance - End of Period (Total 1,9,15,16,22,29,36,37) | | 1,221,586,621 | 1,123,606,367 |
| | APPROPRIATED RETAINED EARNINGS (Account 215) | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## STATEMENT OF RETAINED EARNINGS

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

| Line No. | Item (a) | Contra Primary Account Affected (b) | Current Quarter/Year Year to Date Balance (c) | Previous Quarter/Year Year to Date Balance (d) |
|---|---|---|---|---|
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | TOTAL Appropriated Retained Earnings (Account 215) | | | |
| | APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1) | | | |
| 46 | TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1) | | 13,273,106 | 13,273,106 |
| 47 | TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46) | | 13,273,106 | 13,273,106 |
| 48 | TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1) | | 1,234,859,727 | 1,136,879,473 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account | | | |
| | Report only on an Annual Basis, no Quarterly | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 74,667,833 | 81,674,308 |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | 7,082,051 | 7,993,526 |
| 51 | (Less) Dividends Received (Debit) | | 12,000,000 | 15,000,000 |
| 52 | | | | |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 69,749,884 | 74,667,834 |

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**Schedule Page: 118 Line No.: 37 Column: c**

| | |
|---|---|
| Transfer from Account 216.1 | 12,000,000 |
| Transferred Subsidiary Unappropriated RE from a subsidiary closed in prior years into IPC Unapproriated RE. | 62,281 |
| | 12,062,281 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities: | | |
| 2 | Net Income (Line 78(c) on page 117) | 206,347,317 | 189,241,920 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 153,958,586 | 135,048,584 |
| 5 | Amortization of | 11,378,099 | 11,644,970 |
| 6 | | | |
| 7 | | | |
| 8 | Deferred Income Taxes (Net) | 14,370,999 | 29,875,896 |
| 9 | Investment Tax Credit Adjustment (Net) | -20,660,275 | 195,726 |
| 10 | Net (Increase) Decrease in Receivables | -2,496,038 | 3,368,760 |
| 11 | Net (Increase) Decrease in Inventory | -809,418 | 7,244,713 |
| 12 | Net (Increase) Decrease in Allowances Inventory | | |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | 36,135,459 | -3,831,716 |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | 39,149,025 | -18,744,516 |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | 17,982,095 | 13,093,929 |
| 16 | (Less) Allowance for Other Funds Used During Construction | 20,784,392 | 22,030,622 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | -4,917,949 | -7,006,474 |
| 18 | Other (provide details in footnote): | -22,985,607 | -42,248,053 |
| 19 | | | |
| 20 | | | |
| 21 | | | |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21) | 416,503,799 | 309,866,065 |
| 23 | | | |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | -306,254,955 | -318,978,793 |
| 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 | -20,784,392 | -22,030,622 |
| 31 | Other (provide details in footnote): | 8,397,326 | 8,558,677 |
| 32 | | | |
| 33 | | | |
| 34 | Cash Outflows for Plant (Total of lines 26 thru 33) | -277,073,237 | -288,389,494 |
| 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 | 3,362 | 83,038 |
| 40 | Contributions and Advances from Assoc. and Subsidiary Companies | 3,838,869 | 1,400,637 |
| 41 | Disposition of Investments in (and Advances to) | | |
| 42 | Associated and Subsidiary Companies | | |
| 43 | | | |
| 44 | Purchase of Investment Securities (a) | -11,356,339 | -24,916,896 |
| 45 | Proceeds from Sales of Investment Securities (a) | 4,989,363 | 15,693,370 |
| | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 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): | -11,959 | -55,676 |
| 54 | | | |
| 55 | | | |
| 56 | Net Cash Provided by (Used in) Investing Activities | | |
| 57 | Total of lines 34 thru 55) | -279,609,941 | -296,185,021 |
| 58 | | | |
| 59 | Cash Flows from Financing Activities: | | |
| 60 | Proceeds from Issuance of: | | |
| 61 | Long-Term Debt (b) | | 120,000,000 |
| 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) | | 120,000,000 |
| 71 | | | |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | -1,063,634 | -101,063,636 |
| 74 | Preferred Stock | | |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | -240,000 | -15,912,658 |
| 77 | | | |
| 78 | Net Decrease in Short-Term Debt (c) | -21,800,000 | 21,800,000 |
| 79 | | | |
| 80 | Dividends on Preferred Stock | | |
| 81 | Dividends on Common Stock | -113,285,012 | -105,120,298 |
| 82 | Net Cash Provided by (Used in) Financing Activities | | |
| 83 | (Total of lines 70 thru 81) | -136,388,646 | -80,296,592 |
| 84 | | | |
| 85 | Net Increase (Decrease) in Cash and Cash Equivalents | | |
| 86 | (Total of lines 22,57 and 83) | 505,212 | -66,615,548 |
| 87 | | | |
| 88 | Cash and Cash Equivalents at Beginning of Period | 44,140,435 | 110,755,983 |
| 89 | | | |
| 90 | Cash and Cash Equivalents at End of period | 44,645,647 | 44,140,435 |

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

| | |
|---|---|
| **Amortization** | |
| Plant | 6,276,261 |
| Unamortized debt expense | 3,686,183 |
| Unamortized discount | 292,594 |
| Water rights | 1,042,009 |
| Other | 81,052 |
| | 11,378,099 |

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

| | |
|---|---|
| **Cash (received) paid during the period for:** | |
| Income taxes | 11,968,212 |
| Interest (net of amount capitalized) | 79,918,043 |

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

| | |
|---|---|
| **Cash Flow from Operating Activities (Other)** | |
| Pension and postretirement benefit plan expense | 28,894,314 |
| Contributions to pension and postretirement benefit plans | (46,572,678) |
| Unbilled revenues | 4,323,048 |
| Accrued payroll | 4,264,872 |
| Company owned life insurance | (1,769,784) |
| Other | (12,125,379) |
| | (22,985,607) |

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

| | |
|---|---|
| **Non-cash investing activities:** | |
| Additions to PP&E in accounts payable | 33,220,447 |

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

| | |
|---|---|
| **Other Cash Flows from Plant** | |
| Payments received from joint funding partners | 6,073,010 |
| Sale of emission allowances and renewable energy certificates | 2,059,761 |
| Other | 264,555 |
| | 8,397,326 |

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

| | |
|---|---|
| **Other Investing Cash Flows** | |
| Feasibility study costs | (112,977) |
| Miscellaneous other investing activities | 101,018 |
| | (11,959) |

**Schedule Page: 120 Line No.: 76 Column: b**

| | |
|---|---|
| **Other Financing Cash Flows** | |
| Debt issuance costs | (240,000) |
| | (240,000) |

## 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<br>(a) | Unrealized Gains and Losses on Available-for-Sale Securities<br>(b) | Minimum Pension Liability adjustment (net amount)<br>(c) | Foreign Currency Hedges<br>(d) | Other Adjustments<br>(e) |
|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | | | | ( 21,275,735) |
| 2 | Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | 2,253,040 |
| 3 | Preceding Quarter/Year to Date Changes in Fair Value | | | | ( 1,858,925) |
| 4 | Total (lines 2 and 3) | | | | 394,115 |
| 5 | Balance of Account 219 at End of Preceding Quarter/Year | | | | ( 20,881,620) |
| 6 | Balance of Account 219 at Beginning of Current Year | | | | ( 20,881,620) |
| 7 | Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | 1,882,086 |
| 8 | Current Quarter/Year to Date Changes in Fair Value | | | | ( 7,872,675) |
| 9 | Total (lines 7 and 8) | | | | ( 5,990,589) |
| 10 | Balance of Account 219 at End of Current Quarter/Year | | | | ( 26,872,209) |

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

| Line No. | Other Cash Flow Hedges Interest Rate Swaps (f) | Other Cash Flow Hedges [Insert Footnote at Line 1 to 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 | | | ( 21,275,735) | | |
| 2 | | | 2,253,040 | | |
| 3 | | | ( 1,858,925) | | |
| 4 | | | 394,115 | 189,241,922 | 189,636,037 |
| 5 | | | ( 20,881,620) | | |
| 6 | | | ( 20,881,620) | | |
| 7 | | | 1,882,086 | | |
| 8 | | | ( 7,872,675) | | |
| 9 | | | ( 5,990,589) | 206,347,317 | 200,356,728 |
| 10 | | | ( 26,872,209) | | |

| Name of Respondent | This Report Is: | Date of Report | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

NOTES TO FINANCIAL STATEMENTS

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

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

**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 engaged in the generation, transmission, distribution, sales, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the state utility regulatory commissions of Idaho and Oregon and the Federal Energy Regulatory Commission (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.

### 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, (7) accrued taxes, and (8) debt issue costs.

### Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with generally accepted accounting principles. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, 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. Accordingly, actual results could differ from those estimates.

### 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 or accrued 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 - "Regulatory Matters."

**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.

**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.

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, 2017 and 2016. 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 does not report any collections of franchise fees and similar taxes related to energy consumption on the income statement. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 - "Regulatory Matters" for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho; and
- collection in base rates of 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 deferred 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 2.9 percent in 2017 and 2.6 percent in 2016.

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. 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 long-lived assets in 2017 or 2016.

**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 7.6 percent for 2017 and 2016.

**Income Taxes**

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 - "Income Taxes."

**Other Accounting Policies**

Debt discount, expense, and premium are deferred and amortized over the terms of the respective debt issues. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

**Supplemental Cash Flows Information**

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million. Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged. Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

**Reclassifications**

In these consolidated financial statements, certain amounts in prior periods' consolidated financial statements have been reclassified to conform with current period presentation. On Idaho Power's 2016 consolidated balance sheet, the $9.5 million of American Falls and Milner water rights which had previously been reported separately was reclassified to "Other" within Deferred Debits. Also, on Idaho Power's 2016 consolidated balance sheet, $19.7 million was reclassified from "Other" in other assets to the newly created "Long-term receivables" within Deferred Debits.

**New and Recently Adopted Accounting Pronouncements**

*Recently Adopted Accounting Pronouncements*

In February 2018, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income,* which permits a reclassification from Accumulated Other Comprehensive Income (AOCI) to retained earnings for the stranded tax effects resulting from the decrease in corporate tax rate from the enactment in December 2017 of a tax reform act, generally referred to as the "Tax Cuts and Jobs Act." For more information on other impacts of the Tax Cuts and Jobs Act, see Note 2 - "Income Taxes."

*Recent Accounting Pronouncements Not Yet Adopted*

In May 2014, the FASB issued 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 FASB amended certain aspects of ASU 2014-09 to clarify the implementation guidance, including clarifications related to principal versus agent considerations, licensing and identifying performance obligations, narrow scope improvements, and practical expedients. Idaho Power has assessed the impacts of ASU 2014-09 on its financial statements and have concluded the new guidance will not affect the timing and amount of revenue recognized. However, the presentation and disclosure requirements of the standard will result in a change in the presentation of revenue on Idaho Power's consolidated statements of income as well as expanded disclosures around the disaggregation of revenue, performance obligations, and transaction price. The guidance in ASU 2014-09 is effective for interim and annual reporting periods beginning after December 15, 2017. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years (full retrospective approach) and the other requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under previous standards (modified-retrospective approach). Idaho Power will adopt ASU 2014-09 on January 1, 2018, using the modified-retrospective approach. As the standard does not change the timing and amount of revenue recognized for Idaho Power, no cumulative-effect adjustment is required.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. Idaho Power concluded the adoption will not have a material impact on its financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* intended to improve financial reporting about leasing transactions. The ASU significantly changes the accounting model used by lessees to account for leases, requiring that all material leases be presented on the balance sheet. Under the current model, some leases are classified as capital leases and recorded on the balance sheet while other leases classified as operating leases are not recognized on the balance sheet. The new standard is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. The standard must be adopted using a modified-retrospective approach. Idaho Power is evaluating the impact of ASU 2016-02 on its financial statements. Specifically, Idaho Power is considering whether the new guidance will affect its accounting for purchase power agreements, easements and rights-of-way, utility pole attachments, and other utility industry-related arrangements. At this time, Idaho Power does not know, and cannot reasonably estimate, the dollar impact of the adoption.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)*, which amends ASC 230 to clarify guidance on the classification of certain cash receipts and payments in the statement of cash flows. The FASB issued the ASU with the intent of reducing diversity in practice with respect to eight types of cash flows. Idaho Power expects the ASU to affect the classification of proceeds from the settlement of corporate-owned life insurance policies and related costs, which will be classified as investing activities under the new guidance. Idaho Power already presents debt prepayment and extinguishment costs, proceeds from the settlement of insurance claims (other than corporate-owned life insurance), and distributions received from equity-method investments in accordance with the new guidance. ASU 2016-15 is effective for interim and annual reporting periods beginning after December 15, 2017. The standard must be adopted retrospectively to all periods presented, unless impracticable to do so. Idaho Power does not believe the adoption will have a material impact on its financial statements.

In March 2017, the FASB issued ASU 2017-07, *Compensation -- Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires employers to disaggregate the service cost component from other components of net periodic benefit costs and to disclose the amounts of net periodic benefit costs that are included in each income statement line item. The standard requires employers to present the service cost component in the same line item as other compensation costs and to present the other components of net periodic benefit costs (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income. In addition, only the service cost component is eligible for capitalization. Idaho Power currently capitalizes amounts of pension or postretirement costs that are insignificant to the consolidated financial statements. The amendments in ASU 2017-07 are effective for interim and annual reporting periods beginning after December 15, 2017. Entities must use (1) a retrospective transition method to adopt the requirement for separate presentation in the income statement of service costs and other components and (2) a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service cost component. While ASU 2017-07 will result in changes to the classification of the other components of net periodic benefit costs on the consolidated statements of income of Idaho Power, the new standard will not materially affect Idaho Power’s consolidated financial statements.

**Subsequent Events**

Management has evaluated the impact of events occurring after December 31, 2017, up to February 22, 2018, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 16, 2018. 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 (dollars in thousands):

| | 2017 | 2016 |
|---|---|---|
| Federal income tax expense at 35% statutory rate | $ 89,370 | $ 78,241 |
| Change in taxes resulting from: | | |
| Equity earnings of subsidiary companies | (2,479) | (2,798) |
| AFUDC | (10,318) | (11,278) |
| Capitalized interest | 1,513 | 2,000 |
| Investment tax credits | (3,081) | (2,922) |
| Bond redemption costs | — | (4,997) |
| Removal costs | (6,280) | (5,559) |
| Capitalized overhead costs | (11,200) | (10,500) |
| Capitalized repair costs | (28,700) | (28,000) |
| State income taxes, net of federal benefit | 8,108 | 4,880 |
| Depreciation | 18,953 | 18,673 |
| Share-based compensation | (1,483) | (1,583) |
| Remeasurement of deferred taxes | 2,623 | — |
| Other, net | (8,031) | (1,855) |
| Total income tax expense | $ 48,995 | $ 34,302 |
| Effective tax rate | 19.2% | 15.3% |

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

| | 2017 | 2016 |
|---|---|---|
| **Income taxes currently payable:** | | |
| Federal | $ 44,722 | $ 464 |
| State | 10,562 | 3,767 |
| Total | 55,284 | 4,231 |
| **Income taxes deferred:** | | |
| Federal | (8,416) | 31,798 |
| State | (5,298) | (2,032) |
| Total | (13,714) | 29,766 |
| **Uncertain tax positions:** | | |
| Federal | | |
| State | | |
| Total | | |
| **Investment tax credits:** | | |
| Deferred | 10,506 | 3,227 |
| Restored | (3,081) | (2,922) |
| Total | 7,425 | 305 |
| Total income tax expense | $ 48,995 | $ 34,302 |

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

| | 2017 | 2016 |
|---|---|---|
| **Deferred tax assets:** | | |
| Regulatory liabilities | $ 98,744 | $ 51,326 |
| Deferred compensation | 21,025 | 29,424 |
| Deferred revenue | 31,086 | 40,354 |
| Tax credits | 43,995 | 33,488 |
| Retirement benefits | 94,493 | 132,362 |
| Other | 8,435 | 11,069 |
| Total | 297,778 | 298,023 |
| **Deferred tax liabilities:** | | |
| Property, plant and equipment | 306,002 | 500,987 |
| Regulatory assets | 584,329 | 948,540 |
| Power cost adjustments | — | 21,077 |
| Fixed cost adjustment | 8,016 | 17,376 |
| Retirement benefits | 103,407 | 140,083 |
| Other | 21,097 | 15,922 |
| Total | 1,022,851 | 1,643,985 |
| Net deferred tax liabilities | $ 725,073 | $ 1,345,962 |

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 and are reported as taxes accrued or income taxes receivable, respectively, on the consolidated balance sheets of Idaho Power. See Note 1 - "Summary of Significant Accounting Policies" 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 2017 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 2017 for federal and 2013-2017 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 2017, the IRS completed its examination of IDACORP's 2016 tax year with no unresolved income tax issues.

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reforms the Internal Revenue Code of 1986, as amended. Effective January 1, 2018, the Tax Cuts and Jobs Act permanently lowers the corporate tax rate to 21 percent from the existing maximum rate of 35 percent, provides for expanded bonus depreciation, limits the deductibility of interest expense, eliminates alternative minimum tax, repeals the manufacturing deduction, and imposes additional limitations on the deductibility of executive compensation. Public utility companies, such as Idaho Power, retain the full deductibility of interest expense and are excluded from the bonus depreciation provisions; however, traditional accelerated tax depreciation methods are still available.

Due to the enactment of the Tax Cuts and Jobs Act and following generally accepted accounting principles, at December 31, 2017, Idaho Power remeasured all deferred income tax assets and liabilities. The effects of these adjustments resulted in a net tax expense as shown in the rate reconciliation table above. Additionally, as shown in the deferred income tax table above, the net deferred tax liabilities at Idaho Power decreased significantly. Idaho Power's regulatory asset deferred income tax liability item decreased as the related regulatory asset was reduced in two primary ways: 1) the decrease in the federal income tax rate decreased the future cost to customers for funding the net deferred income tax liabilities resulting from the cumulative impacts of using the flow-through income tax accounting method for regulatory purposes and 2) the decrease in the federal income tax rate also reduced the net-to-gross multiplier that increases the regulatory asset to a revenue requirement carrying value. The change in income tax law also reduced the deferred income tax liability for depreciation-related timing differences under the normalized tax accounting method. As this reduction will flow back to customers in the future under the statutorily prescribed average rate assumption method, it was recorded as a regulatory liability on the consolidated balance sheets of the Idaho Power. See Note 3 - "Regulatory Matters" for more information.

The 2017 consolidated financial statements reflect the implementation of federal income tax reform as enacted and current regulatory policies. Additional adjustments may be required in future periods based upon technical corrections to the federal law, changes to state income tax policies, additional technical guidance from tax authorities, or orders from Idaho Power's regulators.

**3. REGULATORY MATTERS**

Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters.

**Regulatory Assets and Liabilities**

The application of accounting principles related to regulated operations sometimes results in Idaho Power recording some 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, 2017 | | | Total as of December 31, | |
|---|---|---|---|---|---|
| Description | Remaining Amortization Period | Earning a Return[(1)] | Not Earning a Return | 2017 | 2016 |
| **Regulatory Assets:** | | | | | |
| Income taxes [(2)] | | $ — | $ 584,329 | $ 584,329 | $ 948,540 |
| Unfunded postretirement benefits[(3)] | | — | 280,166 | 280,166 | 263,779 |
| Pension expense deferrals | | 104,688 | 23,033 | 127,721 | 105,352 |
| Energy efficiency program costs[(4)] | | 6,273 | — | 6,273 | 5,552 |
| Power supply costs[(5)] | 2018-2019 | 3,137 | — | 3,137 | 53,870 |
| Fixed cost adjustment[(5)] | 2018-2019 | 30,856 | — | 30,856 | 44,445 |
| Valmy Plant settlement stipulation[(5)] | 2018-2028 | 43,351 | 1,282 | 44,633 | — |
| Asset retirement obligations[(6)] | | — | 15,767 | 15,767 | 14,154 |
| Long-term service agreement | 2018-2043 | 16,778 | 11,129 | 27,907 | 29,081 |
| Other | 2018-2055 | 5,687 | 5,620 | 11,307 | 7,126 |
| Total | | $ 210,770 | $ 921,326 | $ 1,132,096 | $ 1,471,899 |
| **Regulatory Liabilities:** | | | | | |
| Income taxes[(7)] | | $ — | $ 98,744 | $ 98,744 | $ 51,326 |
| Depreciation-related excess deferred income taxes[(8)] | | 193,991 | — | 193,991 | — |
| Energy efficiency program costs[(4)] | | 408 | — | 408 | 10,730 |
| Power supply costs[(5)] | 2018-2019 | 5,443 | — | 5,443 | — |
| Mark-to-market assets[(10)] | | — | 22 | 22 | 7,831 |
| Other | | 5,805 | 2,991 | 8,796 | 7,114 |
| Total | | $ 205,647 | $ 101,757 | $ 307,404 | $ 77,001 |

(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 flow-through income tax accounting differences which have a corresponding deferred tax liability disclosed in Note 2 - "Income Taxes." The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For timing differences under the flow-through income tax accounting method, this reduction also reduces the associated regulatory assets generally recoverable over the remaining lives of the associated depreciable property.

(3) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11 - "Benefit Plans."

(4) The energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance.

(5) This item is discussed in more detail in this Note 3 - "Regulatory Matters."

(6) Asset retirement obligations are discussed in Note 13 - "Asset Retirement Obligations."

(7) Represents the tax gross-up related to the depreciation-related excess deferred income taxes and investment tax credits included in this table and has a corresponding deferred tax asset disclosed in Note 2 - "Income Taxes."

(8) The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For depreciation-related timing differences under the normalized tax accounting method, this reduction will flow back to customers under the statutorily prescribed average rate assumption method.

(10) Mark-to-market assets and liabilities are discussed in Note 16 - "Fair Value Measurements."

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 mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms compare Idaho Power's actual net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs being recovered in Idaho Power's retail rates. Under the power cost adjustment mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and costs being recovered in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund. 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. The Idaho deferral period or PCA year runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

***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 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 sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three most recent 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, 2017 | $ 10.6 | The net increase in PCA rates included an offsetting $13.0 million reduction for the refund of previously collected Idaho energy efficiency rider funds. |
| June 1, 2016 | $ 17.3 | The net increase in PCA rates included the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of the October 2014 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds. |

***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 (Oregon ROE) for the year is at least 100 basis points below Idaho Power’s last authorized Oregon ROE. A refund to customers will occur only to the extent that Idaho Power’s actual Oregon ROE for that year is at least 100 basis points above Idaho Power’s last authorized Oregon ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2017 and 2016 are summarized in the table that follows:

| Year and Mechanism | APCU or PCAM Adjustment |
|---|---|
| 2017 PCAM | Actual net power supply costs were within the deadband, resulting in no deferral. |
| 2017 APCU | A rate increase of $0.7 million annually took effect June 1, 2017. |
| 2016 PCAM | Actual net power supply costs were within the deadband, resulting in no deferral. |
| 2016 APCU | A rate increase of $0.2 million annually took effect June 1, 2016. |

**Notable Idaho Regulatory Matters**

***Idaho Base Rate Changes:*** Idaho base rates were most recently established in 2012, and adjusted in 2014. 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. In June 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 PCA rate that became effective June 1, 2014.

***October 2014 Idaho Settlement Stipulation:*** In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of a 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 accumulated deferred investment tax credits (ADITC) contemplated by the settlement stipulation has been amortized. The provisions of the October 2014 settlement stipulation are as follows:

- If Idaho Power's actual annual Idaho-jurisdiction return on year-end equity (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 PCA 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 PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension expense deferral regulatory asset (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.

In both 2016 and 2017, Idaho Power recorded no additional ADITC amortization and no provision for sharing with customers, as its Idaho ROE in both years was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2017, the full $45 million of additional ADITC remains available for future use under the terms 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 authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in 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 FCA years:

| FCA Year | Period Rates in Effect | Annual Amount (in millions) |
|---|---|---|
| 2016 | June 1, 2017-May 31, 2018 | $35.0 |
| 2015 | June 1, 2016-May 31, 2017 | $28.1 |

In July 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 (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA rates effective June 1, 2016.

***Hells Canyon Complex Relicensing Costs Settlement Stipulation:*** In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future rate case. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third party intervenor recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. On April 13, 2018, the settlement stipulation was approved by the IPUC substantially as filed. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017. For more information relating to HCC relicensing costs, see Note 12 - "Property, Plant and Equipment and Jointly-Owned Projects."

***Idaho Energy Efficiency Rider:*** On an annual basis, Idaho Power applies to the IPUC for an order designating Idaho Power's prior calendar year Idaho Energy Efficiency Rider (Idaho Rider) funded expenses as prudently incurred. In 2012 and 2013, the IPUC declined to decide the prudence of the increases in 2011 and 2012 Idaho Rider funded labor increases, while at the same time offering Idaho Power another opportunity to provide sufficient evidence at a future time. In 2017, Idaho Power applied to the IPUC for an order determining that the 2011 - 2016 Idaho Rider funded labor increases of $1.9 million were prudently incurred and eligible for collection through the Idaho Rider. On October 16, 2017, the IPUC issued its order determining that the 2011 - 2016 incremental Idaho Rider funded labor expenses of $1.9 million were prudently incurred. In its order, the IPUC also authorized actual Idaho Rider funded wage increases after 2016. The IPUC determined that this process does not require pre-determination as to prudence (up to a 2 percent annual cap), no longer requires labor to be examined in Idaho Power's annual prudence cases, and that the base wage level and annual cap will be reset in future general rate cases. The prudence order resulted in a $2.4 million increase in operating income in 2017.

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cut and Jobs Act was signed into law. On January 17, 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to 1) record a deferred regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in the federal income tax law and 2) to file a report with the IPUC by March 30, 2018, identifying and quantifying the income tax changes along with proposed tariff schedule changes. The IPUC order requires Idaho Power to estimate the income tax changes by comparing actual 2017 federal income tax expense components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full year of 2017.

In March 2018, Idaho Power made a filing with the IPUC providing the results of its pro forma analysis, on a system basis, indicating pro forma annual income tax expense reductions, comprised of a current income tax expense reduction and a deferred income tax expense reduction. On April 12, 2018, Idaho Power filed with the IPUC a settlement stipulation (April 2018 Settlement Stipulation) signed by Idaho Power, the IPUC Staff, and a third-party intervenor which, if approved, provides for Idaho Power customers an annual (a) direct $18.7 million reduction of customer base rates and (b) non-cash offset of $7.4 million of regulatory deferrals that would have otherwise been a future potential liability of Idaho customers, commencing June 1, 2018.

Additionally, a one-time benefit of $7.8 million will be provided to Idaho customers through Power Cost Adjustment (PCA) mechanism rates for the period from June 1, 2018 through May 31, 2019 for the income tax savings accrued from January 1, 2018 to May 31, 2018 and the income tax benefits related to the transmission tariff. On June 1, 2019, the amount provided via the PCA will decrease to $2.7 million and will cease on June 1, 2020.

The April 2018 Settlement Stipulation also provides for the indefinite extension of the October 2014 Settlement Stipulation beyond the initial termination date of December 31, 2019, with the following modified terms to become effective beginning January 1, 2020:

- Idaho Power will have available and may continue to use any unused portion of the $45 million ADITC from the October 2014 settlement.

- If Idaho Power's annual Idaho ROE in any year is less than 9.4 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.4 percent Idaho ROE for that year, so long as the cumulative amount of ADITC used does not exceed $45 million; however, upon approval of the IPUC, Idaho Power may replenish the total amount of ADITC it is permitted to amortize.

- 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 80 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, and 20 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 55 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension expense deferral regulatory asset (to reduce the amount to be collected in the future from Idaho customers), and 20 percent to Idaho Power.

- In the event the IPUC approves a change to Idaho Power's allowed annual Idaho ROE as part of a general rate case proceeding effective on or after January 1, 2020, the ROE thresholds will be adjusted on a prospective basis as follows: (a) the Idaho ROE thresholds under which Idaho Power will be permitted to amortize an additional amount of ADITC will be set at 95 percent of the newly authorized ROE, (b) sharing with customers on an 80 percent basis as a customer rate reduction will begin at the newly authorized Idaho ROE, and (c) sharing with customers on an 80 percent basis but allocated 55 percent to a rate reduction, and 25 percent to a pension expense deferral regulatory asset, will begin at 105 percent of the newly authorized ROE.

Neither the October 2014 Settlement Stipulation nor the April 2018 Settlement Stipulation order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the respective terms.

On December 29, 2017, Idaho Power filed an application with the OPUC, requesting authority to defer for later ratemaking treatment the Oregon jurisdictional earnings in excess of the currently authorized Oregon jurisdictional rate of return on equity that may result from the Tax Cuts and Jobs Act, as measured from the Company’s annual Oregon Results of Operations. On December 29, 2017, OPUC Staff also filed an application with the OPUC requesting authority to defer for later ratemaking treatment the difference between Idaho Power’s current retail rates and its current retail rates inclusive of the impact of the Tax Cuts and Jobs Act.

Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law may benefit Idaho Power customers and affect Idaho Power's financial condition and results of operations. The method through which potential cost savings may be accrued for the benefit of customers, including potential reductions to customer rates and to regulatory deferrals, will require approval from the IPUC and OPUC.

**Valmy Base Rate Adjustment Settlement Stipulations**

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for Idaho Power’s jointly-owned North Valmy coal-fired power plant (Valmy Plant). The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017, in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted.

**Depreciation Rate Settlement Stipulations**

In May 2017, the IPUC and OPUC approved settlement stipulations related to revised depreciation rates for Idaho Power's electric plant in service other than the Valmy Plant, and adjusted base rates in Oregon to reflect the revised depreciation rates applied to electric plant-in-service based on balances from the most recent general rate case. These settlement stipulations provided for new depreciation rates to go into effect on June 1, 2017, with no significant resulting increase in revenue.

**Western Energy Imbalance Market Costs**

Idaho Power plans to participate in a new energy imbalance market implemented in the western United States (Western EIM). In August 2016, Idaho Power filed an application with the IPUC requesting specified regulatory accounting treatment associated with its participation in the Western EIM. In January 2017, the IPUC issued an order authorizing Idaho Power’s requested deferral accounting treatment for costs associated with joining the Western EIM. Idaho Power can defer costs incurred until the earlier of when Idaho Power begins recovery of the costs and the deferral balance or the end of 2018. Idaho Power anticipates that its participation in the Western EIM will commence in April 2018.

In November 2017, Idaho Power filed an application with the IPUC requesting approval to establish an interim method of recovery for costs associated with participation in the Western EIM. If the IPUC approves the application as filed, Idaho Power intends to include $3.6 million in costs for recovery through the PCA, beginning June 1, 2018.

**Notable Oregon Regulatory Matters**

***Oregon Base Rate Changes:*** Oregon base rates were most recently established in a general rate case in 2012. In February 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, in September 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**

Idaho Power uses 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, 2017 to September 30, 2018 | $ 34.90 |
| October 1, 2016 to September 30, 2017 | $ 25.52 |
| October 1, 2015 to September 30, 2016 | $ 23.43 |

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $130.4 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):

| | 2017 | 2016 |
|---|---|---|
| First mortgage bonds: | | |
| 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 |
| 6.00% 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 |
| 3.65% Series due 2045 | 250,000 | 250,000 |
| 4.05% Series due 2046 | 120,000 | 120,000 |
| Total first mortgage bonds | 1,575,000 | 1,575,000 |
| 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 | — | 1,064 |
| Unamortized issuance costs and discounts | (4,125) | (4,417) |
| Total Idaho Power outstanding debt(2) | 1,761,220 | 1,761,992 |

(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, 2017, to $1.741 billion.

(2) At December 31, 2017 and 2016, the overall effective cost rate of Idaho Power's outstanding debt was 4.87 percent.

At December 31, 2017, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

| 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|
| $ — | $ — | $ 230,000 | $ — | $ 75,000 | $ 1,460,345 |

**Long-Term Debt Issuances, Maturities, and Availability**

On March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. On April 11, 2016, Idaho Power redeemed, prior to maturity, $100 million in principal amount of 6.15% first mortgage bonds, medium-term notes, Series H, due April 2019. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $14.0 million. Idaho Power used a portion of the net proceeds from the March 2016 sale of first mortgage bonds, medium-term notes to effect the redemption.

On March 6, 2015, Idaho Power issued $250.0 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120.0 million in principal amount of 6.025% first mortgage bonds, secured medium-term notes, Series H, due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million. Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April and May 2016, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (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. The order from the IPUC approved the issuance of the securities through May 31, 2019, subject to extensions 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 requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum all-in interest rate limit of 7.0 percent.

On May 20, 2016, IDACORP and Idaho Power filed a joint shelf registration statement with the U.S. Securities and Exchange Commission (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 September 27, 2016, Idaho Power entered into a selling agency agreement with seven 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 K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture. The Forty-eighth Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture. As of December 31, 2017, $500 million in principal amount of Series K Notes remained available for issuance under the Indenture.

On March 16, 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, secured medium-term notes, Series K, maturing on March 1, 2048. On April 17, 2018, Idaho Power redeemed, prior to maturity, $130 million in principal amount of 4.50% first mortgage bonds, medium-term notes, Series H due April 2020. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of $5 million.  Idaho Power used a portion of the net proceeds from the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

***Mortgage*:** As of December 31, 2017, Idaho Power could issue under its Indenture approximately $1.8 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.

The Forty-eighth Supplemental Indenture increased the maximum amount of first mortgage bonds issuable by Idaho Power under the Indenture from $2.0 billion to $2.5 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

On November 6, 2015, Idaho Power entered into a Credit Agreement replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide credit facilities 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, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facilities 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, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent. 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, Idaho Power 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 provides for an original maturity date of November 6, 2020, the credit agreements grant Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On November 7, 2017, Idaho Power executed the second extension agreement with the consent of all the lenders, extending the maturity date under the credit agreement to November 4, 2022. No other terms of the credit facility, included the amount of permitted borrowing under the credit agreement, were affected by the extension.

At December 31, 2017, no loans were outstanding under Idaho Power's facility. At December 31, 2017, 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 the interest rate of Idaho Power's short-term borrowings was as follows at December 31, 2017, and December 31, 2016:

| | | 2017 | | 2016 |
|---|---|---|---|---|
| **Commercial paper balances:** | | | | |
| At the end of year | $ | — | $ | 21,800 |
| Average during the year | $ | 839 | $ | 438 |
| **Weighted-average interest rate** | | | | |
| At the end of the year | % | —% | | 1.13% |

## 6. COMMON STOCK

### Idaho Power Common Stock

No contributions were made to Idaho Power in 2017 or 2016 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 its credit facility or Idaho Power’s Revised Code of Conduct. A covenant under Idaho Power’s credit facility requires 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, 2017, the leverage ratio for Idaho Power was 46 percent. Based on these restrictions, Idaho Power’s dividends were limited to $1.1 billion at December 31, 2017. 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, 2017, 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, 2017, Idaho Power's common equity capital was 54 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 (FPA) prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the FPA 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. SHARE-BASED COMPENSATION**

Through its parent company IDACORP, Idaho Power has one share-based compensation plan -- the 2000 Long-Term Incentive and Compensation Plan (LTICP). The 1994 Restricted Stock Plan was terminated effective February 9, 2017. The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock and restricted stock units (together, Restricted Stock), performance shares and performance-based units (together, Performance-Based Shares), and several other types of share-based awards. At December 31, 2017, the maximum number of shares available under the LTICP was 836,220.

***Restricted Stock and Performance-Based Shares Awards***

Restricted Stock awards have three-year vesting periods and entitle the recipients to dividends or dividend equivalents, as applicable, and voting rights, except that holders of restricted stock units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 Shares awards have three-year vesting periods and entitle the recipients to voting rights, except that holders of performance-based units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 and the year issued, the final number of shares awarded can range from zero to 200 percent of the target award. Dividends or dividend equivalents, as applicable, 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-Based Shares award activity is presented below. Share amounts represent the shares of IDACORP common stock:

| | Number of Shares/Units | Weighted-Average Grant Date Fair Value |
|---|---|---|
| Nonvested shares/units at January 1, 2017 | $ 199,526 | $ 61.51 |
| Shares/units granted | 95,568 | 75.40 |
| Shares/units forfeited | (6,179) | 75.54 |
| Shares/units vested | (89,263) | 51.07 |
| Nonvested shares/units at December 31, 2017 | $ 199,652 | $ 72.39 |

The total fair value of shares vested was $7.5 million in 2017 and $8.3 million in 2016. At December 31, 2017, Idaho Power had $5.4 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.7 years. Original issue and/or treasury shares of IDACORP are used for these awards.

In 2017, a total of 12,050 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $82.93 per share. Directors elected to defer receipt of 3,012 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

***Compensation Expense:*** The following table shows Idaho Power's share of the compensation cost recognized in income and the tax benefits resulting from the LTICP (in thousands of dollars):

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Compensation cost | $ 7,304 | $ 5,494 | $ 5,221 |
| Income tax benefit | 2,856 | 2,148 | 2,042 |

No equity compensation costs have been capitalized. These costs are primarily reported within other operations and maintenance expense in the consolidated statements of income.

## 8. COMMITMENTS

### Purchase Obligations

At December 31, 2017, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Cogeneration and power production | $ 234,094 | $ 229,129 | $ 230,734 | $ 236,644 | $ 242,380 | $ 2,951,425 |
| Fuel | 42,772 | 29,450 | 27,671 | 27,861 | 8,389 | 92,588 |

As of December 31, 2017, Idaho Power had 1,114 MW nameplate capacity of PURPA-related projects on-line, with an additional 5 MW nameplate capacity of projects projected to be on-line in 2018 and an additional 24 MW expected to be added in 2019. 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 $170 million in 2017 and $154 million in 2016.

Idaho Power also has the following long-term commitments (in thousands of dollars):

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Operating leases(1) | $ 3,529 | $ 4,434 | $ 4,538 | $ 4,500 | $ 4,507 | $ 30,052 |
| Equipment, maintenance, and service agreements(1) | 35,867 | 10,378 | 11,828 | 6,421 | 10,322 | 53,572 |
| FERC and other industry-related fees(1) | 12,940 | 12,836 | 10,145 | 10,145 | 10,145 | 50,729 |

(1) Approximately $34 million, $20 million, and $60 million of the obligations included in operating leases; equipment, maintenance, and service agreements; and FERC and other industry-related fees, respectively, have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

Idaho Power’s expense for operating leases was $5.6 million in 2017 and $4.9 million in 2016.

### 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 $56.7 million at December 31, 2017, representing IERCo's one-third share of BCC's total reclamation obligation of $170.1 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2017, the value of the reclamation trust fund was $103.4 million. During 2017, the reclamation trust fund made no distributions 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, and does, add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on its historical experience and the evaluation of the specific indemnities. As of December 31, 2017, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on its consolidated balance sheets with respect to these indemnification obligations.

**9. CONTINGENCIES**

Idaho Power has in the past and expects in the future to become involved in various claims, controversies, disputes, and other contingent matters, some of which 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, as applicable, 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. 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 its 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, although there is no assurance that such recovery would be granted.

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, record an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report, Idaho Power believes that resolution of those matters will not have a material adverse effect on its consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations and recently issued executive orders related to environmental matters 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.

**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 two nonqualified defined benefit pension plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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 2017 and 2016, 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 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| **Change in projected benefit obligation:** | | | | |
| Benefit obligation at January 1 | $ 895,060 | $ 835,523 | $ 99,570 | $ 95,389 |
| Service cost | 33,742 | 32,019 | 759 | 1,228 |
| Interest cost | 38,957 | 37,813 | 4,315 | 4,275 |
| Actuarial loss | 67,758 | 22,640 | 10,635 | 2,933 |
| Plan amendment | — | 81 | — | 120 |
| Benefits paid | (36,173) | (33,016) | (4,976) | (4,375) |
| Projected benefit obligation at December 31 | 999,344 | 895,060 | 110,303 | 99,570 |
| **Change in plan assets:** | | | | |
| Fair value at January 1 | 607,568 | 559,616 | — | — |
| Actual return on plan assets | 86,288 | 40,968 | — | — |
| Employer contributions | 40,000 | 40,000 | — | — |
| Benefits paid | (36,173) | (33,016) | — | — |
| Fair value at December 31 | 697,683 | 607,568 | — | — |
| Funded status at end of year | $ (301,661) | $ (287,492) | $ (110,303) | $ (99,570) |
| **Amounts recognized in the statement of financial position consist of:** | | | | |
| Other current liabilities | $ — | $ — | $ (5,010) | $ (4,733) |
| Noncurrent liabilities | (301,661) | (287,492) | (105,293) | (94,837) |
| Net amount recognized | $ (301,661) | $ (287,492) | $ (110,303) | $ (99,570) |
| **Amounts recognized in accumulated other comprehensive income consist of:** | | | | |
| Net loss | $ 277,052 | $ 263,634 | $ 41,333 | $ 33,660 |
| Prior service cost | 68 | 96 | 498 | 625 |
| Subtotal | 277,120 | 263,730 | 41,831 | 34,285 |
| Less amount recorded as regulatory asset | (277,120) | (263,730) | — | — |
| Net amount recognized in accumulated other comprehensive income | $ — | $ — | $ 41,831 | $ 34,285 |
| **Accumulated benefit obligation** | $ 850,763 | $ 766,367 | $ 100,222 | $ 91,146 |

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 recorded value of these investments was approximately $85.7 million and $77.8 million at December 31, 2017 and 2016, 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 | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Service cost | $ 33,742 | $ 32,019 | $ 759 | $ 1,228 |
| Interest cost | 38,957 | 37,813 | 4,315 | 4,275 |
| Expected return on assets | (45,138) | (42,081) | — | — |
| Amortization of net loss | 13,190 | 13,331 | 2,963 | 3,532 |
| Amortization of prior service cost | 28 | 59 | 127 | 168 |
| Net periodic pension cost | 40,779 | 41,141 | 8,164 | 9,203 |
| Regulatory deferral of net periodic benefit cost(1) | (38,699) | (39,335) | — | — |
| Previously deferred pension cost recognized(1) | 17,154 | 17,154 | — | — |
| Net periodic benefit cost recognized for financial reporting(1) | $ 19,234 | $ 18,960 | $ 8,164 | $ 9,203 |

(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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those 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 | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Actuarial (loss) gain during the year | $ (26,608) | $ (23,753) | $ (10,635) | $ (2,933) |
| Plan amendment service cost | — | (81) | — | (120) |
| Reclassification adjustments for: | | | | |
| Amortization of net loss | 13,190 | 13,331 | 2,963 | 3,532 |
| Amortization of prior service cost | 28 | 59 | 127 | 168 |
| Adjustment for deferred tax effects | 1,744 | 4,083 | 1,555 | (253) |
| Adjustment due to the effects of regulation | 11,646 | 6,361 | — | — |
| Other comprehensive income recognized related to pension benefit plans | $ — | $ — | $ (5,990) | $ 394 |

In 2018, Idaho Power expects to recognize as components of net periodic benefit cost $17.5 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2017, relating to the pension plan and SMSP. This amount consists of $13.6 million of amortization of net loss for the pension plan and $3.8 million of amortization of net loss and $0.1 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):

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023-2027 |
|---|---|---|---|---|---|---|
| Pension Plan | $ 35,312 | $ 37,490 | $ 39,983 | $ 42,438 | $ 44,797 | $ 257,290 |
| SMSP | 5,100 | 5,161 | 5,538 | 5,707 | 5,880 | 30,962 |

As of December 31, 2017, Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2018. Depending on market conditions and cash flow considerations in 2018, Idaho Power could contribute up to $40 million to the pension plan during 2018 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

**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):

| | 2017 | 2016 |
|---|---|---|
| **Change in accumulated benefit obligation:** | | |
| Benefit obligation at January 1 | $ 63,876 | $ 62,393 |
| Service cost | 973 | 1,116 |
| Interest cost | 2,783 | 2,766 |
| Actuarial loss | 5,769 | 1,550 |
| Benefits paid(1) | (3,562) | (3,949) |
| Plan amendments | 212 | — |
| Benefit obligation at December 31 | 70,051 | 63,876 |
| **Change in plan assets:** | | |
| Fair value of plan assets at January 1 | 34,999 | 35,566 |
| Actual return on plan assets | 5,112 | 2,425 |
| Employer contributions(1) | 1,745 | 957 |
| Benefits paid(1) | (3,562) | (3,949) |
| Fair value of plan assets at December 31 | 38,294 | 34,999 |
| Funded status at end of year (included in noncurrent liabilities) | $ (31,757) | $ (28,877) |

(1) Contributions and benefits paid are each net of $3.4 million and $3.7 million of plan participant contributions for 2017 and 2016, respectively.

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

| | 2017 | 2016 |
|---|---|---|
| Net gain | $ 2,777 | $ (55) |
| Prior service cost | 269 | 104 |
| Subtotal | 3,046 | 49 |
| Less amount recognized in regulatory assets | (3,046) | (49) |
| Net amount recognized in accumulated other comprehensive income | $ — | $ — |

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

| | 2017 | 2016 |
|---|---|---|
| Service cost | $ 973 | $ 1,116 |
| Interest cost | 2,783 | 2,766 |
| Expected return on plan assets | (2,307) | (2,474) |
| Amortization of prior service cost | 47 | 26 |
| Net periodic postretirement benefit cost | $ 1,496 | $ 1,434 |

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

| | 2017 | 2016 |
|---|---|---|
| Actuarial (loss) gain during the year | $ (2,964) | $ (1,600) |
| Prior service cost arising during the year | (212) | — |
| Reclassification adjustments for amortization of prior service cost | 47 | 26 |
| Adjustment for deferred tax effects | 807 | 615 |
| Adjustment due to the effects of regulation | 2,322 | 959 |
| Other comprehensive income related to postretirement benefit plans | $ — | $ — |

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

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023-2027 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 5,051 | $ 4,667 | $ 4,374 | $ 4,080 | $ 4,070 | $ 19,910 |

**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 | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| Discount rate | 3.95% | 4.45% | 3.95% | 4.45% | 3.95% | 4.45% |
| Rate of compensation increase(1) | 4.17% | 4.11% | 4.75% | 4.75% | — | — |
| Medical trend rate | — | — | — | — | 6.8% | 8.3% |
| Dental trend rate | — | — | — | — | 4.1% | 5.0% |
| Measurement date | 12/31/2017 | 12/31/2016 | 12/31/2017 | 12/31/2016 | 12/31/2017 | 12/31/2016 |

(1) The 2017 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.67% 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 | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| Discount rate | 4.45% | 4.60% | 4.45% | 4.60% | 4.45% | 4.60% |
| Expected long-term rate of return on assets | 7.50% | 7.50% | — | — | 6.75% | 7.25% |
| Rate of compensation increase | 4.17% | 4.11% | 4.75% | 4.50% | — | —% |
| Medical trend rate | — | — | — | — | 6.8% | 8.30% |
| Dental trend rate | — | — | — | — | 4.0% | 5.00% |

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.8 percent in 2017 and is assumed to decrease to 6.4 percent in 2018, 5.9 percent in 2019, 5.4 percent in 2020 and to gradually decrease to 4.1 percent by 2074. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 4.0 percent, or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2017 (in thousands of dollars):

| | One-Percentage-Point | |
|---|---|---|
| | **Increase** | **Decrease** |
| Effect on total of cost components | $ 301 | $ (223) |
| Effect on accumulated postretirement benefit obligation | 3,166 | (2,459) |

**Plan Assets**

***Pension Asset Allocation Policy:*** The target allocation and actual allocations at December 31, 2017, for the pension asset portfolio by asset class is set forth below:

| Asset Class | Target Allocation | Actual Allocation December 31, 2017 |
|---|---|---|
| Debt securities | 24% | 24% |
| Equity securities | 56% | 58% |
| Real estate | 7% | 6% |
| Other plan assets | 13% | 12% |
| 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, 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 - "Derivative Financial Instruments." The following table presents the fair value of the plans' investments by asset category (in thousands of dollars).

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets at December 31, 2017** | | | | |
| Cash and cash equivalents | $ 20,852 | $ — | $ — | $ 20,852 |
| Short-term bonds | 20,475 | — | — | 20,475 |
| Intermediate bonds | 20,699 | 82,923 | — | 103,622 |
| Long-term bonds | — | 40,707 | — | 40,707 |
| Equity Securities: Large-Cap | 95,179 | — | — | 95,179 |
| Equity Securities: Mid-Cap | 81,127 | — | — | 81,127 |
| Equity Securities: Small-Cap | 62,502 | — | — | 62,502 |
| Equity Securities: Micro-Cap | 32,753 | — | — | 32,753 |
| Equity Securities: International | 6,774 | — | — | 6,774 |
| Equity Securities: Emerging Markets | 8,785 | — | — | 8,785 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Equity Securities: International | | | | 83,589 |
| Equity Securities: Emerging Markets | | | | 36,255 |
| Real estate | | | | 38,435 |
| Private market investments | | | | 31,618 |
| Commodities fund | | | | 35,010 |
| **Total** | $ 349,146 | $ 123,630 | $ — | $ 697,683 |
| Postretirement plan assets(1) | $ 567 | $ 37,727 | $ — | $ 38,294 |

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets at December 31, 2016** | | | | |
| Cash and cash equivalents | $ 28,632 | $ — | $ — | $ 28,632 |
| Short-term bonds | 11,198 | — | — | 11,198 |
| Intermediate bonds | 11,904 | 88,734 | — | 100,638 |
| Long-term bonds | — | 20,573 | — | 20,573 |
| Equity Securities: Large-Cap | 80,582 | — | — | 80,582 |
| Equity Securities: Mid-Cap | 68,634 | — | — | 68,634 |
| Equity Securities: Small-Cap | 53,766 | — | — | 53,766 |
| Equity Securities: Micro-Cap | 29,671 | — | — | 29,671 |
| Equity Securities: International | 7,782 | — | — | 7,782 |
| Equity Securities: Emerging Markets | 9,204 | — | — | 9,204 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Equity Securities: International | | | | 64,930 |
| Equity Securities: Emerging Markets | | | | 24,443 |
| Real estate | | | | 41,907 |
| Private market investments | | | | 33,713 |
| Commodities fund | | | | 31,895 |
| **Total** | $ 301,373 | $ 109,307 | $ — | $ 607,568 |
| Postretirement plan assets(1) | $ 28 | $ 34,971 | $ — | $ 34,999 |

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

For the year ended December 31, 2017 and December 31, 2016, there were no material transfers into or out of Levels 1, 2, or 3.

***Fair Value Measurement of Level 2 Plan assets and Plan assets measured at NAV:***

Level 2 Bonds: These investments represent U.S. government, agency bonds, and corporate bonds. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing market prices for similar assets or liabilities in active markets.

Level 2 Postretirement Asset: This asset represents an investment in a life insurance contract and is 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.

Commingled Funds: These funds, made up of the international, emerging markets equity securities, and commodities fund measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The value of the commingled funds are presented at estimated fair value, which is determined based on the unit value of the fund. The values of these investments are calculated by the custodian for the fund company on a monthly or more frequent basis, and are based on market prices of the assets held by each of the commingled funds divided by the number of fund shares outstanding for the respective fund. The investments in commingled funds have redemption limitations that permit monthly redemption following notice requirements of 5 to 7 days.

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 companies, 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. Redemptions are generally available on a quarterly basis, with 10 to 35 days written notice, depending on the individual fund. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV or the fund’s estimate of fair value at the end of the quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. To protect other fund holders, real estate funds have no duty to liquidate or encumber funds to meet redemption requests.

Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund companies based on the estimated fair values of the underlying fund holdings divided by the fund shares outstanding or multiplied by the ownership percentages of the holder. 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. Redemptions are available on a quarterly basis with 70 days written notice. Redemptions will be processed at the quarterly NAV or fair value within 60 days following quarter end. In the event of a full redemption, a reserve amount of 5% to 10% of the redemption amount may be held in reserve until the audited financial statements of the fund are published. This allows the fund to adjust the redemption so that other fund holders are not adversely impacted. Venture capital fund investments are valued by the fund companies 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. These funds are formed for a stated life of 10 to 15 years. The general partner can extend the fund life for 2 or 3 one-year periods. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

**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 $7.4 million, $7.5 million, and $6.9 million in 2017, 2016, and 2015, respectively.

**Post-employment Benefits**

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefits included in other deferred credits on Idaho Power's consolidated balance sheets at December 31, 2017 and 2016, were approximately $2 million.

**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 ended December 31, 2017 and 2016 (in thousands of dollars):

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | **Balance** | **Avg Rate** | **Balance** | **Avg Rate** |
| Production | $ 2,598,940 | 3.07% | $ 2,551,823 | 2.40% |
| Transmission | 1,163,240 | 1.94% | 1,120,903 | 2.02% |
| Distribution | 1,710,126 | 2.44% | 1,637,131 | 2.72% |
| General and Other | 433,856 | 6.01% | 422,187 | 5.49% |
| Total in service | 5,906,162 | 2.87% | 5,732,044 | 2.64% |
| Accumulated provision for depreciation | (2,098,274) | | (1,988,477) | |
| In service - net | $ 3,807,888 | | $ 3,743,567 | |

At December 31, 2017, Idaho Power's construction work in progress balance of $452.4 million included relicensing costs of $268.7 million for the HCC, Idaho Power's largest hydroelectric complex. In 2017, 2016, and 2015, the IPUC authorized Idaho Power to include in its Idaho jurisdiction rates $6.5 million annually ($10.7 million when grossed-up for the effect of income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2017, Idaho Power's accumulated provision for rate refunds for collection of AFUDC relating to the HCC was $119.7 million.

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, 2017 (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 | $ 722,440 | $ 6,935 | $ 316,092 | 33 | 771 |
| Boardman | Boardman, OR | 82,193 | 55 | 71,250 | 10 | 64 |
| Valmy Units 1 and 2 | Winnemucca, NV | 409,836 | 359 | 235,670 | 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 $86.4 million in 2017 and $92.9 million in 2016.

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 $9.8 million in 2017 and $7.8 million in 2016.

**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.

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 - "Regulatory Matters" for the removal costs recorded as regulatory liabilities on Idaho Power's consolidated balance sheets as of December 31, 2017 and 2016.

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

| | 2017 | 2016 |
|---|---|---|
| Balance at beginning of year | $ 26,257 | $ 26,153 |
| Accretion expense | 1,015 | 1,031 |
| Revisions in estimated cash flows | (791) | 1,759 |
| Liability settled | (66) | (2,686) |
| Balance at end of year | $ 26,415 | $ 26,257 |

**13. INVESTMENTS**

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

| | 2017 | 2016 |
|---|---|---|
| Idaho Power investments: | | |
| IERCO | $ 72,213 | $ 77,131 |
| Exchange traded short-term bond funds and cash equivalents | 30,249 | 23,908 |
| Executive deferred compensation plan investments | 17 | 111 |
| Total Idaho Power investments | 102,479 | 101,150 |

**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, 2017 and December 31, 2016. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Proceeds from sales | $ 4,989 | $ 15,693 | $ 34,243 |
| Gross realized gains from sales | — | 54 | — |

**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, 2017 and 2016 (in thousands of dollars):

| | Location of Realized Gain/(Loss) on Derivatives Recognized in Income | Gain/(Loss) on Derivatives Recognized in Income[1] | |
|---|---|---|---|
| | | 2017 | 2016 |
| Financial swaps | Off-system sales | $ 902 | $ 1,405 |
| Financial swaps | Purchased power | 166 | 586 |
| Financial swaps | Fuel expense | 701 | (1,947) |
| Financial swaps | Other operations and maintenance | (84) | (161) |
| Forward contracts | Off-system sales | 55 | (54) |
| Forward contracts | Purchased power | (69) | 86 |
| Forward contracts | Fuel expense | 4 | 139 |

(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 - "Fair Value Measurements" 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, 2017 and 2016 (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, 2017** | | | | | | | |
| Current: | | | | | | | |
| Financial swaps | Other current assets | $ 18 | $ — | $ 18 | $ — | $ — | $ — |
| Financial swaps | Other current liabilities | 553 | (553) | — | 1,971 | (748) (1) | 1,223 |
| Forward contracts | Other current liabilities | — | — | — | 2 | — | 2 |
| Long-term: | | | | | | | |
| Financial swaps | Other assets | 4 | — | 4 | — | — | — |
| Total | | $ 575 | $ (553) | $ 22 | $ 1,973 | $ (748) | $ 1,225 |
| **December 31, 2016** | | | | | | | |
| Current: | | | | | | | |
| Financial swaps | Other current assets | $ 8,134 | $ (2,183) (2) | $ 5,951 | $ 302 | $ (302) | $ — |
| Total | | $ 8,134 | $ (2,183) | $ 5,951 | $ 302 | $ (302) | $ — |

(1) Current liability derivative amounts offset include $0.2 million of collateral receivable for the period ending December 31, 2017.

(2) Current asset derivative amounts offset include $1.9 million of collateral payable for the period ending December 31, 2016.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2017 and 2016 (in thousands of units):

| | | December 31, | |
|---|---|---|---|
| **Commodity** | **Units** | **2017** | **2016** |
| Electricity purchases | MWh | 312 | 217 |
| Electricity sales | MWh | 224 | 135 |
| Natural gas purchases | MMBtu | 7,028 | 6,604 |
| Natural gas sales | MMBtu | 140 | 70 |
| Diesel purchases | Gallons | — | 1,188 |

**Credit Risk**

At December 31, 2017, 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, 2017, was $2.0 million. Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2017, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $4.5 million to cover open liability positions as well as completed transactions that have not yet been paid.

**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, 2017 and 2016.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2017 and 2016 (in thousands of dollars):

| | **December 31, 2017** | | | | **December 31, 2016** | | | |
|---|---|---|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Assets:** | | | | | | | | |
| Money market funds | $10,260 | $— | $— | $10,260 | $29,967 | $— | $— | $29,967 |
| Derivatives | 22 | — | — | 22 | 5,951 | — | — | 5,951 |
| Trading securities: Equity securities | 17 | — | — | 17 | 111 | — | — | 111 |
| Available-for-sale securities: Equity securities | 30,249 | — | — | 30,249 | 23,908 | — | — | 23,908 |
| **Liabilities:** | | | | | | | | |
| Derivatives | $ 1,223 | $ 2 | $ — | $ 1,225 | $ — | $ — | $ — | $ — |

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, are held in a Rabbi trust, and are actively traded money market and exchange-traded 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, 2017 and 2016, using available market information and appropriate valuation methodologies (in thousands of dollars):

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| | (thousands of dollars) | | | |
| **Liabilities:** | | | | |
| Long-term debt(1) | $ 1,746,123 | $ 1,915,459 | $ 1,745,678 | $ 1,858,666 |

(1) Long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 15 - "Fair Value Measurements."

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 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, 2017, 2016, and 2015 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

| | Year Ended December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Defined benefit pension items | | |
| Balance at beginning of period | $ (20,882) | $ (21,276) |
| Other comprehensive income before reclassifications | (7,872) | (1,859) |
| Amounts reclassified out of AOCI to net income | 1,882 | 2,253 |
| Net current-period other comprehensive income | (5,990) | 394 |
| Balance at end of period | $ (26,872) | $ (20,882) |

The table below presents the effects on net income of amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2017 and 2016 (in thousands of dollars). Items in parentheses indicate increases to net income.

| | Amount Reclassified from AOCI | |
|---|---|---|
| | Year Ended December 31, | |
| | 2017 | 2016 |
| Amortization of defined benefit pension items[1] | | |
| Prior service cost | $ 127 | $ 168 |
| Net loss | 2,963 | 3,532 |
| Total before tax | 3,090 | 3,700 |
| Tax benefit[2] | (1,208) | (1,447) |
| Net of tax | 1,882 | 2,253 |
| Total reclassification for the period | $ 1,882 | $ 2,253 |

[1] Amortization of these items is included in Idaho Power's consolidated income statements in other expense, net.

[2] The tax benefit is included in income tax expense in the consolidated income statements of Idaho Power.

**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 $0.7 million in 2017 and $0.8 million in 2016.

At December 31, 2017 and 2016, Idaho Power had a $57.3 million and $0.9 million payable to IDACORP, respectively, which was included in its accounts payable to affiliates balance on its consolidated balance sheets.

***Ida-West:*** Idaho Power purchases all of the power generated by four of Ida-West’s hydroelectric projects located in Idaho. Idaho Power paid Ida-West $9.8 million in 2017 and $7.8 in 2016.

## 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) | 5,905,411,061 | 5,905,411,061 |
| 4 | Property Under Capital Leases | | |
| 5 | Plant Purchased or Sold | | |
| 6 | Completed Construction not Classified | | |
| 7 | Experimental Plant Unclassified | | |
| 8 | Total (3 thru 7) | 5,905,411,061 | 5,905,411,061 |
| 9 | Leased to Others | | |
| 10 | Held for Future Use | 8,074,933 | 8,074,933 |
| 11 | Construction Work in Progress | 452,424,340 | 452,424,340 |
| 12 | Acquisition Adjustments | 750,893 | 750,893 |
| 13 | Total Utility Plant (8 thru 12) | 6,366,661,227 | 6,366,661,227 |
| 14 | Accum Prov for Depr, Amort, & Depl | 2,283,266,546 | 2,283,266,546 |
| 15 | Net Utility Plant (13 less 14) | 4,083,394,681 | 4,083,394,681 |
| 16 | Detail of Accum Prov for Depr, Amort & Depl | | |
| 17 | In Service: | | |
| 18 | Depreciation | 2,256,354,154 | 2,256,354,154 |
| 19 | Amort & Depl of Producing Nat Gas Land/Land Right | | |
| 20 | Amort of Underground Storage Land/Land Rights | | |
| 21 | Amort of Other Utility Plant | 26,879,853 | 26,879,853 |
| 22 | Total In Service (18 thru 21) | 2,283,234,007 | 2,283,234,007 |
| 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 | 32,539 | 32,539 |
| 33 | Total Accum Prov (equals 14) (22,26,30,31,32) | 2,283,266,546 | 2,283,266,546 |

## 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 | 30,032,675 | 697,008 |
| 4 | (303) Miscellaneous Intangible Plant | 22,702,225 | 7,554,831 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 52,740,603 | 8,251,839 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A. Steam Production Plant | | |
| 8 | (310) Land and Land Rights | 1,722,421 | |
| 9 | (311) Structures and Improvements | 151,560,962 | 3,140,755 |
| 10 | (312) Boiler Plant Equipment | 758,144,425 | 5,849,270 |
| 11 | (313) Engines and Engine-Driven Generators | | |
| 12 | (314) Turbogenerator Units | 165,721,669 | 5,012,328 |
| 13 | (315) Accessory Electric Equipment | 72,133,547 | 1,898,503 |
| 14 | (316) Misc. Power Plant Equipment | 17,503,532 | 3,927,182 |
| 15 | (317) Asset Retirement Costs for Steam Production | 15,311,883 | -421,992 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 1,182,098,439 | 19,406,046 |
| 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 | 31,444,838 | 52,801 |
| 28 | (331) Structures and Improvements | 179,022,986 | 17,643,830 |
| 29 | (332) Reservoirs, Dams, and Waterways | 271,762,158 | 1,936,554 |
| 30 | (333) Water Wheels, Turbines, and Generators | 241,657,341 | 18,996,026 |
| 31 | (334) Accessory Electric Equipment | 60,377,085 | 2,145,400 |
| 32 | (335) Misc. Power PLant Equipment | 24,514,473 | 1,521,010 |
| 33 | (336) Roads, Railroads, and Bridges | 10,842,584 | 39,099 |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | | |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | 819,621,465 | 42,334,720 |
| 36 | D. Other Production Plant | | |
| 37 | (340) Land and Land Rights | 2,690,006 | |
| 38 | (341) Structures and Improvements | 143,167,990 | 364,784 |
| 39 | (342) Fuel Holders, Products, and Accessories | 10,452,547 | 85,022 |
| 40 | (343) Prime Movers | 229,873,752 | 9,328,517 |
| 41 | (344) Generators | 66,531,876 | |
| 42 | (345) Accessory Electric Equipment | 91,146,851 | 331,510 |
| 43 | (346) Misc. Power Plant Equipment | 6,240,366 | 148,347 |
| 44 | (347) Asset Retirement Costs for Other Production | | |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | 550,103,388 | 10,258,180 |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45) | 2,551,823,292 | 71,998,946 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

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

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

| Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | 5,703 | | 2 |
| 60,000 | | | 30,669,683 | | 3 |
| 3,640,095 | | | 26,616,961 | | 4 |
| 3,700,095 | | | 57,292,347 | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| | | | 1,722,421 | | 8 |
| 237,952 | | | 154,463,765 | | 9 |
| 6,322,569 | | | 757,671,126 | | 10 |
| | | | | | 11 |
| 874,372 | | | 169,859,625 | | 12 |
| 282,041 | | | 73,750,009 | | 13 |
| 1,277,900 | | | 20,152,814 | | 14 |
| | | | 14,889,891 | | 15 |
| 8,994,834 | | | 1,192,509,651 | | 16 |
| | | | | | 17 |
| | | | | | 18 |
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| | | | | | 22 |
| | | | | | 23 |
| | | | | | 24 |
| | | | | | 25 |
| | | | | | 26 |
| | | | 31,497,639 | | 27 |
| 424,174 | | | 196,242,642 | | 28 |
| 153,429 | | | 273,545,283 | | 29 |
| 343,954 | | | 260,309,413 | | 30 |
| 57,618 | | | 62,464,867 | | 31 |
| 43,775 | | | 25,991,708 | | 32 |
| | | | 10,881,683 | | 33 |
| | | | | | 34 |
| 1,022,950 | | | 860,933,235 | | 35 |
| | | | | | 36 |
| | | | 2,690,006 | | 37 |
| 200,018 | | | 143,332,756 | | 38 |
| | | | 10,537,569 | | 39 |
| 14,664,440 | | | 224,537,829 | | 40 |
| | | | 66,531,876 | | 41 |
| | | | 91,478,361 | | 42 |
| | | | 6,388,713 | | 43 |
| | | | | | 44 |
| 14,864,458 | | | 545,497,110 | | 45 |
| 24,882,242 | | | 2,598,939,996 | | 46 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

| Line No. | Account<br>(a) | Balance Beginning of Year<br>(b) | Additions<br>(c) |
|---|---|---|---|
| 47 | 3. TRANSMISSION PLANT | | |
| 48 | (350) Land and Land Rights | 37,193,222 | 115,120 |
| 49 | (352) Structures and Improvements | 79,539,883 | 849,041 |
| 50 | (353) Station Equipment | 411,289,120 | 20,101,853 |
| 51 | (354) Towers and Fixtures | 198,102,599 | 8,760,019 |
| 52 | (355) Poles and Fixtures | 175,172,643 | 9,490,063 |
| 53 | (356) Overhead Conductors and Devices | 219,214,808 | 8,705,363 |
| 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) | 1,120,902,541 | 48,021,459 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 5,947,971 | 104,648 |
| 61 | (361) Structures and Improvements | 36,984,366 | 577,575 |
| 62 | (362) Station Equipment | 222,356,864 | 17,225,163 |
| 63 | (363) Storage Battery Equipment | | |
| 64 | (364) Poles, Towers, and Fixtures | 256,158,912 | 11,240,685 |
| 65 | (365) Overhead Conductors and Devices | 131,275,340 | 6,400,542 |
| 66 | (366) Underground Conduit | 49,794,768 | 1,439,022 |
| 67 | (367) Underground Conductors and Devices | 243,650,263 | 16,625,202 |
| 68 | (368) Line Transformers | 536,550,475 | 30,689,434 |
| 69 | (369) Services | 59,471,387 | 1,720,471 |
| 70 | (370) Meters | 87,259,555 | 5,341,004 |
| 71 | (371) Installations on Customer Premises | 3,016,977 | 86,705 |
| 72 | (372) Leased Property on Customer Premises | | |
| 73 | (373) Street Lighting and Signal Systems | 4,500,453 | 64,475 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | 164,191 | -21,561 |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 1,637,131,522 | 91,493,365 |
| 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 | 17,175,955 | 285,509 |
| 87 | (390) Structures and Improvements | 118,449,353 | 3,055,224 |
| 88 | (391) Office Furniture and Equipment | 49,081,870 | 4,978,442 |
| 89 | (392) Transportation Equipment | 81,429,700 | 10,945,622 |
| 90 | (393) Stores Equipment | 2,619,997 | 365,494 |
| 91 | (394) Tools, Shop and Garage Equipment | 8,666,166 | 1,827,995 |
| 92 | (395) Laboratory Equipment | 13,022,365 | 1,179,313 |
| 93 | (396) Power Operated Equipment | 15,085,037 | 1,248,738 |
| 94 | (397) Communication Equipment | 56,593,212 | 951,803 |
| 95 | (398) Miscellaneous Equipment | 6,571,337 | 713,112 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 368,694,992 | 25,551,252 |
| 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) | 368,694,992 | 25,551,252 |
| 100 | TOTAL (Accounts 101 and 106) | 5,731,292,950 | 245,316,861 |
| 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) | 5,731,292,950 | 245,316,861 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

| Retirements<br>(d) | Adjustments<br>(e) | Transfers<br>(f) | Balance at End of Year<br>(g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 47 |
| 180,896 | | | 37,127,446 | | 48 |
| 125,307 | | | 80,263,617 | | 49 |
| 2,441,304 | | | 428,949,669 | | 50 |
| 309,889 | | | 206,552,729 | | 51 |
| 1,327,049 | | | 183,335,657 | | 52 |
| 1,299,065 | | | 226,621,106 | | 53 |
| | | | | | 54 |
| | | | | | 55 |
| | | | 390,266 | | 56 |
| | | | | | 57 |
| 5,683,510 | | | 1,163,240,490 | | 58 |
| | | | | | 59 |
| | | | 6,052,619 | | 60 |
| 98,568 | | | 37,463,373 | | 61 |
| 2,249,918 | | | 237,332,109 | | 62 |
| | | | | | 63 |
| 2,018,214 | | | 265,381,383 | | 64 |
| 1,605,944 | | | 136,069,938 | | 65 |
| 474,720 | | | 50,759,070 | | 66 |
| 1,775,711 | | | 258,499,754 | | 67 |
| 7,206,081 | | | 560,033,828 | | 68 |
| 405,790 | | | 60,786,068 | | 69 |
| 2,579,391 | | | 90,021,168 | | 70 |
| 46,326 | | | 3,057,356 | | 71 |
| | | | | | 72 |
| 38,007 | | | 4,526,921 | | 73 |
| | | | 142,630 | | 74 |
| 18,498,670 | | | 1,710,126,217 | | 75 |
| | | | | | 76 |
| | | | | | 77 |
| | | | | | 78 |
| | | | | | 79 |
| | | | | | 80 |
| | | | | | 81 |
| | | | | | 82 |
| | | | | | 83 |
| | | | | | 84 |
| | | | | | 85 |
| | | | 17,461,464 | | 86 |
| 850,457 | | | 120,654,120 | | 87 |
| 9,147,780 | | | 44,912,532 | | 88 |
| 4,226,428 | | | 88,148,894 | | 89 |
| 37,844 | | | 2,947,647 | | 90 |
| 55,997 | | | 10,438,164 | | 91 |
| 332,616 | | | 13,869,062 | | 92 |
| 68,496 | | | 16,265,279 | | 93 |
| 3,409,266 | | | 54,135,749 | | 94 |
| 305,349 | | | 6,979,100 | | 95 |
| 18,434,233 | | | 375,812,011 | | 96 |
| | | | | | 97 |
| | | | | | 98 |
| 18,434,233 | | | 375,812,011 | | 99 |
| 71,198,750 | | | 5,905,411,061 | | 100 |
| | | | | | 101 |
| | | | | | 102 |
| | | | | | 103 |
| 71,198,750 | | | 5,905,411,061 | | 104 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 2018 | 763,161 |
| 3 | Production | | | 109,961 |
| 4 | Transmission Stations | | | 423,089 |
| 5 | Transmission Lines | | | 195,489 |
| 6 | Distribution Stations | | | 1,083,432 |
| 7 | Beacon Light Substation | 12/30/02 | 2020 | 465,662 |
| 8 | Homedale Substation | 2/29/08 | 2035 | 109,453 |
| 9 | North River Operations Center | 1/31/08 | 2019 | 2,630,412 |
| 10 | Line #854 500 Kv | 3/31/09 | 2024 | 308,066 |
| 11 | General Plant | | | 62,673 |
| 12 | | | | |
| 13 | | | | |
| 14 | Column B and C if no date listed it is various | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |
| 21 | Other Property: | | | |
| 22 | Boise Operations Center | 7/01/2016 | 2018 | 437,243 |
| 23 | Transmission Stations | | | 199,069 |
| 24 | Distribution Stations | | | 69,941 |
| 25 | Homedale Substation | 2/29/08 | 2035 | 217,797 |
| 26 | Beacon Light Substation | 12/30/02 | 2020 | 555,940 |
| 27 | Underground Vault, Blaine County | 8/30/16 | 2020 | 443,545 |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | Column B and C if no date listed it is various | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
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| 37 | | | | |
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| 43 | | | | |
| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | Total | | | 8,074,933 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | ROLLUP RELIC COST BROWNLEE | 104,801,174 |
| 2 | ROLLUP RELIC COST HELLS CANYON | 71,364,431 |
| 3 | GATEWAY WEST 500KV LINE | 35,041,686 |
| 4 | ROLLUP RELIC COST OXBOW | 33,196,024 |
| 5 | HELLS CANYON RELICENSING OUTSI | 29,075,023 |
| 6 | B2H PERMITTING 11/1/2011 & FOR | 15,604,221 |
| 7 | BOARDMAN - HEMINGWAY 500 KV LI | 8,635,201 |
| 8 | HCC WATERSHED ENHANCEMENT PROG | 6,653,967 |
| 9 | BROWNLEE UNIT 4 TURBINE REFURB | 5,851,982 |
| 10 | BLISS UNIT 3 TURBINE REBURBISH | 5,731,782 |
| 11 | BROWNLEE UNIT 2 TURBINE REFURB | 4,783,347 |
| 12 | LEGAL DEPT. LABOR FOR RELICENS | 4,684,762 |
| 13 | 2-WAY RADIO - BVMT - BEAVER MO | 4,510,345 |
| 14 | BAYHA ISLAND RESEARCH PROJECT | 4,260,758 |
| 15 | WQ HCC401 CERTIFICATION OPS AN | 4,022,081 |
| 16 | EIM INTEGRATION | 3,966,194 |
| 17 | BUILD CADA SUBSTATION | 3,806,807 |
| 18 | UPPER MALAD FISH LADDER | 3,431,906 |
| 19 | REL-HCC OREGON REAUTHORIZATION | 3,381,049 |
| 20 | NEWX110100 STAR-LNSG NEW 138 K | 3,232,240 |
| 21 | B2H TLINE CONSTRUCTION COSTS | 2,916,262 |
| 22 | LNSG0703 ADD LINE TERMINALS CO | 2,780,932 |
| 23 | BLISS UNIT 3 GENERATOR REWIND | 2,780,593 |
| 24 | METEOROLOGY MODEL FOR OPERATIO | 2,512,135 |
| 25 | FAREWELL BEND STATE PARK BANK | 2,364,097 |
| 26 | BULL TROUT PROGRAM - ADMINISTR | 2,321,667 |
| 27 | WDRI-KCHM NEW 138KV | 2,223,012 |
| 28 | 700MHZ SPECTRUM PURCHASE | 2,186,989 |
| 29 | WQ HCC401 APPLICATION, REVISIO | 2,109,063 |
| 30 | FALL CHINOOK PROGRAM - REDD SU | 2,025,573 |
| 31 | GRAND VIEW IRRIGATION UPGRADE | 1,832,077 |
| 32 | LTP - HOT GAS PATH INSPECTION | 1,830,306 |
| 33 | HBND-041:ALT LINE ROUTE TO GAR | 1,779,510 |
| 34 | SHOSHONE FALLS UPGRADE - REPLA | 1,718,930 |
| 35 | THOUSAND SPRINGS UNIT 3 ROTOR | 1,534,178 |
| 36 | HCC RELICENSING WATER QUALITY | 1,522,985 |
| 37 | BUILD CADA-011 | 1,343,748 |
| 38 | 220MHZ SPECTRUM PURCHASE | 1,314,934 |
| 39 | T40401 - RECONSTRUCT/BUILD NEW | 1,289,718 |
| 40 | CHQ REMODEL | 1,243,349 |
| 41 | HTSU110001 - REPLACE MLNR-PAUL | 1,217,312 |
| 42 | LANGLEY WATER AND WASTEWATER B | 1,157,638 |
| 43 | TOTAL | 452,424,340 |

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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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | MAINSTEM FLOW AND TEMPERATURE | 1,126,513 |
| 2 | Other Minor Projects Under 1,000,000 | 53,257,839 |
| 3 | | |
| 4 | | |
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| 35 | | |
| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | TOTAL | 452,424,340 |

## 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 | 2,150,749,270 | 2,150,749,270 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 153,958,586 | 153,958,586 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | 566,665 | 566,665 | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | | | | |
| 6 | Transportation Expenses-Clearing | 4,298,853 | 4,298,853 | | |
| 7 | Other Clearing Accounts | | | | |
| 8 | Other Accounts (Specify, details in footnote): | | | | |
| 9 | Fuel Stock | 136,110 | 136,110 | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 158,960,214 | 158,960,214 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 67,498,655 | 67,498,655 | | |
| 13 | Cost of Removal | 17,944,114 | 17,944,114 | | |
| 14 | Salvage (Credit) | 3,113,452 | 3,113,452 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 82,329,317 | 82,329,317 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | 28,973,987 | 28,973,987 | | |
| 17 | | | | | |
| 18 | Book Cost or Asset Retirement Costs Retired | | | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 2,256,354,154 | 2,256,354,154 | | |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | 617,122,624 | 617,122,624 | | |
| 21 | Nuclear Production | | | | |
| 22 | Hydraulic Production-Conventional | 424,890,849 | 424,890,849 | | |
| 23 | Hydraulic Production-Pumped Storage | | | | |
| 24 | Other Production | 105,656,778 | 105,656,778 | | |
| 25 | Transmission | 364,308,753 | 364,308,753 | | |
| 26 | Distribution | 628,829,047 | 628,829,047 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 115,546,103 | 115,546,103 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 2,256,354,154 | 2,256,354,154 | | |
| | | | | | |

***Schedule Page: 219 Line No.: 16 Column: c***

Includes: Valmy depreciation adjustments (ID 33771 and OR 17-235), CIAC and Asset Retirement Obligation activity.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

| Line No. | Description of Investment (a) | Date Acquired (b) | Date Of Maturity (c) | Amount of Investment at Beginning of Year (d) |
|---|---|---|---|---|
| 1 | Idaho Energy Resources Company | | | |
| 2 | Common Stock | 02/01/74 | | 500 |
| 3 | Capital contributions | | | 2,462,594 |
| 4 | Equity in earnings | | | 74,667,833 |
| 5 | | | | |
| 6 | Subtotal Idaho Energy Resources Company | | | 77,130,927 |
| 7 | | | | |
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| 41 | | | | |
| 42 | Total Cost of Account 123.1 $ 2,463,094 | | TOTAL | 77,130,927 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 |
| 7,082,051 | 12,000,000 | 69,749,884 | | 4 |
| | | | | 5 |
| 7,082,051 | 12,000,000 | 72,212,978 | | 6 |
| | | | | 7 |
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| | | | | 41 |
| 7,082,051 | 12,000,000 | 72,212,978 | | 42 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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) | 53,700,442 | 56,638,459 | Electric |
| 2 | Fuel Stock Expenses Undistributed (Account 152) | -2,623 | 5 | 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) | 17,442,341 | 17,946,659 | |
| 8 | Transmission Plant (Estimated) | 13,353,307 | 10,011,948 | |
| 9 | Distribution Plant (Estimated) | 21,236,284 | 24,559,578 | |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 2,422,752 | 1,338,445 | |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 54,454,684 | 53,856,630 | Electric |
| 13 | Merchandise (Account 155) | | | |
| 14 | Other Materials and Supplies (Account 156) | | | |
| 15 | Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util) | | | |
| 16 | Stores Expense Undistributed (Account 163) | 3,403,797 | 1,888,307 | Electric |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | 111,556,300 | 112,383,401 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## Transmission Service and Generation Interconnection Study Costs

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

| Line No. | Description (a) | Costs Incurred During Period (b) | Account Charged (c) | Reimbursements Received During the Period (d) | Account Credited With Reimbursement (e) |
|---|---|---|---|---|---|
| 1 | **Transmission Studies** | | | | |
| 2 | BPAP NETWORK SIS 83177020 | 1,017 | 186623 | 2,988 | 186623 |
| 3 | | | | | |
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| 20 | | | | | |
| 21 | **Generation Studies** | | | | |
| 22 | JACKPOT SOLAR SOUTH #503 | 13,279 | 186623 | 634 | 186623 |
| 23 | SOUTHERN IDAHO SOLID WASTE #501 | | 186623 | 28,436 | 186623 |
| 24 | BAKER CITY 1 SOLAR | 4,627 | 186623 | ( 30,000) | 186623 |
| 25 | JACKPOT ANNEX SOLAR #523 | 16,318 | 186623 | ( 16,318) | 186623 |
| 26 | CAT CREEK PUMP STORAGE #524 | 17,861 | 186623 | ( 10,000) | 186623 |
| 27 | IPCO COMMUNITY SOLAR #509 | | 186623 | | 186623 |
| 28 | ONTARIO SOLAR #525 | 1,445 | 186623 | ( 10,000) | 186623 |
| 29 | WARM SPRINGS HYDRO #526 | 2,017 | 186623 | ( 1,000) | 186623 |
| 30 | BRUSH SOLAR #512 | | 186623 | 26,742 | 186623 |
| 31 | CARTER SOLAR #517 | 114 | 186623 | ( 1,382) | 186623 |
| 32 | JACKPOT SOLAR EAST #514 | | 186623 | 27,886 | 186623 |
| 33 | JACKPOT SOLAR NORTH #502 | | 186623 | 9,528 | 186623 |
| 34 | JACKPOT SOLAR WEST #513 | | 186623 | 27,993 | 186623 |
| 35 | MORGAN SOLAR #510 | 976 | 186623 | 29,024 | 186623 |
| 36 | ONTARIO 1 SOLAR #520 | 2,460 | 186623 | ( 2,460) | 186623 |
| 37 | SHOSHONE FALLS HYDRO PROJECT IPCO | 2,839 | 186623 | | 186623 |
| 38 | VALE 1 SOLAR #511 | | | 26,395 | 186623 |
| 39 | | | | | |
| 40 | | | | | |

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***Schedule Page: 231 Line No.: 2 Column: d***

Amounts in column D represent both reimbursements received (credit amounts) and refunds back to the counterparties (debit amounts). Refunds are initiated when the initial deposit exceeds the final expenses.

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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 | Fixed Cost Adjustment (FCA) (182302) | 34,867,487 | 15,542,127 | 400/1823 | 34,867,487 | 15,542,127 |
| 2 | Order #33527 (Amort period 06/17 thru 05/18) | | | | | |
| 3 | | | | | | |
| 4 | AOCI Impact of Unfunded Post Retirement Liability | 49,369 | 3,043,410 | 2283 | 47,258 | 3,045,521 |
| 5 | Order #30256 (182306) | | | | | |
| 6 | | | | | | |
| 7 | FCA Calender Mo Adjustment | ( 3,393,382) | 3,393,382 | 400 | 704,075 | -704,075 |
| 8 | Order #33295 (182308) | | | | | |
| 9 | | | | | | |
| 10 | Prior Year FCA - Order #33527 (182309) | 12,971,026 | 35,012,042 | 400 | 31,965,224 | 16,017,844 |
| 11 | (Amort period 06/16 thru 05/17) Order #33527 | | | | | |
| 12 | (Amort period 06/17 thru 05/18) Order #33777 | | | | | |
| 13 | | | | | | |
| 14 | PCA Unbilled Amortization (182316) | ( 1,987,454) | 848,564 | 400/401 | 207,938 | -1,346,828 |
| 15 | (Amort period 06/16 thru 05/17) | | | | | |
| 16 | | | | | | |
| 17 | AOCI Impact of Unfunded Pension Liability | 263,729,952 | 26,721,785 | 2283 | 13,331,245 | 277,120,492 |
| 18 | Order #30256 (182320) | | | | | |
| 19 | | | | | | |
| 20 | Deferred Pension Expense Net of Contributions | 22,295,429 | 39,250,908 | Various | 38,513,416 | 23,032,921 |
| 21 | Order #30333 (182321) | | | | | |
| 22 | | | | | | |
| 23 | FAS 109 Unfunded (182322) | 948,539,822 | | NA | 626,279,537 | 322,260,285 |
| 24 | Accum Deferred Income Noncurrent | | | | | |
| 25 | | | | | | |
| 26 | PCA Deferral Idaho - Order #33526 | 52,989,142 | | | 52,989,142 | |
| 27 | (Amort period 06/17 thru 05/18) (182323) | | | | | |
| 28 | | | | | | |
| 29 | PCA Prior Year Deferral Idaho - (182324) | 10,154,329 | 34,089,967 | Various | 39,761,505 | 4,482,791 |
| 30 | (Amort period 06/16 thru 05/17) Order #33526 | | | | | |
| 31 | (Amort period 06/17 thru 06/18) Order #33775 | | | | | |
| 32 | | | | | | |
| 33 | PCA Unbilled Forecast - Order #32821 (182325) | ( 3,027,410) | 3,027,410 | | | |
| 34 | | | | | | |
| 35 | PCA SBA Unbilled Adj-Order #33307 (182326) | ( 4,685,781) | 4,685,781 | | | |
| 36 | | | | | | |
| 37 | Idaho Pension Cash - Order #32248 (182327) | 83,056,919 | 38,913,176 | 401 | 17,281,662 | 104,688,433 |
| 38 | (Amort period beginning 06/11 thru indefinite) | | | | | |
| 39 | | | | | | |
| 40 | ASC 815 Mark to Market (182330 & 182333) | | 1,419,163 | 244 | | 1,419,163 |
| 41 | Order #28661 | | | | | |
| 42 | | | | | | |
| 43 | Oregon Pension Expense Capitalized (182339) | 3,756,774 | 757,277 | 401/4073 | 116,445 | 4,397,606 |
| | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Order #10-064 | | | | | |
| 2 | | | | | | |
| 3 | Asset Retirement Obligations (182341) | 13,970,846 | 1,658,624 | 401 | | 15,629,470 |
| 4 | IPUC Order #29414-OPUC Order #04-585 | | | | | |
| 5 | | | | | | |
| 6 | PCAM Oregon 2008 (182346) | 739,466 | 3,396 | 402 | 742,862 | |
| 7 | Order #08-238 & #13-439 (Amort 01/14 - 06/17) | | | | | |
| 8 | | | | | | |
| 9 | 2008 PCAM Unbilled Amort (182356) | ( 195,193) | 196,036 | 402 | | 843 |
| 10 | (Amort period 01/14 thru 06/17) | | | | | |
| 11 | | | | | | |
| 12 | RA-Hells Canyon-Baker Co-Order #33948 (182360) | | 3,085,321 | NA | | 3,085,321 |
| 13 | | | | | | |
| 14 | Lidar Surveys - Order #32426 (182361) | 218,023 | | 402 | 43,605 | 174,418 |
| 15 | (Amort period 01/12 thru 12/21) | | | | | |
| 16 | | | | | | |
| 17 | PS&I Shoshone - Order #29904 (182368) | 400,187 | | 402 | 266,791 | 133,396 |
| 18 | (Amort period 07/15 thru 06/18) | | | | | |
| 19 | | | | | | |
| 20 | RA-EIM Deferral-Order #33706 (182370) | | 786,074 | 107/999 | | 786,074 |
| 21 | | | | | | |
| 22 | RA-Intervenor Funding-Idaho (182387) | | 150,754 | NA | | 150,754 |
| 23 | | | | | | |
| 24 | RA-CONTRA-DEF INC TAX (182389) | | 262,069,157 | 282 | | 262,069,157 |
| 25 | | | | | | |
| 26 | Idaho Boardman ARO - Order #29414 (182393) | 174,226 | | 4031/4110 | 43,557 | 130,669 |
| 27 | (Amort period thru 2020) | | | | | |
| 28 | | | | | | |
| 29 | Langley Revenue Accrual - Order #12-226 (182398) | 1,098,946 | 88,049 | NA | | 1,186,995 |
| 30 | | | | | | |
| 31 | RA-OR Langley Rev Int Res (182399) | ( 95,418) | | 4210 | 30,282 | -125,700 |
| 32 | | | | | | |
| 33 | Siemens Long Term Deferred Rate Base (182410) | 11,201,419 | | 4073 | 431,488 | 10,769,931 |
| 34 | Order #33420 (Amort period 01/16 thru 12/42) | | | | | |
| 35 | | | | | | |
| 36 | Siemens Long Term Deferred Rate Base (182411) | 16,714,770 | | 4073 | 643,866 | 16,070,904 |
| 37 | Order #33420 (Amort period 01/16 thru 12/42) | | | | | |
| 38 | | | | | | |
| 39 | Siemens Long Term Deferred Rate Base (182412) | 441,774 | 33,717 | Various | 48,843 | 426,648 |
| 40 | Order #15-387 (Amort period 01/16 thru 12/36) | | | | | |
| 41 | | | | | | |
| 42 | Siemens Long Term Deferred Rate Base (182413) | 757,149 | | 4073 | 49,465 | 707,684 |
| 43 | Order #15-387 (Amort period 01/16 thru 12/36) | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter /Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | RA-Valmy O&M ID 33771 (182432) | | | 400/1823 | 738,442 | -738,442 |
| 3 | | | | | | |
| 4 | RA-Valmy OR Depr Adj 17-325 (182434) | | 1,281,969 | NA | | 1,281,969 |
| 5 | (Amort period 06/17 thru 12/25) | | | | | |
| 6 | | | | | | |
| 7 | RA-Valmy Acctg Adj ID 33771 (182435) | | 44,107,596 | NA | | 44,107,596 |
| 8 | | | | | | |
| 9 | Idaho Boardman Decomissioning (182493) | 1,471,285 | 5,833,697 | Various | 7,304,982 | |
| 10 | Order #32549 & #32457 | | | | | |
| 11 | | | | | | |
| 12 | RA-OR BDMN DECOM 12 235 (182494) | ( 18,415) | 18,415 | | | |
| 13 | | | | | | |
| 14 | Oregon DSM Rider (182405) | 5,552,141 | 2,329,344 | | 1,608,956 | 6,272,529 |
| 15 | Advise 05-03 | | | | | |
| 16 | | | | | | |
| 17 | Minor Items (25) | 192,973 | 1,392,121 | Various | 1,565,396 | 19,698 |
| 18 | | | | | | |
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| 43 | | | | | | |
| 44 | **TOTAL :** | 1,471,940,401 | 529,739,262 | | 869,583,469 | 1,132,096,194 |

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 Credit Facility(186025) | 1,023,246 | | 431,232 | 14,284 | 1,008,962 |
| 2 | (Amort period 11/16 thru 11/20) | | | | | |
| 3 | | | | | | |
| 4 | Prepaid Service Contract | 2,188,196 | 999,315 | | | 3,187,511 |
| 5 | Long Term Portion (186052) | | | | | |
| 6 | | | | | | |
| 7 | Long Term (186121) | 1,041,877 | | 401,2282 | 21,813 | 1,020,064 |
| 8 | Workers Compensation | | | | | |
| 9 | | | | | | |
| 10 | Prepaid ROW (186160) | 339,887 | 329,490 | | | 669,377 |
| 11 | Rents/Easements Long Term | | | | | |
| 12 | | | | | | |
| 13 | Long-Term Portfolio (186255) | 465,469 | 90,142 | 401 | 465,469 | 90,142 |
| 14 | | | | | | |
| 15 | Advance Prepaid (186709) | 1,088,440 | | 151 | 81,052 | 1,007,388 |
| 16 | Coal Royalties | | | | | |
| 17 | | | | | | |
| 18 | Stable Value Life (186719) | 41,422,609 | 1,736,828 | | | 43,159,437 |
| 19 | | | | | | |
| 20 | Security Plan (186720) | 12,376,573 | | 143,4262 | 102,125 | 12,274,448 |
| 21 | Net Insurance Asset | | | | | |
| 22 | | | | | | |
| 23 | American Falls Bond Ref(186722) | 118,843 | | 401 | 14,552 | 104,291 |
| 24 | (Amort Period 04/00 thru 02/25) | | | | | |
| 25 | | | | | | |
| 26 | Retiree Medical-COLI (186726) | 3,753,976 | 135,081 | | | 3,889,057 |
| 27 | | | | | | |
| 28 | American Falls Water Rights | 8,422,904 | | 401 | 1,042,009 | 7,380,895 |
| 29 | (Amort 01/06 - 02/25) (186727) | | | | | |
| 30 | | | | | | |
| 31 | Shelf Registration (186733) | 147,328 | | | | 147,328 |
| 32 | | | | | | |
| 33 | Milner Bond Guarantee (186734) | 1,063,636 | | 253 | 1,063,636 | |
| 34 | (Amort 02/07 - 2/17) | | | | | |
| 35 | | | | | | |
| 36 | American Falls - Bond Refinance | 391,993 | | 401 | 47,999 | 343,994 |
| 37 | (Amort through 02/25) (186770) | | | | | |
| 38 | | | | | | |
| 39 | Bridger Coal Study (186781) | 1,472,259 | 112,977 | | | 1,585,236 |
| 40 | | | | | | |
| 41 | Miscellaneous Deferred Debt | | | Various | 2,772,230 | -2,772,230 |
| 42 | Regulatory Reserves (186800) | | | | | |
| 43 | | | | | | |
| 44 | Minor Items (3) | 15,421 | 207,246 | Various | 185,879 | 36,788 |
| 45 | | | | | | |
| 46 | | | | | | |
| 47 | Misc. Work in Progress | | | | | |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 75,332,657 | | | | 73,132,688 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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) | 92,773,039 | 89,557,247 |
| 6 | | | |
| 7 | Other (See footnote) | 168,030,701 | 182,469,703 |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 260,803,740 | 272,026,950 |
| 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) | 25,522,789 | 17,786,969 |
| 18 | TOTAL (Acct 190) (Total of lines 8, 16 and 17) | 286,326,529 | 289,813,919 |

Notes

**Schedule Page: 234 Line No.: 5 Column: c**

| | Beginning Balance | Ending Balance |
|---|---|---|
| Construction Advances | 1,838,458 | 1,420,074 |
| Postretirement Benefits | 566,112 | 436,208 |
| USBR-American Falls O&M Costs Settlement | 125,256 | 74,148 |
| Non-VEBA Pension and Benefits | (179,497) | (238,565) |
| Executive Deferred Compensation | 39,761 | 28,808 |
| Retention Pay Accrual | 22,212 | 21,449 |
| Stock Based Compensation | 3,861,627 | 3,209,060 |
| Pension Expense-Oregon | 3,523,081 | 2,714,789 |
| Bridger Revenue Deferral | 442,426 | 377,040 |
| Asset Retirement Obligation (ARO) | 1,543,332 | 1,230,333 |
| Incentive Deferral-Profit Sharing-Not in Rates | 4,939,496 | 3,752,926 |
| OR Reconnect Fees Adv | 0 | 237 |
| Rate Case Disallowance | 2,157,902 | 1,356,867 |
| Prov for Rate Refund-HC Relicensing (AFUDC) | 40,353,531 | 31,085,864 |
| Revenue Sharing | 0 | 0 |
| VEBA-Post Retirement Benefits | 11,747,529 | 7,854,162 |
| Deferred Idaho ITC | 21,721,941 | 29,195,228 |
| Deferred GBC Federal | 69,872 | 7,038,619 |
| Total Other Electric | 92,773,039 | 89,557,247 |

**Schedule Page: 234 Line No.: 7 Column: c**

| | | |
|---|---|---|
| Pension-FAS 158 | 103,332,880 | 72,068,421 |
| Regulatory Liability-FAS 109 | 51,326,330 | 98,743,759 |
| Minimum Pension Liability | 13,403,940 | 10,866,388 |
| Postretirement Plan-FAS 158 | (32,449) | 791,135 |
| Total Other | 168,030,701 | 182,469,703 |

**Schedule Page: 234 Line No.: 17 Column: c**

| | | |
|---|---|---|
| Senior Management Security Plan | 25,522,789 | 17,786,969 |
| Total Non Electric | 25,522,789 | 17,786,969 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

| OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent) | | HELD BY RESPONDENT | | | | Line No. |
|---|---|---|---|---|---|---|
| | | AS REACQUIRED STOCK (Account 217) | | IN SINKING AND OTHER FUNDS | | |
| Shares (e) | Amount (f) | Shares (g) | Cost (h) | Shares (i) | Amount (j) | |
| | | | | | | 1 |
| 39,150,812 | 97,877,030 | | | | | 2 |
| | | | | | | 3 |
| 39,150,812 | 97,877,030 | | | | | 4 |
| | | | | | | 5 |
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## OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

| Line No. | Item (a) | Amount (b) |
|---|---|---|
| 1 | Account 208 - Donations received from stockholders - None | |
| 2 | | |
| 3 | Account 209 - Reduction in par or stated value of Capital Stock - None | |
| 4 | | |
| 5 | Account 210 - Gain on reacquired Capital Stock - None | |
| 6 | | |
| 7 | | |
| 8 | Account 211 - Miscellaneous paid-in Capital - None | |
| 9 | | |
| 10 | | |
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| 12 | | |
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| 35 | | |
| 36 | | |
| 37 | | |
| 38 | | |
| 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## CAPITAL STOCK EXPENSE (Account 214)

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

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

| Line No. | Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a) | Principal Amount Of Debt issued (b) | Total expense, Premium or Discount (c) |
|---|---|---|---|
| 1 | Account 221: | | |
| 2 | First Mortgage Bonds: | | |
| 3 | 4.50% Series due 2020 | 130,000,000 | 1,190,698 |
| 4 | | | 234,601 D |
| 5 | | | |
| 6 | 5.50% Series due 2033 | 70,000,000 | 728,701 |
| 7 | | | 36,400 D |
| 8 | | | |
| 9 | 3.40% Series due 2020 | 100,000,000 | 1,159,871 |
| 10 | | | 498,864 D |
| 11 | | | |
| 12 | 5.30% Series Due 2035 | 60,000,000 | 408,411 D |
| 13 | | | 3,802,019 |
| 14 | | | |
| 15 | 4.00% Series due 2043 | 75,000,000 | 742,017 |
| 16 | | | 193,836 D |
| 17 | | | |
| 18 | 6.00% Series due 2032 | 100,000,000 | 1,191,216 |
| 19 | | | 543,244 D |
| 20 | | | |
| 21 | 5.875% Series due 2034 | 55,000,000 | -585,759 |
| 22 | | | 746,961 D |
| 23 | | | |
| 24 | 5.50% Series due 2034 | 50,000,000 | 524,419 |
| 25 | | | 383,322 D |
| 26 | | | |
| 27 | 4.85% Series Due 2040 | 100,000,000 | 1,284,871 |
| 28 | | | 169,984 D |
| 29 | | | |
| 30 | 6.30% Series due 2037 | 140,000,000 | 1,495,799 |
| 31 | | | 278,367 D |
| 32 | | | |
| 33 | TOTAL | 1,777,045,000 | 29,952,899 |

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 |
| 11/1/10 | 5/1/2020 | 11/1/10 | 5/1/20 | 100,000,000 | 3,400,000 | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| 08/26/05 | 08/26/35 | 08/26/05 | 08/26/35 | 60,000,000 | 3,180,000 | 12 |
| | | | | | | 13 |
| | | | | | | 14 |
| 4/8/2013 | 4/1/2043 | 4/8/2013 | 4/1/2043 | 75,000,000 | 3,000,000 | 15 |
| | | | | | | 16 |
| | | | | | | 17 |
| 11/15/02 | 11/15/32 | 11/15/02 | 11/15/32 | 100,000,000 | 6,000,000 | 18 |
| | | | | | | 19 |
| | | | | | | 20 |
| 08/16/04 | 08/16/34 | 08/16/04 | 08/16/34 | 55,000,000 | 3,231,250 | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| 03/26/04 | 03/15/34 | 03/26/04 | 03/15/34 | 50,000,000 | 2,750,000 | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| 2/15/10 | 8/15/40 | 2/15/10 | 8/15/40 | 100,000,000 | 4,850,000 | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| 6/22/07 | 6/15/2037 | 6/22/07 | 6/15/37 | 140,000,000 | 8,820,000 | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 1,765,345,000 | 81,198,430 | 33 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 6.25% Series due 2037 | 100,000,000 | 1,141,489 |
| 2 | | | 267,677 D |
| 3 | | | |
| 4 | Port of Morrow Variable due 2027 | 4,360,000 | 188,545 |
| 5 | | | |
| 6 | Humboldt Variable due 2024 | 49,800,000 | 1,697,856 |
| 7 | | | |
| 8 | Sweetwater Variable due 2026 | 116,300,000 | 3,026,122 |
| 9 | | | |
| 10 | 2.50% Series due 2023 | 75,000,000 | 648,267 |
| 11 | | | 371,854 D |
| 12 | | | |
| 13 | 4.30% Series Due 2042 | 75,000,000 | 802,240 |
| 14 | | | 49,417 D |
| 15 | | | |
| 16 | 2.95% Series Due 2022 | 75,000,000 | 708,490 |
| 17 | | | 127,607 D |
| 18 | | | |
| 19 | 3.65% Series Due 2045 | 250,000,000 | 2,559,510 |
| 20 | | | 1,715,000 D |
| 21 | | | |
| 22 | 4.05% Series Due 2046 | 120,000,000 | 1,311,383 |
| 23 | | | 309,600 D |
| 24 | | | |
| 25 | Subtotal Account 221 | 1,745,460,000 | 29,952,899 |
| 26 | | | |
| 27 | Account 222 - Reaquired Bonds | | |
| 28 | | | |
| 29 | Account 223: Advances for Associated Companies | | |
| 30 | | | |
| 31 | Account 224: | | |
| 32 | Bond Guarantee - American Falls | 19,885,000 | |
| 33 | TOTAL | 1,777,045,000 | 29,952,899 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|---|
| 10/18/07 | 10/15/2037 | 10/18/07 | 10/15/37 | 100,000,000 | 6,250,000 | 1 |
| | | | | | | 2 |
| | | | | | | 3 |
| 05/17/00 | 02/01/27 | 05/17/00 | 02/01/27 | 4,360,000 | 49,230 | 4 |
| | | | | | | 5 |
| 10/22/03 | 12/01/24 | 11/01/03 | 12/01/24 | 49,800,000 | 2,564,700 | 6 |
| | | | | | | 7 |
| 10/3/06 | 7/15/26 | 10/3/06 | 7/15/26 | 116,300,000 | 6,105,750 | 8 |
| | | | | | | 9 |
| 4/8/2013 | 4/1/2023 | 4/8/2013 | 4/1/2023 | 75,000,000 | 1,875,000 | 10 |
| | | | | | | 11 |
| | | | | | | 12 |
| 4/13/12 | 4/1/42 | 4/13/12 | 4/1/42 | 75,000,000 | 3,225,000 | 13 |
| | | | | | | 14 |
| | | | | | | 15 |
| 4/13/12 | 4/1/22 | 4/13/12 | 4/1/22 | 75,000,000 | 2,212,500 | 16 |
| | | | | | | 17 |
| | | | | | | 18 |
| 3/6/15 | 3/1/45 | 3/6/15 | 3/1/45 | 250,000,000 | 9,125,000 | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| 3/10/16 | 3/1/46 | 3/10/16 | 3/1/46 | 120,000,000 | 4,860,000 | 22 |
| | | | | | | 23 |
| | | | | | | 24 |
| | | | | 1,745,460,000 | 81,198,430 | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| 04/26/00 | 2/1/25 | | | 19,885,000 | | 32 |
| | | | | 1,765,345,000 | 81,198,430 | 33 |

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 | Note Guarantee - Milner Dam | 11,700,000 | |
| 2 | Subtotal Account 224 | 31,585,000 | |
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| 32 | | | |
| 33 | TOTAL | 1,777,045,000 | 29,952,899 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|---|
| 02/10/92 | | | | | | 1 |
| | | | | 19,885,000 | | 2 |
| | | | | | | 3 |
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| | | | | 1,765,345,000 | 81,198,430 | 33 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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) | 206,347,317 |
| 2 | | |
| 3 | | |
| 4 | Taxable Income Not Reported on Books | |
| 5 | | 13,454,189 |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | Deductions Recorded on Books Not Deducted for Return | |
| 10 | | 22,660,080 |
| 11 | | |
| 12 | | |
| 13 | | |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | | 17,495,493 |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | | 83,510,928 |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | Federal Tax Net Income | 141,555,165 |
| 28 | Show Computation of Tax: | |
| 29 | | 49,509,308 |
| 30 | | |
| 31 | | |
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**Schedule Page: 261 Line No.: 5 Column: b**

| | |
|---|---|
| 4005-AVOIDED COST | 4,322,425 |
| 4003-CONSTRUCTION ADVANCES | 1,509,519 |
| 4013-CIAC - TAXABLE - ACCT 107 | 5,878,808 |
| 4021-ENGINEERING FEES - TAXABLE - ACCT 107 | 377,721 |
| 4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES | 1,365,716 |
| **Total** | **13,454,189** |

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

| | |
|---|---|
| **Total Federal and State taxes deducted on books** | **48,994,755** |
| 5001-BAD DEBT EXPENSE | 1,060,493 |
| 5022-263A CAPITALIZED OVERHEADS | (32,000,000) |
| 5024-NON-DEDUCTIBLE MEALS | 500,000 |
| 5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES | (4,857,657) |
| 5010-POSTEMPLOYMENT BENEFITS | 231,167 |
| 5023-PENSION EXPENSE | (22,846,287) |
| 5025-MILNER FALLING WATER | (855,672) |
| 5035-PCA EXPENSE DEFERRAL | 53,442,826 |
| 5047-EXECUTIVE DEFERRED COMP | 0 |
| 5053-STOCK BASED COMPENSATION | 2,306,851 |
| 5058-FIXED COST ADJUSTMENT | 13,589,235 |
| 5060-OREGON - PCAM | 467,920 |
| 5061-PENSION EXPENSE - OREGON | 1,439,156 |
| 5067-ASSET RETIREMENT OBLIGATION (ARO) | 788,594 |
| 5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES | 1,825,137 |
| 5074-VALMY SETTLEMENT ADJUSTMENT | (42,960,129) |
| 5075-EIM DEFERRAL | (806,365) |
| 5501-SMSP - INSURANCE COSTS | (1,857,803) |
| 5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST | 0 |
| 5504-NON-DEDUCTIBLE POLITICAL EXPENSES | 1,009,892 |
| 5505-SMSP - NET | 3,187,967 |
| **Total** | **22,660,080** |

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

| | |
|---|---|
| 7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES | 7,082,051 |
| 7509-SMSP - INSURANCE PROCEEDS | 96,941 |
| 7502-ALLOWANCE FOR OFUDC | 20,784,392 |
| 7503-ALLOWANCE FOR BFUDC | 8,694,285 |
| 7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC) | (16,447,714) |
| 7012-REVENUE SHARING | 0 |
| 7013-LANGLEY REVENUE ACCRUAL | (2,714,462) |
| **Total** | **17,495,493** |

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

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| | |
|---|---|
| 5538-STOCK BASED COMP - STOCK | 3,665,013 |
| 8702-STOCK BASED COMP - DIVIDENDS | 573,294 |
| 8025-MANUFACTURING DEDUCTION | 7,478,875 |
| 8034-REMOVAL COSTS | 17,944,114 |
| 8042-GAIN/LOSS ON REACQUIRED DEBT | (2,152,952) |
| 8073-REPAIRS DEDUCTION | 82,000,000 |
| 8077-PREPAID INSURANCE & OTHER EXPENSES | 1,447,880 |
| 8001-VEBA - POST RETIREMENT BENEFITS | (624,614) |
| 8020-CONSERVATION EXPENSES | (680,287) |
| 8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107 | 1,900,000 |
| 8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107 | 2,200,000 |
| 8009-DEPR TIMING DIFF - OPERATING - FEDERAL | (42,501,323) |
| **STATE INCOME TAX DEDUCTED ON FEDERAL RETURN** | 12,260,928 |
| **Total** | **83,510,928** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | -19,939,467 | | 46,455,836 | 48,727,629 | |
| 3 | Social Security - (FOAB) | 441,915 | | 15,581,429 | 15,591,511 | |
| 4 | Unemployment | 37,862 | | 91,280 | 91,713 | |
| 5 | Subtotal Federal | -19,459,690 | | 62,128,545 | 64,410,853 | |
| 6 | | | | | | |
| 7 | State of Idaho: | | | | | |
| 8 | Income | -3,114,901 | | 9,883,487 | 11,101,390 | |
| 9 | Unemployment | 23,588 | | 306,536 | 307,348 | |
| 10 | Property | 9,595,802 | | 22,411,740 | 22,166,327 | |
| 11 | Non-Operating | 9,597 | | 18,246 | 18,799 | |
| 12 | kWh | 78,001 | | 1,950,669 | 1,923,636 | |
| 13 | Regulatory Commission | | | 2,665,964 | 2,665,764 | |
| 14 | Business License - Sho Ban | | | 150 | 150 | |
| 15 | Subtotal Idaho | 6,592,087 | | 37,236,792 | 38,183,414 | |
| 16 | | | | | | |
| 17 | State of Oregon | | | | | |
| 18 | Income | -248,478 | | 526,268 | 635,504 | |
| 19 | Unemployment | 2,912 | | 54,986 | 55,704 | |
| 20 | Property | | 1,591,161 | 3,288,877 | 3,393,596 | |
| 21 | Non-Operating Property | | 973 | 1,975 | 2,005 | |
| 22 | Regulatory Commission | | | 254,808 | 254,808 | |
| 23 | Franchise | 194,412 | | 859,928 | 857,183 | |
| 24 | Subtotal Oregon | -51,154 | 1,592,134 | 4,986,842 | 5,198,800 | |
| 25 | | | | | | |
| 26 | State of Montana: | | | | | |
| 27 | Property | 161,088 | | 359,207 | 340,839 | |
| 28 | Subtotal Montana | 161,088 | | 359,207 | 340,839 | |
| 29 | | | | | | |
| 30 | State of Nevada: | | | | | |
| 31 | Property | | 487,522 | 907,842 | 817,042 | |
| 32 | Subtotal Nevada | | 487,522 | 907,842 | 817,042 | |
| 33 | | | | | | |
| 34 | State of Wyoming | | | | | |
| 35 | Property | 796,727 | | 1,508,456 | 1,550,956 | |
| 36 | Corporate License | | | 4,429 | 4,429 | |
| 37 | Subtotal Wyoming | 796,727 | | 1,512,885 | 1,555,385 | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | -11,945,257 | 2,079,656 | 91,265,008 | 110,517,763 | -6,309 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

| BALANCE AT END OF YEAR | | DISTRIBUTION OF TAXES CHARGED | | | | Line No. |
|---|---|---|---|---|---|---|
| (Taxes accrued Account 236) (g) | Prepaid Taxes (Incl. in Account 165) (h) | Electric (Account 408.1, 409.1) (i) | Extraordinary Items (Account 409.3) (j) | Adjustments to Ret. Earnings (Account 439) (k) | Other (l) | |
| | | | | | | 1 |
| -22,211,260 | | 44,701,501 | | | 1,754,335 | 2 |
| 431,833 | | 15,581,429 | | | | 3 |
| 37,428 | | 91,280 | | | | 4 |
| -21,741,999 | | 60,374,210 | | | 1,754,335 | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| -4,332,804 | | 9,880,304 | | | 3,183 | 8 |
| 22,775 | | 306,536 | | | | 9 |
| 9,841,215 | | 22,410,720 | | | 1,020 | 10 |
| 9,044 | | | | | 18,246 | 11 |
| 105,033 | | 1,950,669 | | | | 12 |
| | | 2,665,964 | | | | 13 |
| | | 150 | | | | 14 |
| 5,645,263 | | 37,214,343 | | | 22,449 | 15 |
| | | | | | | 16 |
| | | | | | | 17 |
| -357,714 | | 526,162 | | | 106 | 18 |
| 2,194 | | 54,986 | | | | 19 |
| | 1,695,878 | 3,152,162 | | | 136,715 | 20 |
| | 1,002 | | | | 1,975 | 21 |
| | | 254,808 | | | | 22 |
| 197,157 | | 859,928 | | | | 23 |
| -158,363 | 1,696,880 | 4,848,046 | | | 138,796 | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| 179,456 | | 359,207 | | | | 27 |
| 179,456 | | 359,207 | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| | 415,074 | 907,842 | | | | 31 |
| | 415,074 | 907,842 | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| 754,229 | | 1,508,456 | | | | 35 |
| | | 4,429 | | | | 36 |
| 754,229 | | 1,512,885 | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |
| -15,156,342 | 2,111,954 | 89,348,997 | | | 1,916,011 | 41 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | State of Washington | | | | | |
| 2 | Property | 6,000 | | 15,201 | 10,201 | |
| 3 | Subtotal Washington | 6,000 | | 15,201 | 10,201 | |
| 4 | | | | | | |
| 5 | Other States Income | 9,723 | | 151,925 | 6,505 | |
| 6 | Canada GST Tax | -38 | | | -5,276 | -6,309 |
| 7 | Payroll Tax Credit | | | -16,034,231 | | |
| 8 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | -11,945,257 | 2,079,656 | 91,265,008 | 110,517,763 | -6,309 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

| BALANCE AT END OF YEAR | | DISTRIBUTION OF TAXES CHARGED | | | | Line No. |
|---|---|---|---|---|---|---|
| (Taxes accrued Account 236) (g) | Prepaid Taxes (Incl. in Account 165) (h) | Electric (Account 408.1, 409.1) (i) | Extraordinary Items (Account 409.3) (j) | Adjustments to Ret. Earnings (Account 439) (k) | Other (l) | |
| | | | | | | 1 |
| 11,000 | | 15,201 | | | | 2 |
| 11,000 | | 15,201 | | | | 3 |
| | | | | | | 4 |
| 155,143 | | 151,494 | | | 431 | 5 |
| -1,071 | | | | | | 6 |
| | | -16,034,231 | | | | 7 |
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| -15,156,342 | 2,111,954 | 89,348,997 | | | 1,916,011 | 41 |

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

```
Account 409.2       $    20,850
Account 409.1         1,733,485
                    -------------
Total               $ 1,754,335
```

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

```
Account 409.2       $     3,183
```

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

```
Account 107         $     1,020
```

**Schedule Page: 262 Line No.: 11 Column: l**

```
Account 408.2       $    18,246
```

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

```
Account 409.2       $       106
```

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

```
Account 107         $   136,715
```

**Schedule Page: 262 Line No.: 21 Column: l**

```
Account 408.2       $     1,975
```

**Schedule Page: 262.1 Line No.: 5 Column: l**

```
Account 409.2       $       431
```

**Schedule Page: 262.1 Line No.: 6 Column: f**

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

**Schedule Page: 262.1 Line No.: 7 Column: i**

This amount is an offset to lines 3, 4, 9, and 19. 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.

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

| Line No. | Account Subdivisions (a) | Balance at Beginning of Year (b) | Deferred for Year Account No. (c) | Deferred for Year Amount (d) | Allocations to Current Year's Income Account No. (e) | Allocations to Current Year's Income Amount (f) | Adjustments (g) |
|---|---|---|---|---|---|---|---|
| 1 | Electric Utility | | | | | | |
| 2 | 3% | | | | | | |
| 3 | 4% | 323,927 | | | | 46,347 | |
| 4 | 7% | | | | | | |
| 5 | 10% | 16,941,112 | | | | 1,694,967 | |
| 6 | Other-Federal | 1,109,766 | | 6,968,747 | | 23,580 | |
| 7 | Other-State | 61,585,040 | 411.4 | 3,537,615 | 411.4 | 1,316,575 | |
| 8 | TOTAL | 79,959,845 | | 10,506,362 | | 3,081,469 | |
| 9 | Other (List separately and show 3%, 4%, 7%, 10% and TOTAL) | | | | | | |
| 10 | 11% | 1,109,766 | | | | 23,580 | |
| 11 | 30% | | 411.4 | 6,968,747 | | | |
| 12 | Total Line No. 6 | 1,109,766 | | 6,968,747 | | 23,580 | |
| 13 | | | | | | | |
| 14 | | | | | | | |
| 15 | State of Idaho | 61,585,040 | 411.4 | 3,537,615 | 411.4 | 1,316,575 | |
| 16 | | | | | | | |
| 17 | | | | | | | |
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| 47 | | | | | | | |
| 48 | | | | | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

| Balance at End of Year<br>(h) | Average Period of Allocation to Income<br>(i) | ADJUSTMENT EXPLANATION | Line No. |
|---|---|---|---|
| | | | 1 |
| | | | 2 |
| 277,580 | 6.99 | | 3 |
| | | | 4 |
| 15,246,145 | 9.99 | | 5 |
| 8,054,933 | | | 6 |
| 63,806,080 | 46.78 | | 7 |
| 87,384,738 | | | 8 |
| | | | 9 |
| 1,086,186 | 47.06 | | 10 |
| 6,968,747 | | | 11 |
| 8,054,933 | | | 12 |
| | | | 13 |
| | | | 14 |
| 63,806,080 | | | 15 |
| | | | 16 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | Balance at Beginning of Year<br>(b) | DEBITS<br>Contra Account<br>(c) | DEBITS<br>Amount<br>(d) | Credits<br>(e) | Balance at End of Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Point to Point Trans Study(253201) | 1,847,225 | 235 | 46,787 | 46,787 | 1,847,225 |
| 2 | | | | | | |
| 3 | FTV (253202) | 2,066,666 | 400 | 400,000 | | 1,666,666 |
| 4 | (Amort Period Mar 1998-Feb 2023) | | | | | |
| 5 | | | | | | |
| 6 | Sho Ban Trans ROW (253480) | 172,500 | 242 | 15,000 | | 157,500 |
| 7 | (Amort Period Jan 2005-Dec 2027) | | | | | |
| 8 | | | | | | |
| 9 | Operations Accrual (253550) | 524,456 | 232, 401 | 134,922 | 48,750 | 438,284 |
| 10 | | | | | | |
| 11 | Milner Falling Water (253953) | 855,672 | 186 | 1,063,636 | 207,964 | |
| 12 | Amort Period (Feb 1992 - Feb 2017) | | | | | |
| 13 | | | | | | |
| 14 | Postretirement Benefits (253960) | 1,448,043 | 253 | 231,167 | | 1,216,876 |
| 15 | | | | | | |
| 16 | Directors Deferred Compensation | 3,560,669 | 401 | 468,695 | 327,745 | 3,419,719 |
| 17 | (253980-253999) | | | | | |
| 18 | | | | | | |
| 19 | Minor Items (1) 253042 | 4,111 | 401 | 35,275 | 31,164 | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | TOTAL | 10,479,342 | | 2,395,482 | 662,410 | 8,746,270 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(d) |
|---|---|---|---|---|
| 1 | Account 282 | | | |
| 2 | Electric | 495,355,902 | 2,219,648 | 3,213,738 |
| 3 | Gas | | | |
| 4 | Other | | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | 495,355,902 | 2,219,648 | 3,213,738 |
| 6 | Non-Operating Property | | | |
| 7 | Other - Regulatory Asset | 948,539,824 | | |
| 8 | Like Kind Exchange- Reclass No | 5,631,121 | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru | 1,449,526,847 | 2,219,648 | 3,213,738 |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | 1,243,389,941 | 2,063,142 | 3,210,502 |
| 12 | State Income Tax | 206,136,906 | 156,506 | 3,236 |
| 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 | 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 |
| | | 254967 | 193,991,452 | 282111 | 221,698 | 300,592,058 | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| | | | 193,991,452 | | 221,698 | 300,592,058 | 5 |
| | | | | | | | 6 |
| | | 182 | 364,210,382 | | | 584,329,442 | 7 |
| | | | | 282100 | -221,698 | 5,409,423 | 8 |
| | | | 558,201,834 | | | 890,330,923 | 9 |
| | | | | | | | 10 |
| | | 182/254 | 526,123,793 | | | 716,118,788 | 11 |
| | | 182 | 32,078,041 | | | 174,212,135 | 12 |
| | | | | | | | 13 |

NOTES (Continued)

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

| Account | 2017 | Changes during Year | | Adjustments Debits | | Adjustments Credits | | 2017 |
|---|---|---|---|---|---|---|---|---|
| | Beginning Balance | DR to 410.1 | CR to 411.1 | Acct. credited | Amount | Acct. debited | Amount | Ending Balance |
| (a) | b | c | d | g | h | i | j | k |
| Depreciation Timing Diff-Operating | 485,712,843 | 5,810,998 | 1,023,918 | | | | | 490,499,923 |
| Like Kind Exchange - Reclass Non-Rate Base | (5,631,121) | | | | | 282111 | 221,698 | (5,409,423) |
| Excess Deferred Tax on Depreciation (Reg Liab) | 0 | | | 254967 | 193,991,452 | | | (193,991,452) |
| CIAC-Taxable-Acct 107 | (3,391,459) | 2,182,516 | 2,057,582 | | | | | (3,266,525) |
| Engineering Fees-Taxable-Acct 107 | (562,142) | 277,752 | 132,238 | | | | | (416,628) |
| Software-Labor Costs Deducted-Acct 107 | 1,528,084 | 447,600 | | | | | | 1,975,684 |
| Intangible-Labor Costs Deducted-Acct 107 | 17,699,697 | (6,499,218) | | | | | | 11,200,479 |
| **TOTAL Line 2** | 495,355,902 | 2,219,648 | 3,213,738 | | 193,991,452 | | 221,698 | 300,592,058 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

| Line No. | Account (a) | Balance at Beginning of Year (b) | CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c) | CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d) |
|---|---|---|---|---|
| 1 | Account 283 | | | |
| 2 | Electric | | | |
| 3 | Other Electric -- See Note | 79,556,060 | 36,638,571 | 64,494,466 |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | Other -- See Note | 103,300,432 | | |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | 182,856,492 | 36,638,571 | 64,494,466 |
| 10 | Gas | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | TOTAL Gas (Total of lines 11 thru 16) | | | |
| 18 | Other -- See Note | -95,258 | | |
| 19 | TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18) | 182,761,234 | 36,638,571 | 64,494,466 |
| 20 | Classification of TOTAL | | | |
| 21 | Federal Income Tax | 153,310,006 | 32,269,243 | 59,843,443 |
| 22 | State Income Tax | 29,451,228 | 4,369,328 | 4,651,023 |
| 23 | Local Income Tax | | | |

NOTES

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

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

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | | |
|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | Balance at End of Year (k) | Line No. |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | 51,700,165 | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | -30,440,876 | 72,859,556 | 8 |
| | | | | | -30,440,876 | 124,559,721 | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| | | | | | | | 17 |
| 94,385 | 2,387 | | | | | -3,260 | 18 |
| 94,385 | 2,387 | | | | -30,440,876 | 124,556,461 | 19 |
| | | | | | | | 20 |
| 79,825 | 2,387 | | | | -31,464,494 | 94,348,750 | 21 |
| 14,560 | | | | | 1,023,618 | 30,207,711 | 22 |
| | | | | | | | 23 |

NOTES (Continued)

| Name of Respondent<br>Idaho Power Company | This Report is:<br>(1) X An Original<br>(2) _ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>2017/Q4 |
|---|---|---|---|

FOOTNOTE DATA

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

| Account | 2017 Beginning Balance | Changes during Year DR to 410.1 | Changes during Year CR to 411.1 | 2017 Ending Balance |
|---|---|---|---|---|
| Emission Allowances | 2,001 | | 2,001 | 0 |
| Renewable Energy Certificates (REC) Sales | 52,633 | 851,116 | 777,058 | 126,691 |
| Royalty Income | 361,616 | | 124,276 | 237,340 |
| Pension Expense | 36,782,759 | 9,191,264 | 15,426,200 | 30,547,823 |
| PCA Expense | 20,893,473 | 7,010,630 | 27,904,103 | 0 |
| Intervenor Funding Orders | 160,438 | | 84,138 | 76,300 |
| Fixed Cost Adjustment | 17,375,825 | 1,782,635 | 11,143,024 | 8,015,436 |
| PS & I Costs | 260,755 | | 156,798 | 103,957 |
| Oregon PCAM | 247,953 | 102,200 | 552,533 | (202,380) |
| 2011 LIDAR Surveys Deferral | 102,284 | | 45,648 | 56,636 |
| Boardman Decommission | 554,697 | 13,302 | 190,587 | 377,412 |
| Valmy Settlement Adjustment | 0 | 16,795,263 | 5,635,510 | 11,159,753 |
| EIM Deferral | 0 | 315,248 | 105,779 | 209,469 |
| Langley Revenue Accrual | 370,974 | 377,438 | 1,192,862 | (444,450) |
| Conservation Expenses | 2,145,392 | 89,240 | 985,826 | 1,248,806 |
| Oregon Excess Power Costs | (64,691) | 64,691 | 0 | 0 |
| Siemens LTP Contract | 37,092 | 32,368 | 23,307 | 46,153 |
| Prepaid Credit Facility | 272,859 | | 128,431 | 144,428 |
| Siemens OR DRB Interest Reserve | 0 | 4,524 | 13,482 | (8,958) |
| Boardman Removal Costs | 0 | 8,652 | 2,903 | 5,749 |
| **TOTAL Line 3** | 79,556,060 | 36,638,571 | 64,494,466 | 51,700,165 |

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

| Account | 2017 Beginning Balance | Adjustments Credits Acct. debited | Adjustments Credits Amount | 2017 Ending Balance |
|---|---|---|---|---|
| Pension-FAS 158 | 103,332,881 | 190 | (31,264,460) | 72,068,421 |
| Postretirement Plan-FAS 158 | (32,449) | 190 | 823,584 | 791,135 |
| **TOTAL Line 8** | 103,300,432 | | (30,440,876) | 72,859,556 |

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

| Account | 2017 Beginning Balance | DR to 410.2 | CR to 411.2 | 2017 Ending Balance |
|---|---|---|---|---|
| EDC-Unrealized Gain/Loss From Rabbit Trust | 4,420 | 2,311 | 2,258 | 4,473 |
| SMSP-Unrealized Gain/Loss From Rabbi Trust | (100,050) | 92,064 | | (7,986) |
| Oregon Non-Op Prop Tax Adj | 372 | 10 | 129 | 253 |
| **TOTAL Line 18** | (95,258) | 94,385 | 2,387 | (3,260) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities (a) | Balance at Begining of Current Quarter/Year (b) | DEBITS Account Credited (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | Market to Market Short Term - (254001) | 7,831,417 | 171 | 7,813,262 | | 18,155 |
| 2 | IPUC Order #28661 | | | | | |
| 3 | | | | | | |
| 4 | Oregon Solar Pilot (254005) | 3,762,081 | Various | 27,937 | 895,347 | 4,629,491 |
| 5 | Order #10-198 | | | | | |
| 6 | | | | | | |
| 7 | Idaho DSM Rider (254201) | 10,730,151 | Various | 51,962,141 | 41,639,594 | 407,604 |
| 8 | IPUC Order #29026 | | | | | |
| 9 | | | | | | |
| 10 | Other Reg Liab-ID BRDMN Decomm (254393) | | | | 947,242 | 947,242 |
| 11 | | | | | | |
| 12 | BPA Credit Residential Idaho (254401) | 1,848,994 | Various | 9,895,622 | 9,011,111 | 964,483 |
| 13 | Advice #15-13 | | | | | |
| 14 | | | | | | |
| 15 | Oregon Green Tags (254415) | 41,692 | 254 | 32,419 | 98,771 | 108,044 |
| 16 | Advice #11-086 | | | | | |
| 17 | | | | | | |
| 18 | Bridger Depreciation (254800) | 1,451,436 | | | 487,403 | 1,938,839 |
| 19 | OPUC Order #12-296 | | | | | |
| 20 | | | | | | |
| 21 | RL-WAQC CRYOVR (254901) | 64,501 | | | 40,101 | 104,602 |
| 22 | IPUC Order #29505 | | | | | |
| 23 | | | | | | |
| 24 | Unfunded Accum Def Income Tax (254966) | 51,326,330 | Various | 21,377,454 | 717,178 | 30,666,054 |
| 25 | | | | | | |
| 26 | RL-DEF INC TAX-ARAM (254967) | | | | 193,991,452 | 193,991,452 |
| 27 | | | | | | |
| 28 | RL-DEF INC TAX-ARAM GROSS-UP (254968) | | | | 68,077,705 | 68,077,705 |
| 29 | | | | | | |
| 30 | RA-PCA Deferral-ID (254425) | | Various | 50,060,290 | 55,396,931 | 5,336,641 |
| 31 | | | | | | |
| 32 | RA-OR BDMN Decomm Order #12-235 | | Various | 206,686 | 354,590 | 147,904 |
| 33 | | | | | | |
| 34 | Minor Items (7) | ( 13,589) | | 1,811,734 | 1,891,313 | 65,990 |
| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 77,043,013 | | 143,187,545 | 373,548,738 | 307,404,206 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | Operating Revenues Year to Date Quarterly/Annual<br>(b) | Operating Revenues Previous year (no Quarterly)<br>(c) |
|---|---|---|---|
| 1 | Sales of Electricity | | |
| 2 | (440) Residential Sales | 552,333,276 | 514,953,833 |
| 3 | (442) Commercial and Industrial Sales | | |
| 4 | Small (or Comm.) (See Instr. 4) | 465,145,591 | 455,158,518 |
| 5 | Large (or Ind.) (See Instr. 4) | 195,124,244 | 182,590,036 |
| 6 | (444) Public Street and Highway Lighting | 4,079,095 | 3,996,825 |
| 7 | (445) Other Sales to Public Authorities | | |
| 8 | (446) Sales to Railroads and Railways | | |
| 9 | (448) Interdepartmental Sales | | |
| 10 | TOTAL Sales to Ultimate Consumers | 1,216,682,206 | 1,156,699,212 |
| 11 | (447) Sales for Resale | 33,381,940 | 25,204,985 |
| 12 | TOTAL Sales of Electricity | 1,250,064,146 | 1,181,904,197 |
| 13 | (Less) (449.1) Provision for Rate Refunds | 10,706,040 | 10,706,040 |
| 14 | TOTAL Revenues Net of Prov. for Refunds | 1,239,358,106 | 1,171,198,157 |
| 15 | Other Operating Revenues | | |
| 16 | (450) Forfeited Discounts | | |
| 17 | (451) Miscellaneous Service Revenues | 4,273,744 | 4,089,617 |
| 18 | (453) Sales of Water and Water Power | | |
| 19 | (454) Rent from Electric Property | 15,236,098 | 14,260,349 |
| 20 | (455) Interdepartmental Rents | | |
| 21 | (456) Other Electric Revenues | 39,921,003 | 34,259,879 |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 42,071,453 | 31,490,797 |
| 23 | (457.1) Regional Control Service Revenues | | |
| 24 | (457.2) Miscellaneous Revenues | | |
| 25 | | | |
| 26 | TOTAL Other Operating Revenues | 101,502,298 | 84,100,642 |
| 27 | TOTAL Electric Operating Revenues | 1,340,860,404 | 1,255,298,799 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## ELECTRIC OPERATING REVENUES (Account 400)

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

| MEGAWATT HOURS SOLD | | AVG.NO. CUSTOMERS PER MONTH | | Line No. |
|---|---|---|---|---|
| Year to Date Quarterly/Annual (d) | Amount Previous year (no Quarterly) (e) | Current Year (no Quarterly) (f) | Previous Year (no Quarterly) (g) | |
| | | | | 1 |
| 5,354,568 | 5,004,352 | 448,800 | 440,362 | 2 |
| | | | | 3 |
| 5,838,862 | 5,916,649 | 87,675 | 86,621 | 4 |
| 3,345,712 | 3,243,344 | 120 | 121 | 5 |
| 31,812 | 31,405 | 2,995 | 2,797 | 6 |
| | | | | 7 |
| | | | | 8 |
| | | | | 9 |
| 14,570,954 | 14,195,750 | 539,590 | 529,901 | 10 |
| 2,135,649 | 1,185,879 | | | 11 |
| 16,706,603 | 15,381,629 | 539,590 | 529,901 | 12 |
| | | | | 13 |
| 16,706,603 | 15,381,629 | 539,590 | 529,901 | 14 |

Line 12, column (b) includes $ -4,243,250 of unbilled revenues.

Line 12, column (d) includes -63,190 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) | $ 4,079,240 |
| Misc. Under $250,000 | 194,504 |
| Total Account 451 | $ 4,273,744 |

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

This amount consists of:

| | |
|---|---|
| Alternate Distribution Service | $ 546,278 |
| DSM Activity | 39,240,688 |
| Misc. Under $250,000 | 134,037 |
| Total Account 456 | $ 39,921,003 |

**Schedule Page: 300 Line No.: 21 Column: c**

This amount consists of:

| | |
|---|---|
| Alternate Distribution Service | $ 321,995 |
| DSM Activity | 33,754,060 |
| Misc. Under $250,000 | 183,824 |
| Total Account 456 | $ 34,259,879 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 5,371,991 | 557,376,181 | 447,534 | 12,004 | 0.1038 |
| 3 | 03 - Residential Master Meter | 4,738 | 469,554 | 23 | 206,000 | 0.0991 |
| 4 | 05 - Residential - TOD | 22,175 | 2,216,437 | 1,243 | 17,840 | 0.1000 |
| 5 | 15 - Dusk to dawn lighting | 2,631 | 651,818 | | | 0.2477 |
| 6 | Unbilled Revenues | -46,967 | -3,748,190 | | | 0.0798 |
| 7 | Other Revenues | | -4,632,524 | | | |
| 8 | Total 440 | 5,354,568 | 552,333,276 | 448,800 | 11,931 | 0.1032 |
| 9 | | | | | | |
| 10 | 442-Commercial & Industrial Sales | | | | | |
| 11 | 07 - General service | 155,816 | 19,620,996 | 30,732 | 5,070 | 0.1259 |
| 12 | 09P - General service | 511,873 | 33,863,636 | 227 | 2,254,947 | 0.0662 |
| 13 | 09S - General service | 3,389,881 | 253,743,241 | 34,963 | 96,956 | 0.0749 |
| 14 | 09T - General service | 6,617 | 471,120 | 4 | 1,654,250 | 0.0712 |
| 15 | 15 - Dusk to Dawn Light | 4,249 | 756,975 | | | 0.1782 |
| 16 | 19P - Uniform rate contracts | 2,311,610 | 135,931,129 | 113 | 20,456,726 | 0.0588 |
| 17 | 19S - Uniform rate contracts | 6,047 | 395,410 | 1 | 6,047,000 | 0.0654 |
| 18 | 19T - Uniform rate contracts | 135,052 | 7,702,020 | 3 | 45,017,333 | 0.0570 |
| 19 | 24S - Irrigation Pumping | 1,771,813 | 146,213,125 | 20,820 | 85,101 | 0.0825 |
| 20 | 40 - General service | 10,436 | 918,425 | 929 | 11,234 | 0.0880 |
| 21 | Special Contracts | 897,443 | 46,840,101 | 3 | 299,147,667 | 0.0522 |
| 22 | Commercial & Industrial Unbill | -16,263 | -501,763 | | | 0.0309 |
| 23 | Other Revenues | | 14,315,420 | | | |
| 24 | Total 442 | 9,184,574 | 660,269,835 | 87,795 | 104,614 | 0.0719 |
| 25 | | | | | | |
| 26 | 444 - Public Street Lighting: | | | | | |
| 27 | 40 - General service | 784 | 69,294 | 461 | 1,701 | 0.0884 |
| 28 | 41 - Street lighting | 28,195 | 3,787,097 | 1,941 | 14,526 | 0.1343 |
| 29 | 42 - Traffic control lighting | 2,793 | 180,128 | 593 | 4,710 | 0.0645 |
| 30 | Unbilled | 40 | 6,703 | | | 0.1676 |
| 31 | Other Revenues | | 35,873 | | | |
| 32 | Total 444 | 31,812 | 4,079,095 | 2,995 | 10,622 | 0.1282 |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| | | | | | | |
| 41 | TOTAL Billed | 14,634,144 | 1,220,925,456 | 539,590 | 27,121 | 0.0834 |
| 42 | Total Unbilled Rev.(See Instr. 6) | -63,190 | -4,243,250 | 0 | 0 | 0.0672 |
| 43 | TOTAL | 14,570,954 | 1,216,682,206 | 539,590 | 27,004 | 0.0835 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## SALES FOR RESALE (Account 447)

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classification (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | 3Phases Renewables, Inc. | SF | WSPP | | | |
| 2 | ADM Investor Services, Inc. | OS | - | | | |
| 3 | Arizona Public Service Co. | SF | WSPP | | | |
| 4 | Avangrid Renewables, LLC | SF | WSPP | | | |
| 5 | Avangrid Renewables, LLC | OS | WSPP | | | |
| 6 | Avista Corp. | OS | WSPP | | | |
| 7 | Avista Corp. | SF | WSPP | | | |
| 8 | Basin Electric Power Cooperative | OS | WSPP | | | |
| 9 | Basin Electric Power Cooperative | SF | WSPP | | | |
| 10 | Black Hills Power Inc. | OS | WSPP | | | |
| 11 | Black Hills Power Inc. | SF | WSPP | | | |
| 12 | Black Hills Power Inc. | OS | WSPP | | | |
| 13 | Bonneville Power Administration | SF | WSPP | | | |
| 14 | Bonneville Power Administration | OS | WSPP | | | |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE: Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 54,925 | | 1,132,719 | | 1,132,719 | 1 |
| | | | 951,740 | 951,740 | 2 |
| 11,783 | | 93,269 | | 93,269 | 3 |
| 7,978 | | 116,711 | | 116,711 | 4 |
| | | | 18,382 | 18,382 | 5 |
| 11,000 | | | 67,020 | 67,020 | 6 |
| 266,625 | | 4,577,653 | | 4,577,653 | 7 |
| 10,367 | | | 34,532 | 34,532 | 8 |
| 17,945 | | 68,516 | | 68,516 | 9 |
| 62,863 | | | 394,460 | 394,460 | 10 |
| 35,817 | | 236,166 | | 236,166 | 11 |
| | | | 59 | 59 | 12 |
| 44,641 | | 886,927 | | 886,927 | 13 |
| 1 | | | 36 | 36 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 2,135,649 | 0 | 29,244,648 | 4,137,292 | 33,381,940 | |
| **2,135,649** | **0** | **29,244,648** | **4,137,292** | **33,381,940** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Brookefield Energy Marketing | SF | WSPP | | | |
| 2 | Calpine Energy Services, L.P. | SF | WSPP | | | |
| 3 | Cargill Power Markets LLC | SF | WSPP | | | |
| 4 | Cargill Power Markets LLC | OS | WSPP | | | |
| 5 | Citigroup Energy Inc. | SF | WSPP | | | |
| 6 | Citigroup Energy Inc. | OS | WSPP | | | |
| 7 | City of Anaheim | SF | WSPP | | | |
| 8 | Clatskanie PUD | SF | WSPP | | | |
| 9 | CP Energy Marketing (US) Inc. | SF | WSPP | | | |
| 10 | EDF Trading North America, LLC | OS | WSPP | | | |
| 11 | EDF Trading North America, LLC | SF | WSPP | | | |
| 12 | Energy Keepers | OS | WSPP | | | |
| 13 | Energy Keepers | SF | WSPP | | | |
| 14 | Energy Keepers | OS | WSPP | | | |
| | | | | | | |
| | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Eugene Electric Board | SF | WSPP | | | |
| 2 | Exelon Generation Company. LLC | SF | WSPP | | | |
| 3 | Macquarie Energy LLC | SF | WSPP | | | |
| 4 | Macquarie Energy LLC | OS | WSPP | | | |
| 5 | Morgan Stanley Capital Group Inc. | OS | ISDA | | | |
| 6 | Morgan Stanley Capital Group Inc. | SF | ISDA | | | |
| 7 | Morgan Stanley Capital Group Inc. | OS | WSPP | | | |
| 8 | Municipal Energy Agency of Nebraska | OS | WSPP | | | |
| 9 | Municipal Energy Agency of Nebraska | SF | WSPP | | | |
| 10 | NV Energy | OS | WSPP | | | |
| 11 | NV Energy | SF | WSPP | | | |
| 12 | NV Energy | OS | WSPP | | | |
| 13 | NorthWestern Energy | OS | WSPP | | | |
| 14 | NorthWestern Energy | SF | WSPP | | | |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 4,786 | | 155,200 | | 155,200 | 1 |
| 764 | | 16,563 | | 16,563 | 2 |
| 602 | | 14,628 | | 14,628 | 3 |
| | | | 109 | 109 | 4 |
| 28,236 | | | 130,713 | 130,713 | 5 |
| 239,584 | | 2,617,265 | | 2,617,265 | 6 |
| | | | 1,338,642 | 1,338,642 | 7 |
| 126 | | | 630 | 630 | 8 |
| 410 | | 4,139 | | 4,139 | 9 |
| 2,172 | | | 22,004 | 22,004 | 10 |
| 145,305 | | 1,158,638 | | 1,158,638 | 11 |
| | | | 40 | 40 | 12 |
| 14,575 | | | 111,154 | 111,154 | 13 |
| 10,908 | | 212,189 | | 212,189 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 2,135,649 | 0 | 29,244,648 | 4,137,292 | 33,381,940 | |
| **2,135,649** | **0** | **29,244,648** | **4,137,292** | **33,381,940** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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)<br>(a) | Statistical Classifi-cation<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) Average Monthly NCP Demand<br>(e) | Actual Demand (MW) Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | NorthWestern Energy | OS | T-7 | | | |
| 2 | PacifiCorp Inc. | OS | WSPP | | | |
| 3 | PacifiCorp Inc. | SF | WSPP | | | |
| 4 | PacifiCorp Inc. | OS | T-7 | | | |
| 5 | Portland General Electric Company | OS | WSPP | | | |
| 6 | Portland General Electric Company | SF | WSPP | | | |
| 7 | Portland General Electric Company | OS | T-7 | | | |
| 8 | Portland General Electric Company | OS | WSPP | | | |
| 9 | Powerex Corp. | OS | WSPP | | | |
| 10 | Powerex Corp. | SF | WSPP | | | |
| 11 | Public Service of Colorado | SF | WSPP | | | |
| 12 | Puget Sound Energy, Inc. | OS | WSPP | | | |
| 13 | Puget Sound Energy, Inc. | SF | WSPP | | | |
| 14 | Puget Sound Energy, Inc. | OS | T-7 | | | |
| | | | | | | |
| | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|
| 7 | | | 204 | 204 | 1 |
| 230 | | | 1,100 | 1,100 | 2 |
| 82,251 | | 1,120,716 | | 1,120,716 | 3 |
| 39 | | | 920 | 920 | 4 |
| 155 | | | 900 | 900 | 5 |
| 21,889 | | 323,031 | | 323,031 | 6 |
| 23 | | | 667 | 667 | 7 |
| | | | 2,912 | 2,912 | 8 |
| 10,580 | | | 28,963 | 28,963 | 9 |
| 41,773 | | 193,026 | | 193,026 | 10 |
| 487 | | 10,569 | | 10,569 | 11 |
| 1,275 | | | 12,750 | 12,750 | 12 |
| 11,468 | | 208,991 | | 208,991 | 13 |
| 109 | | | 3,029 | 3,029 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 2,135,649 | 0 | 29,244,648 | 4,137,292 | 33,381,940 | |
| **2,135,649** | **0** | **29,244,648** | **4,137,292** | **33,381,940** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Rainbow Energy Marketing Corporation | SF | WSPP | | | |
| 2 | Seattle City Light | OS | WSPP | | | |
| 3 | Seattle City Light | SF | WSPP | | | |
| 4 | Shell Energy North America (US), L.P. | OS | WSPP | | | |
| 5 | Shell Energy North America (US), L.P. | SF | WSPP | | | |
| 6 | Shell Energy North America (US), L.P. | OS | WSPP | | | |
| 7 | Sierra Pacific Power Co., dba NV Energy | OS | T-7 | | | |
| 8 | Snohomish County PUD | SF | WSPP | | | |
| 9 | Tacoma Power | OS | WSPP | | | |
| 10 | Tacoma Power | SF | WSPP | | | |
| 11 | Talen Energy Marketing, LLC. | OS | WSPP | | | |
| 12 | Talen Energy Marketing, LLC. | SF | WSPP | | | |
| 13 | Tenaska Power Services Co. | SF | WSPP | | | |
| 14 | Tenaska Power Services Co. | OS | WSPP | | | |
| | | | | | | |
| | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|
| 197,775 | | 1,714,818 | | 1,714,818 | 1 |
| 1,880 | | | 29,465 | 29,465 | 2 |
| 10,063 | | 241,791 | | 241,791 | 3 |
| 48,506 | | | 407,937 | 407,937 | 4 |
| 254,163 | | 4,287,302 | | 4,287,302 | 5 |
| | | | 462,241 | 462,241 | 6 |
| 19 | | | 516 | 516 | 7 |
| 2,413 | | 83,670 | | 83,670 | 8 |
| 50 | | | 500 | 500 | 9 |
| 3,131 | | 67,390 | | 67,390 | 10 |
| 5,200 | | | 29,565 | 29,565 | 11 |
| 7,541 | | 66,113 | | 66,113 | 12 |
| 15,932 | | 69,584 | | 69,584 | 13 |
| | | | 29,569 | 29,569 | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 2,135,649 | 0 | 29,244,648 | 4,137,292 | 33,381,940 | |
| **2,135,649** | **0** | **29,244,648** | **4,137,292** | **33,381,940** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## SALES FOR RESALE (Account 447)

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) Average Monthly NCP Demand<br>(e) | Actual Demand (MW) Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | The Energy Authority, Inc. | SF | WSPP | | | |
| 2 | The Energy Authority, Inc. | OS | WSPP | | | |
| 3 | TransAlta Energy Marketing (U.S.), Inc. | SF | WSPP | | | |
| 4 | TransAlta Energy Marketing (U.S.), Inc. | OS | WSPP | | | |
| 5 | Utah Associated Municipal Power Systems | SF | WSPP | | | |
| 6 | Prior Year Corrections | OS | WSPP | | | |
| 7 | Transmission Penalty Distribution | OS | - | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|
| 265,851 | | 3,932,104 | | 3,932,104 | 1 |
| | | | 5,720 | 5,720 | 2 |
| 8,914 | | 288,947 | | 288,947 | 3 |
| | | | 34,599 | 34,599 | 4 |
| 7,440 | | 278,800 | | 278,800 | 5 |
| 10 | | | 327 | 327 | 6 |
| | | | 56,285 | 56,285 | 7 |
| | | | | | 8 |
| | | | | | 9 |
| | | | | | 10 |
| | | | | | 11 |
| | | | | | 12 |
| | | | | | 13 |
| | | | | | 14 |
| | | | | | |
| 0 | 0 | 0 | 0 | 0 | |
| 2,135,649 | 0 | 29,244,648 | 4,137,292 | 33,381,940 | |
| **2,135,649** | **0** | **29,244,648** | **4,137,292** | **33,381,940** | |

**Schedule Page: 310 Line No.: 2 Column: b**
ADM Investor Futures, Inc Account Document, dated May 5, 2015
**Schedule Page: 310 Line No.: 5 Column: b**
Financial Transmission Losses
**Schedule Page: 310 Line No.: 6 Column: b**
Non-Firm
**Schedule Page: 310 Line No.: 8 Column: b**
Non-Firm
**Schedule Page: 310 Line No.: 10 Column: b**
Non-Firm
**Schedule Page: 310 Line No.: 12 Column: b**
Financial Transmission Losses
**Schedule Page: 310 Line No.: 14 Column: b**
Reserves
**Schedule Page: 310.1 Line No.: 4 Column: b**
Financial Transmission Losses
**Schedule Page: 310.1 Line No.: 6 Column: b**
ISDA Master Agreement with Citigroup Energy Inc. dated March 7, 2011
**Schedule Page: 310.1 Line No.: 10 Column: b**
Non-Firm
**Schedule Page: 310.1 Line No.: 12 Column: b**
Non-Firm
**Schedule Page: 310.1 Line No.: 14 Column: b**
Financial Transmission Losses
**Schedule Page: 310.2 Line No.: 4 Column: b**
Financial Transmission Losses
**Schedule Page: 310.2 Line No.: 5 Column: b**
Non-Firm
**Schedule Page: 310.2 Line No.: 7 Column: b**
Financial Transmission Losses
**Schedule Page: 310.2 Line No.: 8 Column: b**
Non-Firm
**Schedule Page: 310.2 Line No.: 10 Column: b**
Non-Firm
**Schedule Page: 310.2 Line No.: 12 Column: b**
Financial Transmission Losses
**Schedule Page: 310.2 Line No.: 13 Column: b**
Non-Firm
**Schedule Page: 310.3 Line No.: 1 Column: b**
Reserves
**Schedule Page: 310.3 Line No.: 2 Column: b**
Non-Firm
**Schedule Page: 310.3 Line No.: 4 Column: b**
Reserves
**Schedule Page: 310.3 Line No.: 5 Column: b**
Non-Firm
**Schedule Page: 310.3 Line No.: 7 Column: b**
Reserves
**Schedule Page: 310.3 Line No.: 8 Column: b**
Financial Transmission Losses
**Schedule Page: 310.3 Line No.: 9 Column: b**
Non-Firm
**Schedule Page: 310.3 Line No.: 12 Column: b**
Non-Firm

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

Reserves

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

Non-Firm

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

Non-Firm

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

Financial Transmission Losses

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

Reserves

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

Non-Firm

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

Non-Firm

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

Financial Transmission Losses

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

Financial Transmission Losses

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

Financial Transmission Losses

***Schedule Page: 310.5 Line No.: 6 Column: b***

Prior year corrections

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

Transmission penalty distribution credits

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 978,720 | 1,158,861 |
| 5 | (501) Fuel | 107,893,663 | 137,688,753 |
| 6 | (502) Steam Expenses | 8,501,434 | 8,971,192 |
| 7 | (503) Steam from Other Sources | | |
| 8 | (Less) (504) Steam Transferred-Cr. | | |
| 9 | (505) Electric Expenses | 1,396,032 | 1,466,072 |
| 10 | (506) Miscellaneous Steam Power Expenses | 11,694,905 | 9,097,246 |
| 11 | (507) Rents | 328,946 | 206,742 |
| 12 | (509) Allowances | | |
| 13 | TOTAL Operation (Enter Total of Lines 4 thru 12) | 130,793,700 | 158,588,866 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 55,228 | 100,102 |
| 16 | (511) Maintenance of Structures | 440,434 | 528,121 |
| 17 | (512) Maintenance of Boiler Plant | 11,031,366 | 14,263,344 |
| 18 | (513) Maintenance of Electric Plant | 4,331,373 | 5,150,575 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 5,935,275 | 6,435,348 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 21,793,676 | 26,477,490 |
| 21 | TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20) | 152,587,376 | 185,066,356 |
| 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 | 5,699,366 | 5,676,404 |
| 45 | (536) Water for Power | 5,857,068 | 6,025,791 |
| 46 | (537) Hydraulic Expenses | 15,008,403 | 14,667,285 |
| 47 | (538) Electric Expenses | 1,912,278 | 1,696,943 |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 8,270,822 | 5,699,628 |
| 49 | (540) Rents | 241,787 | 235,365 |
| 50 | TOTAL Operation (Enter Total of Lines 44 thru 49) | 36,989,724 | 34,001,416 |
| 51 | C. Hydraulic Power Generation (Continued) | | |
| 52 | Maintenance | | |
| 53 | (541) Mainentance Supervision and Engineering | 94,013 | 116,729 |
| 54 | (542) Maintenance of Structures | 1,139,095 | 1,218,450 |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 821,883 | 658,337 |
| 56 | (544) Maintenance of Electric Plant | 1,877,280 | 2,197,930 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 2,819,560 | 2,345,337 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 6,751,831 | 6,536,783 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58) | 43,741,555 | 40,538,199 |
| | | | |

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<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 60 | D. Other Power Generation | | |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | 687,916 | 738,484 |
| 63 | (547) Fuel | 37,935,165 | 41,802,251 |
| 64 | (548) Generation Expenses | 4,171,670 | 4,155,511 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 986,828 | 807,061 |
| 66 | (550) Rents | | |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 43,781,579 | 47,503,307 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | 226 | |
| 70 | (552) Maintenance of Structures | 335,091 | 400,817 |
| 71 | (553) Maintenance of Generating and Electric Plant | 595,085 | 126,988 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 2,226,109 | 2,764,692 |
| 73 | TOTAL Maintenance (Enter Total of lines 69 thru 72) | 3,156,511 | 3,292,497 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73) | 46,938,090 | 50,795,804 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 244,381,204 | 240,208,728 |
| 77 | (556) System Control and Load Dispatching | 2,885 | 2,678 |
| 78 | (557) Other Expenses | 56,007,259 | -1,206,336 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78) | 300,391,348 | 239,005,070 |
| 80 | TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79) | 543,658,369 | 515,405,429 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 3,150,433 | 2,953,141 |
| 84 | | | |
| 85 | (561.1) Load Dispatch-Reliability | 11,169 | 43,356 |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 1,620,215 | 1,602,644 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 1,526,249 | 1,390,552 |
| 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 | 32,101 | 25,459 |
| 92 | (561.8) Reliability, Planning and Standards Development Services | 1,698,457 | 1,634,564 |
| 93 | (562) Station Expenses | 2,887,872 | 2,637,946 |
| 94 | (563) Overhead Lines Expenses | 1,070,029 | 953,376 |
| 95 | (564) Underground Lines Expenses | | |
| 96 | (565) Transmission of Electricity by Others | 4,568,399 | 5,555,121 |
| 97 | (566) Miscellaneous Transmission Expenses | 25 | 7,471 |
| 98 | (567) Rents | 4,782,018 | 4,139,757 |
| 99 | TOTAL Operation (Enter Total of lines 83 thru 98) | 21,346,967 | 20,943,387 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 154,736 | 169,832 |
| 102 | (569) Maintenance of Structures | | 2,882 |
| 103 | (569.1) Maintenance of Computer Hardware | 31,344 | 27,827 |
| 104 | (569.2) Maintenance of Computer Software | 925,878 | 896,206 |
| 105 | (569.3) Maintenance of Communication Equipment | 8,099 | 15,105 |
| 106 | (569.4) Maintenance of Miscellaneous Regional Transmission Plant | | |
| 107 | (570) Maintenance of Station Equipment | 1,925,172 | 2,220,242 |
| 108 | (571) Maintenance of Overhead Lines | 883,265 | 1,132,781 |
| 109 | (572) Maintenance of Underground Lines | | |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 3,357 | |
| 111 | TOTAL Maintenance (Total of lines 101 thru 110) | 3,931,851 | 4,464,875 |
| 112 | TOTAL Transmission Expenses (Total of lines 99 and 111) | 25,278,818 | 25,408,262 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 4,208,616 | 4,226,094 |
| 135 | (581) Load Dispatching | 4,166,896 | 4,026,028 |
| 136 | (582) Station Expenses | 1,555,734 | 1,544,740 |
| 137 | (583) Overhead Line Expenses | 4,916,620 | 3,606,076 |
| 138 | (584) Underground Line Expenses | 3,615,140 | 3,076,757 |
| 139 | (585) Street Lighting and Signal System Expenses | 118,675 | 82,633 |
| 140 | (586) Meter Expenses | 4,904,919 | 4,717,443 |
| 141 | (587) Customer Installations Expenses | 1,276,382 | 897,759 |
| 142 | (588) Miscellaneous Expenses | 6,886,864 | 7,518,466 |
| 143 | (589) Rents | 381,320 | 305,059 |
| 144 | TOTAL Operation (Enter Total of lines 134 thru 143) | 32,031,166 | 30,001,055 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | -1,643,939 | -1,554,525 |
| 147 | (591) Maintenance of Structures | | |
| 148 | (592) Maintenance of Station Equipment | 3,887,158 | 3,870,899 |
| 149 | (593) Maintenance of Overhead Lines | 13,818,926 | 14,975,930 |
| 150 | (594) Maintenance of Underground Lines | 748,181 | 868,712 |
| 151 | (595) Maintenance of Line Transformers | 23,843 | 28,581 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 554,421 | 588,626 |
| 153 | (597) Maintenance of Meters | 982,875 | 873,691 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 240,442 | 380,105 |
| 155 | TOTAL Maintenance (Total of lines 146 thru 154) | 18,611,907 | 20,032,019 |
| 156 | TOTAL Distribution Expenses (Total of lines 144 and 155) | 50,643,073 | 50,033,074 |
| 157 | 5. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | 945,821 | 617,373 |
| 160 | (902) Meter Reading Expenses | 1,544,764 | 1,649,267 |
| 161 | (903) Customer Records and Collection Expenses | 14,205,692 | 14,631,724 |
| 162 | (904) Uncollectible Accounts | 5,732,560 | 3,946,809 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | -944 | -551 |
| 164 | TOTAL Customer Accounts Expenses (Total of lines 159 thru 163) | 22,427,893 | 20,844,622 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 165 | 6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 166 | Operation | | |
| 167 | (907) Supervision | 821,144 | 796,990 |
| 168 | (908) Customer Assistance Expenses | 44,176,525 | 41,249,994 |
| 169 | (909) Informational and Instructional Expenses | 444,538 | 427,793 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | 641,841 | 449,522 |
| 171 | TOTAL Customer Service and Information Expenses (Total 167 thru 170) | 46,084,048 | 42,924,299 |
| 172 | 7. SALES EXPENSES | | |
| 173 | Operation | | |
| 174 | (911) Supervision | | |
| 175 | (912) Demonstrating and Selling Expenses | | 24 |
| 176 | (913) Advertising Expenses | | |
| 177 | (916) Miscellaneous Sales Expenses | | |
| 178 | TOTAL Sales Expenses (Enter Total of lines 174 thru 177) | | 24 |
| 179 | 8. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 180 | Operation | | |
| 181 | (920) Administrative and General Salaries | 79,079,418 | 81,422,856 |
| 182 | (921) Office Supplies and Expenses | 14,134,583 | 14,772,947 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 27,762,969 | 33,792,414 |
| 184 | (923) Outside Services Employed | 6,769,731 | 8,226,785 |
| 185 | (924) Property Insurance | 3,117,561 | 3,362,154 |
| 186 | (925) Injuries and Damages | 5,647,112 | 5,991,970 |
| 187 | (926) Employee Pensions and Benefits | 46,786,554 | 52,679,051 |
| 188 | (927) Franchise Requirements | | |
| 189 | (928) Regulatory Commission Expenses | 4,260,709 | 3,818,396 |
| 190 | (929) (Less) Duplicate Charges-Cr. | | |
| 191 | (930.1) General Advertising Expenses | 364,410 | 582,063 |
| 192 | (930.2) Miscellaneous General Expenses | 3,556,441 | 3,552,222 |
| 193 | (931) Rents | -350 | |
| 194 | TOTAL Operation (Enter Total of lines 181 thru 193) | 135,953,200 | 140,616,030 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 6,737,813 | 6,271,101 |
| 197 | TOTAL Administrative & General Expenses (Total of lines 194 and 196) | 142,691,013 | 146,887,131 |
| 198 | TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197) | 830,783,214 | 801,502,841 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Cogeneration and Small Power Producers | | | | | |
| 2 | American Falls Solar, LLC | LU | - | N/A | N/A | N/A |
| 3 | American Falls Solar II, LLC | LU | - | N/A | N/A | N/A |
| 4 | AgPower Jerome / Double A Digester | LU | - | N/A | N/A | N/A |
| 5 | Allan Ravenscroft/Malad River | LU | - | N/A | N/A | N/A |
| 6 | Baker City Hydro | LU | - | N/A | N/A | N/A |
| 7 | Bannock County, Idaho | LU | - | N/A | N/A | N/A |
| 8 | Bennett Creek Wind Farm | LU | - | N/A | N/A | N/A |
| 9 | Benson Creek Wind Farm | LU | - | N/A | N/A | N/A |
| 10 | Bettencourt DryCreek Biofactory | LU | - | N/A | N/A | N/A |
| 11 | Big Sky West Dairy Digester | LU | - | N/A | N/A | N/A |
| 12 | Big Wood Canal Company | LU | | | | |
| 13 | Black Canyon #3 | LU | - | N/A | N/A | N/A |
| 14 | Jim Knight | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| | | | | | | | 1 |
| 39,605 | | | | 1,041,522 | | 1,041,522 | 2 |
| 35,608 | | | | 860,271 | | 860,271 | 3 |
| 26,429 | | | | 2,360,837 | | 2,360,837 | 4 |
| 2,865 | | | 155,672 | 118,396 | | 274,068 | 5 |
| 685 | | | | 38,556 | | 38,556 | 6 |
| 11,828 | | | | 663,388 | | 663,388 | 7 |
| 38,682 | | | | 2,482,454 | | 2,482,454 | 8 |
| 25,096 | | | | 1,337,032 | | 1,337,032 | 9 |
| 11,311 | | | | 993,956 | | 993,956 | 10 |
| 9,711 | | | | 645,712 | | 645,712 | 11 |
| | | | | | | | 12 |
| 380 | | | | 26,053 | | 26,053 | 13 |
| 1,082 | | | | 76,075 | | 76,075 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Sagebrush | LU | - | N/A | N/A | N/A |
| 2 | Black Canyon Bliss | LU | - | N/A | N/A | N/A |
| 3 | Blind Canyon Hydro | LU | - | N/A | N/A | N/A |
| 4 | Branchflower/Trout Company | LU | - | N/A | N/A | N/A |
| 5 | Burley Butte Wind Park | LU | - | N/A | N/A | N/A |
| 6 | Bypass Limited | LU | - | N/A | N/A | N/A |
| 7 | Camp Reed Wind Park | LU | - | N/A | N/A | N/A |
| 8 | Cargill Inc./B6 Anaerobic Digester | LU | - | N/A | N/A | N/A |
| 9 | Cassia Wind Farm | LU | - | N/A | N/A | N/A |
| 10 | CCP OR Tenant 1, LLC - Grove | LU | - | N/A | N/A | N/A |
| 11 | CCP OR Tenant 1, LLC - Hyline | LU | - | N/A | N/A | N/A |
| 12 | CCP OR Tenant 1, LLC - Open Range | LU | - | N/A | N/A | N/A |
| 13 | CCP OR Tenant 1, LLC - Railroad | LU | - | N/A | N/A | N/A |
| 14 | CCP OR Tenant 1, LLC - Vale Air | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 944 | | | | 65,140 | | 65,140 | 1 |
| 74 | | | | 2,239 | | 2,239 | 2 |
| 4,312 | | | | 187,921 | | 187,921 | 3 |
| 857 | | | | 60,034 | | 60,034 | 4 |
| 48,177 | | | | 2,757,620 | | 2,757,620 | 5 |
| 25,633 | | | | 1,410,319 | | 1,410,319 | 6 |
| 60,737 | | | | 5,028,949 | | 5,028,949 | 7 |
| 13,245 | | | | 1,143,588 | | 1,143,588 | 8 |
| 22,110 | | | | 888,987 | | 888,987 | 9 |
| 12,166 | | | | 700,762 | | 700,762 | 10 |
| 17,384 | | | | 1,001,589 | | 1,001,589 | 11 |
| 20,768 | | | | 1,193,558 | | 1,193,558 | 12 |
| 9,355 | | | | 539,392 | | 539,392 | 13 |
| 19,827 | | | | 1,141,973 | | 1,141,973 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | CCP OR Tenant 1, LLC - Thunderegg | LU | - | N/A | N/A | N/A |
| 2 | City of Cove, Oregon / Mill Creek | LU | - | N/A | N/A | N/A |
| 3 | City of Hailey | LU | - | N/A | N/A | N/A |
| 4 | City of Pocatello | LU | - | N/A | N/A | N/A |
| 5 | Clear Springs Food Inc. | LU | - | N/A | N/A | N/A |
| 6 | Clifton E. Jenson/Birch Creek | LU | - | N/A | N/A | N/A |
| 7 | Cold Springs Windfarm, LLC | LU | - | N/A | N/A | N/A |
| 8 | Consolidated Hydro Inc. / Enel | | | | | |
| 9 | Barber Dam | LU | - | N/A | N/A | N/A |
| 10 | Dietrich Drop | LU | - | N/A | N/A | N/A |
| 11 | GeoBon #2 | LU | - | N/A | N/A | N/A |
| 12 | Lowline #2 | LU | - | N/A | N/A | N/A |
| 13 | Rock Creek #2 | LU | - | N/A | N/A | N/A |
| 14 | Contractors Power Group Inc./Mile 28 | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 20,310 | | | | 1,166,492 | | 1,166,492 | 1 |
| 2,193 | | | | 144,845 | | 144,845 | 2 |
| 145 | | | | 9,943 | | 9,943 | 3 |
| 1,379 | | | | 102,546 | | 102,546 | 4 |
| 3,477 | | | | 338,418 | | 338,418 | 5 |
| 326 | | | 17,500 | 13,494 | | 30,994 | 6 |
| 46,579 | | | | 3,357,560 | | 3,357,560 | 7 |
| | | | | | | | 8 |
| 14,163 | | | | 715,958 | | 715,958 | 9 |
| 7,145 | | | | 390,891 | | 390,891 | 10 |
| 4,348 | | | | 314,527 | | 314,527 | 11 |
| 9,503 | | | | 514,138 | | 514,138 | 12 |
| 8,899 | | | | 437,516 | | 437,516 | 13 |
| 6,043 | | | | 423,241 | | 423,241 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Crystal Springs Hydro | LU | - | N/A | N/A | N/A |
| 2 | Curry Cattle Company | LU | - | N/A | N/A | N/A |
| 3 | David McCollum/Canyon Springs | LU | - | N/A | N/A | N/A |
| 4 | David R Snedigar | LU | - | N/A | N/A | N/A |
| 5 | Desert Meadow Windfarm | LU | - | N/A | N/A | N/A |
| 6 | Durbin Creek Windfarm | LU | - | N/A | N/A | N/A |
| 7 | Eightmile Hydro Corp | LU | - | N/A | N/A | N/A |
| 8 | Faulkner Brothers Hydro Inc. | LU | - | N/A | N/A | N/A |
| 9 | Fisheries Development | LU | - | N/A | N/A | N/A |
| 10 | Fossil Gulch Wind | LU | - | N/A | N/A | N/A |
| 11 | G2 Energy Hidden Hollow | LU | - | N/A | N/A | N/A |
| 12 | Golden Valley Wind Park | LU | - | N/A | N/A | N/A |
| 13 | Grand View PV Solar Two, LLC | 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 |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 11,964 | | | | 813,166 | | 813,166 | 1 |
| 706 | | | 26,796 | 29,172 | | 55,968 | 2 |
| 445 | | | | 6,802 | | 6,802 | 3 |
| 1,442 | | | | 99,856 | | 99,856 | 4 |
| 53,835 | | | | 3,898,828 | | 3,898,828 | 5 |
| 21,857 | | | | 1,171,921 | | 1,171,921 | 6 |
| 1,583 | | | | 97,421 | | 97,421 | 7 |
| 3,335 | | | | 261,733 | | 261,733 | 8 |
| 839 | | | | 12,028 | | 12,028 | 9 |
| 23,350 | | | | 1,368,539 | | 1,368,539 | 10 |
| 20,602 | | | | 1,372,843 | | 1,372,843 | 11 |
| 28,333 | | | | 1,609,852 | | 1,609,852 | 12 |
| 168,937 | | | | 8,425,392 | | 8,425,392 | 13 |
| 53,163 | | | | 3,842,143 | | 3,842,143 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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 | Hazelton B Power Company | LU | - | N/A | N/A | N/A |
| 2 | Head of U Canal | LU | - | N/A | N/A | N/A |
| 3 | High Mesa Energy | LU | - | N/A | N/A | N/A |
| 4 | H.K. Hydro Mud Creek S & S | LU | - | N/A | N/A | N/A |
| 5 | Horseshoe Bend Hydro | LU | - | N/A | N/A | N/A |
| 6 | Horseshoe Bend Wind/United Materials | LU | - | N/A | N/A | N/A |
| 7 | Hot Springs Wind Farm | LU | - | N/A | N/A | N/A |
| 8 | ID Solar 1, LLC | LU | - | N/A | N/A | N/A |
| 9 | Idaho Winds / Sawtooth Wind Project | LU | - | N/A | N/A | N/A |
| 10 | J R Simplot Co. | IU | - | N/A | N/A | N/A |
| 11 | J.M. Miller/Sahko Hydro | LU | - | N/A | N/A | N/A |
| 12 | James B. Howell / CHI Elk Creek | LU | - | N/A | N/A | N/A |
| 13 | Jett Creek Windfarm | LU | - | N/A | N/A | N/A |
| 14 | John R LeMoyne | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 21,460 | | | | 1,582,526 | | 1,582,526 | 1 |
| 4,370 | | | | 377,577 | | 377,577 | 2 |
| 86,357 | | | | 4,289,476 | | 4,289,476 | 3 |
| 1,678 | | | | 92,509 | | 92,509 | 4 |
| 36,999 | | | | 2,736,637 | | 2,736,637 | 5 |
| 19,315 | | | | 1,161,722 | | 1,161,722 | 6 |
| 35,381 | | | | 2,270,062 | | 2,270,062 | 7 |
| 88,232 | | | | 3,477,970 | | 3,477,970 | 8 |
| 51,360 | | | | 4,208,852 | | 4,208,852 | 9 |
| 68,343 | | | | 3,404,449 | | 3,404,449 | 10 |
| 1,370 | | | | 109,651 | | 109,651 | 11 |
| 4,942 | | | | 327,389 | | 327,389 | 12 |
| 23,256 | | | | 1,234,524 | | 1,234,524 | 13 |
| 619 | | | | 34,922 | | 34,922 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW): Average Monthly NCP Demand<br>(e) | Actual Demand (MW): Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Kasel & Witherspoon | LU | - | N/A | N/A | N/A |
| 2 | Kootenai Electric Cooperative / Fighti | LU | - | N/A | N/A | N/A |
| 3 | Koyle Hydro Inc. | LU | - | N/A | N/A | N/A |
| 4 | Lateral 10 Ventures | LU | - | N/A | N/A | N/A |
| 5 | Lemhi Hydro Power Co./Schaffner | LU | - | N/A | N/A | N/A |
| 6 | Lime Wind | LU | - | N/A | N/A | N/A |
| 7 | Little Mac Power Co./Cedar Draw | LU | - | N/A | N/A | N/A |
| 8 | Little Wood River Irrigation District | LU | - | N/A | N/A | N/A |
| 9 | Magic Reservoir Hydro | LU | - | N/A | N/A | N/A |
| 10 | Mainline Windfarm | LU | - | N/A | N/A | N/A |
| 11 | Marco Rancher's Irrigation Inc. | LU | - | N/A | N/A | N/A |
| 12 | Marysville Hydro Partners/Falls River | LU | - | N/A | N/A | N/A |
| 13 | Milner Dam Wind Park | LU | - | N/A | N/A | N/A |
| 14 | Mountain Home Solar I, LLC | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 2,196 | | | | 196,806 | | 196,806 | 1 |
| 11,490 | | | | 882,547 | | 882,547 | 2 |
| 4,013 | | | | 379,697 | | 379,697 | 3 |
| 8,329 | | | | 553,269 | | 553,269 | 4 |
| 1,268 | | | | 95,977 | | 95,977 | 5 |
| 5,454 | | | | 417,960 | | 417,960 | 6 |
| 5,895 | | | | 379,869 | | 379,869 | 7 |
| 8,181 | | | | 617,184 | | 617,184 | 8 |
| | | | | | | | 9 |
| 50,837 | | | | 3,678,022 | | 3,678,022 | 10 |
| 3,442 | | | | 236,474 | | 236,474 | 11 |
| 64,811 | | | | 4,358,985 | | 4,358,985 | 12 |
| 49,228 | | | | 2,816,092 | | 2,816,092 | 13 |
| 37,060 | | | | 901,313 | | 901,313 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Mud Creek White Hydro, Inc | LU | - | N/A | N/A | N/A |
| 2 | Murphy Flat Poewr, LLC | LU | - | N/A | N/A | N/A |
| 3 | New Energy One / Rock Creek Dairy | LU | - | N/A | N/A | N/A |
| 4 | North Gooding Main, Hydro | LU | - | N/A | N/A | N/A |
| 5 | Orchard Ranch Solar, LLC | LU | - | N/A | N/A | N/A |
| 6 | Oregon Trail Wind Park | LU | - | N/A | N/A | N/A |
| 7 | Owyhee Irrigation District | | | | | |
| 8 | Mitchell Butte | LU | - | N/A | N/A | N/A |
| 9 | Owyhee Dam | LU | - | N/A | N/A | N/A |
| 10 | Tunnel #1 | LU | - | N/A | N/A | N/A |
| 11 | Paynes Ferry Wind Park | LU | - | N/A | N/A | N/A |
| 12 | Pigeon Cove Power | LU | - | N/A | N/A | N/A |
| 13 | Pilgrim Stage Station Wind Park | LU | - | N/A | N/A | N/A |
| 14 | Pristine Springs Inc #1 | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 566 | | | | 38,697 | | 38,697 | 1 |
| 35,928 | | | | 980,219 | | 980,219 | 2 |
| 10,327 | | | | 480,617 | | 480,617 | 3 |
| 4,312 | | | | 373,411 | | 373,411 | 4 |
| 42,105 | | | | 986,519 | | 986,519 | 5 |
| 34,338 | | | | 1,994,747 | | 1,994,747 | 6 |
| | | | | | | | 7 |
| 7,363 | | | | 222,296 | | 222,296 | 8 |
| 28,012 | | | | 690,212 | | 690,212 | 9 |
| 22,861 | | | | 2,617,749 | | 2,617,749 | 10 |
| 56,462 | | | | 4,649,752 | | 4,649,752 | 11 |
| 6,369 | | | 345,676 | 228,981 | | 574,657 | 12 |
| 30,096 | | | | 1,749,627 | | 1,749,627 | 13 |
| 774 | | | | 48,611 | | 48,611 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical 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 | Pristine Springs Inc. #3 | LU | - | N/A | N/A | N/A |
| 2 | Prospector Windfarm | LU | - | N/A | N/A | N/A |
| 3 | Reynolds Irrigation District | LU | - | N/A | N/A | N/A |
| 4 | Richard Kaster | | | | | |
| 5 | Box Canyon | LU | - | N/A | N/A | N/A |
| 6 | Briggs Creek | LU | - | N/A | N/A | N/A |
| 7 | Riverside Hydro/Mora Drop | LU | - | N/A | N/A | N/A |
| 8 | Riverside Investments | | | | | |
| 9 | Arena Drop | LU | - | N/A | N/A | N/A |
| 10 | Fargo Drop | LU | - | N/A | N/A | N/A |
| 11 | Rock Creek #1 Joint Venture | LU | - | N/A | N/A | N/A |
| 12 | Rockland Wind Project | LU | - | N/A | N/A | N/A |
| 13 | Rupert Cogeneration Partners/Magic Val | LU | - | N/A | N/A | N/A |
| 14 | Ryegrass Windfarm | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 938 | | | | 43,989 | | 43,989 | 1 |
| 22,378 | | | | 1,195,916 | | 1,195,916 | 2 |
| 1,144 | | | | 85,450 | | 85,450 | 3 |
| | | | | | | | 4 |
| 1,830 | | | | 123,668 | | 123,668 | 5 |
| 3,466 | | | | 236,323 | | 236,323 | 6 |
| 4,515 | | | | 288,697 | | 288,697 | 7 |
| | | | | | | | 8 |
| 1,674 | | | | 145,767 | | 145,767 | 9 |
| 3,979 | | | | 227,001 | | 227,001 | 10 |
| 12,516 | | | 552,508 | 517,268 | | 1,069,776 | 11 |
| 231,871 | | | | 15,057,294 | | 15,057,294 | 12 |
| | | | | | | | 13 |
| 48,207 | | | | 3,481,719 | | 3,481,719 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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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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 | Salmon Falls Wind Park | LU | - | N/A | N/A | N/A |
| 2 | SE Hazelton A LP | LU | - | N/A | N/A | N/A |
| 3 | Shorock Hydro Inc. | | | | | |
| 4 | Shoshone CSPP | LU | - | N/A | N/A | N/A |
| 5 | Shoshone #2 | LU | - | N/A | N/A | N/A |
| 6 | Simcoe Solar, LLC | LU | - | N/A | N/A | N/A |
| 7 | Snake River Pottery | LU | - | N/A | N/A | N/A |
| 8 | South Forks Joint Venture/Lowline Cana | LU | - | N/A | N/A | N/A |
| 9 | Tamarack Energy Partnership | LU | - | N/A | N/A | N/A |
| 10 | Tasco - Nampa | OS | - | N/A | N/A | N/A |
| 11 | Tasco - Twin Falls | OS | - | N/A | N/A | N/A |
| 12 | Ted S. Sorenson/Tiber Dam | LU | - | N/A | N/A | N/A |
| 13 | Thousand Springs Wind Park | LU | - | N/A | N/A | N/A |
| 14 | Tuana Gulch Wind Park | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 54,485 | | | | 3,169,591 | | 3,169,591 | 1 |
| 21,940 | | | | 1,642,502 | | 1,642,502 | 2 |
| | | | | | | | 3 |
| 1,828 | | | | 102,649 | | 102,649 | 4 |
| 2,917 | | | | 195,742 | | 195,742 | 5 |
| 42,645 | | | | 1,251,636 | | 1,251,636 | 6 |
| 232 | | | | 17,618 | | 17,618 | 7 |
| 28,325 | | | | 2,057,838 | | 2,057,838 | 8 |
| 22,262 | | | 1,460,856 | 1,054,393 | | 2,515,249 | 9 |
| 8 | | | | | | | 10 |
| 4 | | | | | | | 11 |
| 30,033 | | | | 1,772,657 | | 1,772,657 | 12 |
| 30,173 | | | | 1,751,598 | | 1,751,598 | 13 |
| 26,419 | | | | 1,536,068 | | 1,536,068 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW): Average Monthly NCP Demand<br>(e) | Actual Demand (MW): Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Tuana Springs Expansion | LU | - | N/A | N/A | N/A |
| 2 | Twin Falls Energy/Lowline Midway Hydro | LU | - | N/A | N/A | N/A |
| 3 | Two Ponds Windfarm | LU | - | N/A | N/A | N/A |
| 4 | White Water Ranch | LU | - | N/A | N/A | N/A |
| 5 | William Arkoosh/Littlewood | LU | - | N/A | N/A | N/A |
| 6 | Littlewood River Ranch II | LU | - | N/A | N/A | N/A |
| 7 | Willis and Betty Deveny/Shingle Creek | LU | - | N/A | N/A | N/A |
| 8 | Willow Spring Windfarm | LU | - | N/A | N/A | N/A |
| 9 | Wilson Power Company | LU | - | N/A | N/A | N/A |
| 10 | Yahoo Creek Wind Park | LU | - | N/A | N/A | N/A |
| 11 | Scheduling Deviation | OS | - | N/A | N/A | N/A |
| 12 | Other Purchased Power | | | | | |
| 13 | 3 Phases Renewables Inc. | SF | WSPP | N/A | N/A | N/A |
| 14 | ADM Investor Services, Inc. | OS | - | N/A | N/A | N/A |
| | Total | | | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

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

| MegaWatt Hours Purchased | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received | MegaWatt Hours Delivered | Demand Charges ($) | Energy Charges ($) | Other Charges ($) | Total (j+k+l) of Settlement ($) | |
| (g) | (h) | (i) | (j) | (k) | (l) | (m) | |
| 68,295 | | | | 4,341,362 | | 4,341,362 | 1 |
| 8,852 | | | | 540,182 | | 540,182 | 2 |
| 54,107 | | | | 3,911,614 | | 3,911,614 | 3 |
| 768 | | | | 52,162 | | 52,162 | 4 |
| 4,768 | | | | 344,512 | | 344,512 | 5 |
| 5,440 | | | | 294,232 | | 294,232 | 6 |
| 995 | | | | 72,192 | | 72,192 | 7 |
| 25,676 | | | | 1,374,715 | | 1,374,715 | 8 |
| 24,794 | | | | 1,826,900 | | 1,826,900 | 9 |
| 59,598 | | | | 4,926,146 | | 4,926,146 | 10 |
| 3,590 | | | | | | | 11 |
| | | | | | | | 12 |
| 706 | | | | 13,964 | | 13,964 | 13 |
| | | | | 40,149 | | 40,149 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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 | Arizona Public Service Co. | SF | WSPP | N/A | N/A | N/A |
| 2 | AVANGRID RENEWABLES, LLC | 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 | SF | WSPP | N/A | N/A | N/A |
| 9 | Bonneville Power Administration | OS | 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 | Chelan Co PUD | SF | WSPP | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | 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. |
|---|---|---|---|---|---|---|---|
| 28,400 | | | | 879,600 | | 879,600 | 1 |
| 63,661 | | | | 1,346,484 | | 1,346,484 | 2 |
| 28 | | | | | 607 | 607 | 3 |
| 40,040 | | | | 1,113,805 | | 1,113,805 | 4 |
| | | | | | 68,839 | 68,839 | 5 |
| 1,829 | | | | 13,200 | | 13,200 | 6 |
| 192 | | | | | 4,224 | 4,224 | 7 |
| 63,207 | | | | 1,465,753 | | 1,465,753 | 8 |
| | | | | | 304,157 | 304,157 | 9 |
| 400 | | | | 11,440 | | 11,440 | 10 |
| 43,648 | | | | 1,130,317 | | 1,130,317 | 11 |
| 50 | | | | 350 | | 350 | 12 |
| 3 | | | | | 30 | 30 | 13 |
| 4,400 | | | | 121,584 | | 121,584 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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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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)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW): Average Monthly NCP Demand<br>(e) | Actual Demand (MW): Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Citigroup Energy Inc. | SF | WSPP | N/A | N/A | N/A |
| 2 | Citigroup Energy Inc. | OS | ISDA | N/A | N/A | N/A |
| 3 | Clatskanie PUD | SF | WSPP | N/A | N/A | N/A |
| 4 | Douglas County PUD | OS | WSPP | N/A | N/A | N/A |
| 5 | EDF Trading North America, LLC | SF | WSPP | N/A | N/A | N/A |
| 6 | Energy Keepers, Inc | SF | WSPP | N/A | N/A | N/A |
| 7 | Eugene Electric Board | SF | WSPP | N/A | N/A | N/A |
| 8 | Exelon Generation Company, LLC | SF | WSPP | N/A | N/A | N/A |
| 9 | Grant CO Public Utility District #2 -- | OS | WSPP | N/A | N/A | N/A |
| 10 | Gridforce Energy Management, LLC | OS | NWPP | N/A | N/A | N/A |
| 11 | Macquarie Energy LLC | SF | WSPP | N/A | N/A | N/A |
| 12 | Macquarie Energy LLC | OS | ISDA | N/A | N/A | N/A |
| 13 | Morgan Stanley Capital Group Inc. | SF | ISDA | N/A | N/A | N/A |
| 14 | Nevada Power Company, dba NV Energy | SF | WSPP | N/A | N/A | N/A |
| | Total | | | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES: MegaWatt Hours Received (h) | POWER EXCHANGES: MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER: Demand Charges ($) (j) | COST/SETTLEMENT OF POWER: Energy Charges ($) (k) | COST/SETTLEMENT OF POWER: Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 78,400 | | | | 2,649,753 | | 2,649,753 | 1 |
| | | | | | 11,988 | 11,988 | 2 |
| 908 | | | | 3,094 | | 3,094 | 3 |
| 1 | | | | | 14 | 14 | 4 |
| 103,201 | | | | 2,642,159 | | 2,642,159 | 5 |
| 5,469 | | | | 147,192 | | 147,192 | 6 |
| 850 | | | | 21,258 | | 21,258 | 7 |
| 23,817 | | | | 618,536 | | 618,536 | 8 |
| 11 | | | | | 175 | 175 | 9 |
| 1 | | | | | 14 | 14 | 10 |
| 9,000 | | | | 162,450 | | 162,450 | 11 |
| | | | | | -217,764 | -217,764 | 12 |
| 25,846 | | | | 769,992 | | 769,992 | 13 |
| 21,214 | | | | 518,354 | | 518,354 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW)<br>Average Monthly NCP Demand<br>(e) | Actual Demand (MW)<br>Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Nevada Power Company, dba NV Energy | OS | WSPP | N/A | N/A | N/A |
| 2 | NorthWestern Energy | OS | T-7 | N/A | N/A | N/A |
| 3 | NorthWestern Energy | SF | WSPP | N/A | N/A | N/A |
| 4 | PacifiCorp Inc. | OS | T-13 | N/A | N/A | N/A |
| 5 | PacifiCorp Inc. | SF | WSPP | N/A | N/A | N/A |
| 6 | PacifiCorp Inc. | OS | WSPP | N/A | N/A | N/A |
| 7 | Portland General Electric Company | OS | T-14 | N/A | N/A | N/A |
| 8 | Portland General Electric Company | SF | WSPP | N/A | N/A | N/A |
| 9 | Powerex Corp. | SF | WSPP | N/A | N/A | N/A |
| 10 | Public Service Company of Colorado | SF | WSPP | N/A | N/A | N/A |
| 11 | Puget Sound Energy, Inc. | OS | T-9 | N/A | N/A | N/A |
| 12 | Puget Sound Energy, Inc. | SF | WSPP | N/A | N/A | N/A |
| 13 | Rainbow Energy Marketing Corporation | SF | WSPP | N/A | N/A | N/A |
| 14 | Seattle City Light | OS | WSPP | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES MegaWatt Hours Received (h) | 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. |
|---|---|---|---|---|---|---|---|
| | | | | | 2,925 | 2,925 | 1 |
| 21 | | | | | 455 | 455 | 2 |
| 3,521 | | | | 79,578 | | 79,578 | 3 |
| 140 | | | | | 3,264 | 3,264 | 4 |
| 75,292 | | | | 2,149,505 | | 2,149,505 | 5 |
| | | | | | 22,686 | 22,686 | 6 |
| 37 | | | | | 934 | 934 | 7 |
| 31,247 | | | | 747,367 | | 747,367 | 8 |
| 33,839 | | | | 1,063,781 | | 1,063,781 | 9 |
| 54,943 | | | | 1,426,030 | | 1,426,030 | 10 |
| 44 | | | | | 1,055 | 1,055 | 11 |
| 26,145 | | | | 565,789 | | 565,789 | 12 |
| 3,399 | | | | 27,481 | | 27,481 | 13 |
| 18 | | | | | 372 | 372 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

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

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

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

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

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

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

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classifi-cation (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Seattle City Light | SF | WSPP | N/A | N/A | N/A |
| 2 | Shell Energy North America (US), L.P. | SF | WSPP | N/A | N/A | N/A |
| 3 | Sierra Pacific Power Co., dba NV Energ | OS | T-55 | N/A | N/A | N/A |
| 4 | Snohomish County PUD | SF | WSPP | N/A | N/A | N/A |
| 5 | Tacoma Power | OS | WSPP | N/A | N/A | N/A |
| 6 | Tacoma Power | SF | WSPP | N/A | N/A | N/A |
| 7 | Talen Energy Marketing, LLC | SF | WSPP | N/A | N/A | N/A |
| 8 | Talen Energy Marketing, LLC | OS | WSPP | N/A | N/A | N/A |
| 9 | Tenaska Power Services Co. | SF | WSPP | N/A | N/A | N/A |
| 10 | The Energy Authority, Inc. | SF | WSPP | N/A | N/A | N/A |
| 11 | TransAlta Energy Marketing (U.S.) Inc. | SF | WSPP | N/A | N/A | N/A |
| 12 | Portland General Electric | OS | | N/A | N/A | N/A |
| 13 | Prior Year Correction | AD | | N/A | N/A | N/A |
| 14 | Raft River Energy I LLC | LU | - | N/A | N/A | N/A |
| | Total | | | | | |

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES | | COST/SETTLEMENT OF POWER | | | | Line No. |
|---|---|---|---|---|---|---|---|
| | MegaWatt Hours Received (h) | MegaWatt Hours Delivered (i) | Demand Charges ($) (j) | Energy Charges ($) (k) | Other Charges ($) (l) | Total (j+k+l) of Settlement ($) (m) | |
| 39,261 | | | | 824,652 | | 824,652 | 1 |
| 16,217 | | | | 307,250 | | 307,250 | 2 |
| 78 | | | | | 1,898 | 1,898 | 3 |
| 2,058 | | | | 18,085 | | 18,085 | 4 |
| 4 | | | | | 43 | 43 | 5 |
| 5,649 | | | | 119,690 | | 119,690 | 6 |
| 55,537 | | | | 1,430,489 | | 1,430,489 | 7 |
| 9,267 | | | | | 255,081 | 255,081 | 8 |
| 2,175 | | | | 54,193 | | 54,193 | 9 |
| 6,296 | | | | 124,884 | | 124,884 | 10 |
| 53,098 | | | | 1,820,771 | | 1,820,771 | 11 |
| | | | | | 78,742 | 78,742 | 12 |
| 10 | | | | | 330 | 330 | 13 |
| 84,086 | | | | 5,640,131 | | 5,640,131 | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Telocaset Wind Power Partners LLC | LU | APP-A | N/A | N/A | N/A |
| 2 | Neal Hot Springs Unit #1 | LU | - | N/A | N/A | N/A |
| 3 | Oregon Solar Customers | OS | - | N/A | N/A | N/A |
| 4 | Avista Corp. | EX | - | N/A | N/A | N/A |
| 5 | Bonneville Power Administration | EX | - | N/A | N/A | N/A |
| 6 | NorthWestern Energy | EX | - | N/A | N/A | N/A |
| 7 | PacifiCorp Inc. | EX | - | N/A | N/A | N/A |
| 8 | Sierra Pacific Power Co., dba NV Energ | EX | - | N/A | N/A | N/A |
| 9 | Clatskanie PUD | EX | 153 | N/A | N/A | N/A |
| 10 | Clark Canyon Hydro | OS | 0 | N/A | N/A | N/A |
| 11 | Acctg Valuation of Clatskanie PUD | OS | 0 | N/A | N/A | N/A |
| 12 | Demand Response Avoided Energy | OS | - | N/A | N/A | N/A |
| 13 | | | | | | |
| 14 | | | | | | |
| | Total | | | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

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

| MegaWatt Hours Purchased (g) | POWER EXCHANGES: MegaWatt Hours Received (h) | POWER EXCHANGES: MegaWatt Hours Delivered (i) | COST/SETTLEMENT OF POWER: Demand Charges ($) (j) | COST/SETTLEMENT OF POWER: Energy Charges ($) (k) | COST/SETTLEMENT OF POWER: Other Charges ($) (l) | COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m) | Line No. |
|---|---|---|---|---|---|---|---|
| 302,466 | | | | 18,329,296 | | 18,329,296 | 1 |
| 172,906 | | | | 19,295,177 | | 19,295,177 | 2 |
| 737 | | | | | 15,930 | 15,930 | 3 |
| | 815 | | | | | | 4 |
| | 84,499 | | | | | | 5 |
| | | | | | | | 6 |
| | 62,106 | 125,382 | | | | | 7 |
| | | 1,228 | | | | | 8 |
| | 80,921 | 132,575 | | | | | 9 |
| | | | | | -211,500 | -211,500 | 10 |
| | | | | | -428,088 | -428,088 | 11 |
| | | | | | 6,983,314 | 6,983,314 | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| 4,293,616 | 228,341 | 259,185 | 2,559,008 | 234,922,471 | 6,899,725 | 244,381,204 | |

**Schedule Page: 326.4 Line No.: 1 Column: b**
Ida West, a subsidiary of IDACORP (Idaho Power Company's parent company), has partial ownership of this project.

**Schedule Page: 326.5 Line No.: 12 Column: b**
Ida West, a subsidiary of IDACORP (Idaho Power Company's parent company), has partial ownership of this project.

**Schedule Page: 326.8 Line No.: 8 Column: b**
Ida West, a subsidiary of IDACORP (Idaho Power Company's parent company), has partial ownership of this project.

**Schedule Page: 326.8 Line No.: 10 Column: b**
Non-firm purchases

**Schedule Page: 326.8 Line No.: 11 Column: b**
Non-firm purchases

**Schedule Page: 326.9 Line No.: 9 Column: b**
Ida West, a subsidiary of IDACORP (Idaho Power Company's parent company), has partial ownership of this project.

**Schedule Page: 326.9 Line No.: 11 Column: b**
Difference between booked and scheduled energy

**Schedule Page: 326.9 Line No.: 14 Column: b**
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

**Schedule Page: 326.10 Line No.: 3 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.10 Line No.: 5 Column: b**
Financial Transmission Losses

**Schedule Page: 326.10 Line No.: 7 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.10 Line No.: 9 Column: b**
Financial Transmission Losses

**Schedule Page: 326.10 Line No.: 13 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.11 Line No.: 2 Column: b**
ISDA Master Agreement With Citigroup, dated March 7, 2011

**Schedule Page: 326.11 Line No.: 4 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.11 Line No.: 9 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.11 Line No.: 10 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.11 Line No.: 12 Column: b**
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

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

**Schedule Page: 326.12 Line No.: 2 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.12 Line No.: 4 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.12 Line No.: 6 Column: b**
Financial Transmission Losses

**Schedule Page: 326.12 Line No.: 7 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.12 Line No.: 11 Column: b**
Spinning or Operating Reserves

**Schedule Page: 326.12 Line No.: 14 Column: b**
Spinning or Operating Reserves

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

Spinning or Operating Reserves

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

Spinning or Operating Reserves

***Schedule Page: 326.13 Line No.: 8 Column: b***

Unit Contingent Purchases

***Schedule Page: 326.13 Line No.: 12 Column: b***

Operating agreement with Portland General Electric to still provide power if Boardman Power Plant offline - Boardman Assured

***Schedule Page: 326.13 Line No.: 13 Column: b***

Corrections from 2016

***Schedule Page: 326.14 Line No.: 3 Column: b***

Schedule 88 Oregon Solar

***Schedule Page: 326.14 Line No.: 4 Column: b***

Physical transmission losses

***Schedule Page: 326.14 Line No.: 5 Column: b***

Physical transmission losses

***Schedule Page: 326.14 Line No.: 6 Column: b***

Physical transmission losses

***Schedule Page: 326.14 Line No.: 7 Column: b***

Physical transmission losses

***Schedule Page: 326.14 Line No.: 8 Column: b***

Physical transmission losses

***Schedule Page: 326.14 Line No.: 9 Column: b***

Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

***Schedule Page: 326.14 Line No.: 10 Column: b***

CSPP liquidated damages

***Schedule Page: 326.14 Line No.: 11 Column: b***

Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

***Schedule Page: 326.14 Line No.: 12 Column: b***

Incentive program for customers to reduce demand during peak hours

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classification (d) |
|---|---|---|---|---|
| 1 | Bonneville Power Administration - OTEC | Bonneville Power Administration | Oregon Trails Electric Co-op | FNO |
| 2 | Bonneville Power Administration - USBR | Bonneville Power Administration | United States Bureau of Reclamati | FNO |
| 3 | Bonneville Power Administration - PF | Bonneville Power Administration | Priority Firm Customers | FNO |
| 4 | Milner Irrigation District | United States Bureau of Reclamati | Milner Irrigation District | OLF |
| 5 | Morgan Stanley Capital Group Inc. | Seattle City Light | Bonneville Power Administration | OS |
| 6 | PacifiCorp | PacifiCorp West | PacifiCorp West | FNO |
| 7 | United States Bureau of Indian Affairs | Bonneville Power Administration | United States Bureau of Indian Af | OS |
| 8 | Cycle Horseshoe Bend Wind, LLC | PacifiCorp East | Idaho Power Company | OS |
| 9 | Cycle Horseshoe Bend Wind, LLC | PacifiCorp East | Idaho Power Company | OS |
| 10 | Cycle Horseshoe Bend Wind, LLC | PacifiCorp East | Idaho Power Company | OS |
| 11 | Cycle Horseshoe Bend Wind, LLC | PacifiCorp East | Idaho Power Company | OS |
| 12 | United Materials of Great Falls | PacifiCorp East | Idaho Power Company | OS |
| 13 | United Materials of Great Falls | PacifiCorp East | Idaho Power Company | OS |
| 14 | Mountain Home Solar 1 | | | OS |
| 15 | | | | |
| 16 | PacifiCorp Inc. | PacifiCorp East | Bonneville Power Administration | LFP |
| 17 | PacifiCorp Inc. | PacifiCorp East | PacifiCorp West | LFP |
| 18 | PacifiCorp Inc. | PacifiCorp East | PacifiCorp West | LFP |
| 19 | Morgan Stanley Capital Group Inc. | Idaho Power Company | Bonneville Power Administration | LFP |
| 20 | Bonneville Power Administration | PacifiCorp West | PacifiCorp East | LFP |
| 21 | Bonneville Power Administration | PacifiCorp West | PacifiCorp East | LFP |
| 22 | | | | |
| 23 | APS - Pinnacle West Capital Corp. | Bonneville Power Administration | PacifiCorp East | NF |
| 24 | APS - Pinnacle West Capital Corp. | Bonneville Power Administration | PacifiCorp East | NF |
| 25 | Avangrid Renewables, LLC | PacifiCorp East | Bonneville Power Administration | NF |
| 26 | Avangrid Renewables, LLC | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 27 | Avangrid Renewables, LLC | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| 28 | Avangrid Renewables, LLC | Bonneville Power Administration | PacifiCorp East | NF |
| 29 | Avangrid Renewables, LLC | Bonneville Power Administration | Sierra Pacific Power | NF |
| 30 | Avangrid Renewables, LLC | Avista | Sierra Pacific Power | NF |
| 31 | Avangrid Renewables, LLC | Sierra Pacific Power | Bonneville Power Administration | NF |
| 32 | Avangrid Renewables, LLC | PacifiCorp West | PacifiCorp East | NF |
| 33 | Avangrid Renewables, LLC | PacifiCorp West | PacifiCorp East | NF |
| 34 | Avangrid Renewables, LLC | PacifiCorp West | Sierra Pacific Power | NF |
| | **TOTAL** | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 9 | | | | 346,830 | 346,830 | 1 |
| 9 | | | | 301,394 | 301,394 | 2 |
| 9 | | | | 1,287,727 | 1,287,727 | 3 |
| Legacy | Minidoka, Idaho | Various in Idaho | | 9,341 | 9,341 | 4 |
| 4 | | | | 452,702 | 452,702 | 5 |
| 9 | | | | 2,087 | 2,087 | 6 |
| Legacy | LaGrande, Oregon | Various in Idaho | | 13,788 | 13,788 | 7 |
| 5/6 | BRDY | IPCO | | 9 | 9 | 8 |
| 5/6 | BRDY | IPCOEAST | | 775 | 775 | 9 |
| 5/6 | JEFF | IPCO | | 1,307 | 1,307 | 10 |
| 5/6 | JEFF | IPCOEAST | | 8,219 | 8,219 | 11 |
| 5/6 | BRDY | IPCO | | 2,711 | 2,711 | 12 |
| 5/6 | JEFF | IPCO | | 6,294 | 6,294 | 13 |
| 11 | | | | | | 14 |
| | | | | | | 15 |
| 7/8 | BORA | LAGRANDE | | 457,866 | 457,866 | 16 |
| 7/8 | KPRT | HURR | | 373,861 | 373,861 | 17 |
| 7/8 | BORA | HURR | | 495,862 | 495,862 | 18 |
| 7/8 | LYPK | LAGRANDE | | 19,749 | 19,749 | 19 |
| 7/8 | M500 | KPRT | | 109,873 | 109,873 | 20 |
| 7/8 | SMLK | KPRT | | 208,974 | 208,974 | 21 |
| | | | | | | 22 |
| 7/8 | LAGRANDE | BORA | | 235 | 235 | 23 |
| 7/8 | LAGRANDE | BRDY | | 500 | 500 | 24 |
| 7/8 | BORA | LAGRANDE | | 6 | 6 | 25 |
| 7/8 | BPAT.NWMT | BRDY | | 29 | 29 | 26 |
| 7/8 | BPAT.NWMT | M345 | | 59 | 59 | 27 |
| 7/8 | LAGRANDE | BORA | | 6,693 | 6,693 | 28 |
| 7/8 | LAGRANDE | M345 | | 5,242 | 5,242 | 29 |
| 7/8 | LOLO | M345 | | 832 | 832 | 30 |
| 7/8 | M345 | LAGRANDE | | 325 | 325 | 31 |
| 7/8 | SMLK | BORA | | 6,202 | 6,202 | 32 |
| 7/8 | SMLK | BRDY | | 8 | 8 | 33 |
| 7/8 | SMLK | M345 | | 517 | 517 | 34 |
| | | | 0 | **6,832,886** | **6,832,886** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Black Hills Power Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 2 | Black Hills Power Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 3 | Bonneville Power Administration | NorthWestern/PacifiCorp East | PacifiCorp East | SFP |
| 4 | Bonneville Power Administration | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| 5 | Bonneville Power Administration | PacifiCorp East | Bonneville Power Administration | NF |
| 6 | Bonneville Power Administration | PacifiCorp East | Sierra Pacific Power | NF |
| 7 | Bonneville Power Administration | PacifiCorp East | Bonneville Power Administration | NF |
| 8 | Bonneville Power Administration | PacifiCorp East | Bonneville Power Administration | NF |
| 9 | Bonneville Power Administration | Bonneville Power Administration | PacifiCorp East | NF |
| 10 | Bonneville Power Administration | Bonneville Power Administration | PacifiCorp East | NF |
| 11 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | NF |
| 12 | Bonneville Power Administration | Bonneville Power Administration | Sierra Pacific Power | NF |
| 13 | Bonneville Power Administration | Bonneville Power Administration | Bonneville Power Administration | NF |
| 14 | Bonneville Power Administration | Avista | PacifiCorp East | NF |
| 15 | Bonneville Power Administration | Avista | Bonneville Power Administration | NF |
| 16 | Bonneville Power Administration | Avista | Bonneville Power Administration | NF |
| 17 | Bonneville Power Administration | Avista | Sierra Pacific Power | NF |
| 18 | Bonneville Power Administration | Sierra Pacific Power | PacifiCorp East | NF |
| 19 | Bonneville Power Administration | PacifiCorp West | Sierra Pacific Power | NF |
| 20 | Bonneville Power Administration | PacifiCorp West | PacifiCorp East | NF |
| 21 | Bonneville Power Administration | PacifiCorp West | PacifiCorp East | SFP |
| 22 | Bonneville Power Administration | PacifiCorp West | Sierra Pacific Power | NF |
| 23 | Bonneville Power Administration | PacifiCorp West | Sierra Pacific Power | SFP |
| 24 | Cargill-Alliant | Idaho Power Company | PacifiCorp East | NF |
| 25 | Cargill-Alliant | PacifiCorp East | PacifiCorp East | NF |
| 26 | Cargill-Alliant | PacifiCorp East | PacifiCorp East | NF |
| 27 | Energy Keepers, Inc. | Bonneville Power Administration | Sierra Pacific Power | NF |
| 28 | Macquarie Energy, LLC | PacifiCorp East | Bonneville Power Administration | NF |
| 29 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 30 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Bonneville Power Administration | NF |
| 31 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| 32 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Sierra Pacific Power | SFP |
| 33 | Morgan Stanley Capital Group Inc. | PacifiCorp East | NorthWestern/PacifiCorp East | NF |
| 34 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| | **TOTAL** | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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. |
|---|---|---|---|---|---|---|
| 7/8 | LAGRANDE | BORA | | 563 | 563 | 1 |
| 7/8 | LAGRANDE | JBSN | | 20 | 20 | 2 |
| 7/8 | BPAT.NWMT | BORA | | 7,000 | 7,000 | 3 |
| 7/8 | BPAT.NWMT | M345 | | 46 | 46 | 4 |
| 7/8 | BRDY | BPASID | | 57 | 57 | 5 |
| 7/8 | BRDY | M345 | | 1,330 | 1,330 | 6 |
| 7/8 | KPRT | BPASID | | 975 | 975 | 7 |
| 7/8 | KPRT | OTEC | | 4 | 4 | 8 |
| 7/8 | LAGRANDE | BORA | | 1,022 | 1,022 | 9 |
| 7/8 | LAGRANDE | KPRT | | 37 | 37 | 10 |
| 7/8 | LAGRANDE | LAGRANDE | | 1,910 | 1,910 | 11 |
| 7/8 | LAGRANDE | M345 | | 23,723 | 23,723 | 12 |
| 7/8 | LAGRANDE | OTEC | | 7 | 7 | 13 |
| 7/8 | LOLO | BORA | | 193 | 193 | 14 |
| 7/8 | LOLO | BPASID | | 5 | 5 | 15 |
| 7/8 | LOLO | LAGRANDE | | 901 | 901 | 16 |
| 7/8 | LOLO | M345 | | 593 | 593 | 17 |
| 7/8 | M345 | BORA | | 270 | 270 | 18 |
| 7/8 | M500 | M345 | | 203 | 203 | 19 |
| 7/8 | SMLK | BORA | | 72 | 72 | 20 |
| 7/8 | SMLK | BORA | | 111,907 | 111,907 | 21 |
| 7/8 | SMLK | M345 | | 862 | 862 | 22 |
| 7/8 | SMLK | M345 | | 43,594 | 43,594 | 23 |
| 7/8 | IPCOGEN | BORA | | 400 | 400 | 24 |
| 7/8 | JBSN | BORA | | 1,970 | 1,970 | 25 |
| 7/8 | JEFF | BORA | | 2,687 | 2,687 | 26 |
| 7/8 | LAGRANDE | M345 | | 100 | 100 | 27 |
| 7/8 | BORA | LAGRANDE | | 100 | 100 | 28 |
| 7/8 | AVAT.NWMT | BORA | | 2,455 | 2,455 | 29 |
| 7/8 | AVAT.NWMT | LAGRANDE | | 874 | 874 | 30 |
| 7/8 | AVAT.NWMT | M345 | | 6,323 | 6,323 | 31 |
| 7/8 | AVAT.NWMT | M345 | | 64,524 | 64,524 | 32 |
| 7/8 | BORA | BPAT.NWMT | | 128 | 128 | 33 |
| 7/8 | BORA | BRDY | | 10 | 10 | 34 |
| | | | **0** | **6,832,886** | **6,832,886** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. | PacifiCorp East | Bonneville Power Administration | NF |
| 2 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 3 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | PacifiCorp East | SFP |
| 4 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 5 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | PacifiCorp East | SFP |
| 6 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Bonneville Power Administration | NF |
| 7 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| 8 | Morgan Stanley Capital Group Inc. | NorthWestern/PacifiCorp East | Sierra Pacific Power | SFP |
| 9 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| 10 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | SFP |
| 11 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Bonneville Power Administration | NF |
| 12 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Sierra Pacific Power | NF |
| 13 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Sierra Pacific Power | SFP |
| 14 | Morgan Stanley Capital Group Inc. | PacifiCorp West | PacifiCorp East | NF |
| 15 | Morgan Stanley Capital Group Inc. | PacifiCorp West | PacifiCorp East | SFP |
| 16 | Morgan Stanley Capital Group Inc. | PacifiCorp West | Sierra Pacific Power | NF |
| 17 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| 18 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| 19 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Bonneville Power Administration | NF |
| 20 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Sierra Pacific Power | NF |
| 21 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| 22 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | SFP |
| 23 | Morgan Stanley Capital Group Inc. | PacifiCorp East | PacifiCorp East | NF |
| 24 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Bonneville Power Administration | NF |
| 25 | Morgan Stanley Capital Group Inc. | PacifiCorp East | Sierra Pacific Power | NF |
| 26 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 27 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 28 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 29 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | Sierra Pacific Power | NF |
| 30 | Morgan Stanley Capital Group Inc. | Avista | PacifiCorp East | NF |
| 31 | Morgan Stanley Capital Group Inc. | Avista | PacifiCorp East | SFP |
| 32 | Morgan Stanley Capital Group Inc. | Avista | PacifiCorp East | NF |
| 33 | Morgan Stanley Capital Group Inc. | Avista | PacifiCorp East | SFP |
| 34 | Morgan Stanley Capital Group Inc. | Avista | Sierra Pacific Power | NF |
| | **TOTAL** | | | |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 7/8 | BORA | LAGRANDE | | 232 | 232 | 1 |
| 7/8 | BPAT.NWMT | BORA | | 1,447 | 1,447 | 2 |
| 7/8 | BPAT.NWMT | BORA | | 3,629 | 3,629 | 3 |
| 7/8 | BPAT.NWMT | BRDY | | 494 | 494 | 4 |
| 7/8 | BPAT.NWMT | BRDY | | 26,550 | 26,550 | 5 |
| 7/8 | BPAT.NWMT | LAGRANDE | | 4,548 | 4,548 | 6 |
| 7/8 | BPAT.NWMT | M345 | | 12,138 | 12,138 | 7 |
| 7/8 | BPAT.NWMT | M345 | | 129,191 | 129,191 | 8 |
| 7/8 | BRDY | BORA | | 2,561 | 2,561 | 9 |
| 7/8 | BRDY | BORA | | 5,403 | 5,403 | 10 |
| 7/8 | BRDY | LAGRANDE | | 7,258 | 7,258 | 11 |
| 7/8 | BRDY | M345 | | 24,560 | 24,560 | 12 |
| 7/8 | BRDY | M345 | | 41,937 | 41,937 | 13 |
| 7/8 | H500 | BORA | | 19,090 | 19,090 | 14 |
| 7/8 | H500 | BORA | | 1,027 | 1,027 | 15 |
| 7/8 | H500 | M345 | | 204 | 204 | 16 |
| 7/8 | JBSN | BORA | | 1,895 | 1,895 | 17 |
| 7/8 | JBSN | BRDY | | 2 | 2 | 18 |
| 7/8 | JBSN | LAGRANDE | | 345 | 345 | 19 |
| 7/8 | JBSN | M345 | | 110 | 110 | 20 |
| 7/8 | JEFF | BORA | | 57,428 | 57,428 | 21 |
| 7/8 | JEFF | BORA | | 158 | 158 | 22 |
| 7/8 | JEFF | BRDY | | 830 | 830 | 23 |
| 7/8 | JEFF | LAGRANDE | | 2,431 | 2,431 | 24 |
| 7/8 | JEFF | M345 | | 83,364 | 83,364 | 25 |
| 7/8 | LAGRANDE | BORA | | 41,432 | 41,432 | 26 |
| 7/8 | LAGRANDE | BRDY | | 10,230 | 10,230 | 27 |
| 7/8 | LAGRANDE | JBSN | | 50 | 50 | 28 |
| 7/8 | LAGRANDE | M345 | | 59,338 | 59,338 | 29 |
| 7/8 | LOLO | BORA | | 91,418 | 91,418 | 30 |
| 7/8 | LOLO | BORA | | 14,026 | 14,026 | 31 |
| 7/8 | LOLO | BRDY | | 3,619 | 3,619 | 32 |
| 7/8 | LOLO | BRDY | | 1,718 | 1,718 | 33 |
| 7/8 | LOLO | M345 | | 171,686 | 171,686 | 34 |
| | | | 0 | **6,832,886** | **6,832,886** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. | Avista | Sierra Pacific Power | SFP |
| 2 | Morgan Stanley Capital Group Inc. | Idaho Power Company | NorthWestern/PacifiCorp East | NF |
| 3 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | NF |
| 4 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | SFP |
| 5 | Morgan Stanley Capital Group Inc. | Idaho Power Company | NorthWestern/PacifiCorp East | NF |
| 6 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | NF |
| 7 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | SFP |
| 8 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | NF |
| 9 | Morgan Stanley Capital Group Inc. | Idaho Power Company | Avista | NF |
| 10 | Morgan Stanley Capital Group Inc. | Idaho Power Company | Sierra Pacific Power | NF |
| 11 | Morgan Stanley Capital Group Inc. | Sierra Pacific Power | PacifiCorp East | NF |
| 12 | Morgan Stanley Capital Group Inc. | Sierra Pacific Power | NorthWestern/PacifiCorp East | NF |
| 13 | Morgan Stanley Capital Group Inc. | Sierra Pacific Power | PacifiCorp East | NF |
| 14 | Morgan Stanley Capital Group Inc. | Sierra Pacific Power | Bonneville Power Administration | NF |
| 15 | Morgan Stanley Capital Group Inc. | PacifiCorp West | PacifiCorp East | NF |
| 16 | Morgan Stanley Capital Group Inc. | PacifiCorp West | Sierra Pacific Power | NF |
| 17 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | NF |
| 18 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | SFP |
| 19 | Morgan Stanley Capital Group Inc. | Idaho Power Company | PacifiCorp East | NF |
| 20 | Morgan Stanley Capital Group Inc. | Idaho Power Company | Sierra Pacific Power | NF |
| 21 | Nevada Power Co. | PacifiCorp East | Sierra Pacific Power | NF |
| 22 | Northwestern Energy | PacifiCorp East | Bonneville Power Administration | NF |
| 23 | PacifiCorp Inc. | PacifiCorp East | Avista | NF |
| 24 | PacifiCorp Inc. | PacifiCorp East | NorthWestern/PacifiCorp East | NF |
| 25 | PacifiCorp Inc. | PacifiCorp East | PacifiCorp East | NF |
| 26 | PacifiCorp Inc. | PacifiCorp East | PacifiCorp East | SFP |
| 27 | PacifiCorp Inc. | PacifiCorp East | Bonneville Power Administration | NF |
| 28 | PacifiCorp Inc. | PacifiCorp West | PacifiCorp East | NF |
| 29 | PacifiCorp Inc. | PacifiCorp West | PacifiCorp East | NF |
| 30 | PacifiCorp Inc. | PacifiCorp West | Bonneville Power Administration | NF |
| 31 | PacifiCorp Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 32 | PacifiCorp Inc. | Bonneville Power Administration | PacifiCorp East | NF |
| 33 | PacifiCorp Inc. | Avista | PacifiCorp East | NF |
| 34 | PacifiCorp Inc. | Avista | PacifiCorp East | NF |
| | **TOTAL** | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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. |
|---|---|---|---|---|---|---|
| 7/8 | LOLO | M345 | | 116,499 | 116,499 | 1 |
| 7/8 | LYPK | AVAT.NWMT | | 378 | 378 | 2 |
| 7/8 | LYPK | BORA | | 24,751 | 24,751 | 3 |
| 7/8 | LYPK | BORA | | 32,988 | 32,988 | 4 |
| 7/8 | LYPK | BPAT.NWMT | | 3,297 | 3,297 | 5 |
| 7/8 | LYPK | BRDY | | 8,383 | 8,383 | 6 |
| 7/8 | LYPK | BRDY | | 4,654 | 4,654 | 7 |
| 7/8 | LYPK | JBSN | | 31 | 31 | 8 |
| 7/8 | LYPK | LOLO | | 538 | 538 | 9 |
| 7/8 | LYPK | M345 | | 361,352 | 361,352 | 10 |
| 7/8 | M345 | BORA | | 1,062 | 1,062 | 11 |
| 7/8 | M345 | BPAT.NWMT | | 1,041 | 1,041 | 12 |
| 7/8 | M345 | BRDY | | 1,348 | 1,348 | 13 |
| 7/8 | M345 | LAGRANDE | | 469 | 469 | 14 |
| 7/8 | SMLK | BORA | | 58,628 | 58,628 | 15 |
| 7/8 | SMLK | M345 | | 716 | 716 | 16 |
| 7/8 | WALLAWALLA | BORA | | 14,383 | 14,383 | 17 |
| 7/8 | WALLAWALLA | BORA | | 5,192 | 5,192 | 18 |
| 7/8 | WALLAWALLA | BRDY | | 100 | 100 | 19 |
| 7/8 | WALLAWALLA | M345 | | 123 | 123 | 20 |
| 7/8 | BRDY | M345 | | 144 | 144 | 21 |
| 7/8 | BRDY | LAGRANDE | | 150 | 150 | 22 |
| 7/8 | BORA | LOLO | | 61 | 61 | 23 |
| 7/8 | BRDY | BPAT.NWMT | | 640 | 640 | 24 |
| 7/8 | BRDY | BRDY | | 196 | 196 | 25 |
| 7/8 | BRDY | BRDY | | 1,773 | 1,773 | 26 |
| 7/8 | BRDY | LAGRANDE | | 2,087 | 2,087 | 27 |
| 7/8 | HURR | BORA | | 3,107 | 3,107 | 28 |
| 7/8 | HURR | BRDY | | 890 | 890 | 29 |
| 7/8 | HURR | LAGRANDE | | 2,954 | 2,954 | 30 |
| 7/8 | LAGRANDE | BORA | | 34,476 | 34,476 | 31 |
| 7/8 | LAGRANDE | BRDY | | 13,504 | 13,504 | 32 |
| 7/8 | LOLO | BORA | | 2,190 | 2,190 | 33 |
| 7/8 | LOLO | BRDY | | 1,976 | 1,976 | 34 |
| | | | 0 | **6,832,886** | **6,832,886** | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

| Line No. | Payment By (Company of Public Authority) (Footnote Affiliation) (a) | Energy Received From (Company of Public Authority) (Footnote Affiliation) (b) | Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c) | Statistical Classifi-cation (d) |
|---|---|---|---|---|
| 1 | PacifiCorp Inc. | Avista | PacifiCorp West | NF |
| 2 | PacifiCorp Inc. | Avista | Bonneville Power Administration | NF |
| 3 | PacifiCorp Inc. | PacifiCorp West | PacifiCorp East | NF |
| 4 | PacifiCorp Inc. | PacifiCorp West | PacifiCorp East | SFP |
| 5 | PacifiCorp Inc. | PacifiCorp West | PacifiCorp East | NF |
| 6 | Portland General Electric | PacifiCorp East | Bonneville Power Administration | NF |
| 7 | Powerex Corporation | PacifiCorp East | Bonneville Power Administration | NF |
| 8 | Powerex Corporation | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 9 | Powerex Corporation | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| 10 | Powerex Corporation | PacifiCorp East | PacifiCorp East | NF |
| 11 | Powerex Corporation | PacifiCorp East | Sierra Pacific Power | NF |
| 12 | Powerex Corporation | PacifiCorp East | Bonneville Power Administration | NF |
| 13 | Powerex Corporation | PacifiCorp West | PacifiCorp East | NF |
| 14 | Powerex Corporation | PacifiCorp West | PacifiCorp East | NF |
| 15 | Powerex Corporation | PacifiCorp East | PacifiCorp East | NF |
| 16 | Powerex Corporation | PacifiCorp East | Bonneville Power Administration | NF |
| 17 | Powerex Corporation | PacifiCorp East | PacifiCorp East | NF |
| 18 | Powerex Corporation | PacifiCorp East | PacifiCorp East | NF |
| 19 | Powerex Corporation | PacifiCorp East | Bonneville Power Administration | NF |
| 20 | Powerex Corporation | PacifiCorp East | Sierra Pacific Power | NF |
| 21 | Powerex Corporation | Bonneville Power Administration | PacifiCorp East | NF |
| 22 | Powerex Corporation | Bonneville Power Administration | PacifiCorp East | NF |
| 23 | Powerex Corporation | Bonneville Power Administration | Sierra Pacific Power | NF |
| 24 | Powerex Corporation | Avista | PacifiCorp East | NF |
| 25 | Powerex Corporation | Avista | PacifiCorp East | NF |
| 26 | Powerex Corporation | Sierra Pacific Power | PacifiCorp East | NF |
| 27 | Powerex Corporation | PacifiCorp West | PacifiCorp East | NF |
| 28 | Powerex Corporation | PacifiCorp West | PacifiCorp East | NF |
| 29 | Powerex Corporation | PacifiCorp West | Sierra Pacific Power | NF |
| 30 | Powerex Corporation | Idaho Power Company | PacifiCorp East | NF |
| 31 | Shell Energy North America (US), L.P. | PacifiCorp East | Sierra Pacific Power | NF |
| 32 | Shell Energy North America (US), L.P. | NorthWestern/PacifiCorp East | PacifiCorp East | NF |
| 33 | Shell Energy North America (US), L.P. | NorthWestern/PacifiCorp East | Bonneville Power Administration | NF |
| 34 | Shell Energy North America (US), L.P. | NorthWestern/PacifiCorp East | Sierra Pacific Power | NF |
| | **TOTAL** | | | |

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

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

| FERC Rate Schedule of Tariff Number (e) | Point of Receipt (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY | | Line No. |
|---|---|---|---|---|---|---|
| | | | | MegaWatt Hours Received (i) | MegaWatt Hours Delivered (j) | |
| 7/8 | LOLO | HURR | | 157 | 157 | 1 |
| 7/8 | LOLO | LAGRANDE | | 947 | 947 | 2 |
| 7/8 | SMLK | BORA | | 269,277 | 269,277 | 3 |
| 7/8 | SMLK | BORA | | 1,220 | 1,220 | 4 |
| 7/8 | SMLK | BRDY | | 17,204 | 17,204 | 5 |
| 7/8 | JEFF | LAGRANDE | | 788 | 788 | 6 |
| 7/8 | BORA | LAGRANDE | | 12 | 12 | 7 |
| 7/8 | BPAT.NWMT | BRDY | | 7 | 7 | 8 |
| 7/8 | BPAT.NWMT | M345 | | 20 | 20 | 9 |
| 7/8 | BRDY | BORA | | 125 | 125 | 10 |
| 7/8 | BRDY | M345 | | 624 | 624 | 11 |
| 7/8 | GSHN | LAGRANDE | | 100 | 100 | 12 |
| 7/8 | HURR | BORA | | 15 | 15 | 13 |
| 7/8 | HURR | BRDY | | 12 | 12 | 14 |
| 7/8 | JBSN | BORA | | 114 | 114 | 15 |
| 7/8 | JBSN | LAGRANDE | | 44 | 44 | 16 |
| 7/8 | JEFF | BORA | | 587 | 587 | 17 |
| 7/8 | JEFF | BRDY | | 411 | 411 | 18 |
| 7/8 | JEFF | LAGRANDE | | 31 | 31 | 19 |
| 7/8 | JEFF | M345 | | 233 | 233 | 20 |
| 7/8 | LAGRANDE | BORA | | 6,875 | 6,875 | 21 |
| 7/8 | LAGRANDE | BRDY | | 3,710 | 3,710 | 22 |
| 7/8 | LAGRANDE | M345 | | 804 | 804 | 23 |
| 7/8 | LOLO | BORA | | 706 | 706 | 24 |
| 7/8 | LOLO | BRDY | | 481 | 481 | 25 |
| 7/8 | M345 | BORA | | 200 | 200 | 26 |
| 7/8 | SMLK | BORA | | 9,017 | 9,017 | 27 |
| 7/8 | SMLK | BRDY | | 1,761 | 1,761 | 28 |
| 7/8 | SMLK | M345 | | 1,019 | 1,019 | 29 |
| 7/8 | WALLAWALLA | BORA | | 309 | 309 | 30 |
| 7/8 | BORA | M345 | | 1,564 | 1,564 | 31 |
| 7/8 | BPAT.NWMT | BRDY | | 383 | 383 | 32 |
| 7/8 | BPAT.NWMT | LAGRANDE | | 95 | 95 | 33 |
| 7/8 | BPAT.NWMT | M345 | | 1,786 | 1,786 | 34 |
| | | | 0 | **6,832,886** | **6,832,886** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|---|
| 7/8 | BRDY | BORA | | 848 | 848 | 1 |
| 7/8 | BRDY | BPAT.NWMT | | 338 | 338 | 2 |
| 7/8 | BRDY | LAGRANDE | | 499 | 499 | 3 |
| 7/8 | BRDY | M345 | | 6,271 | 6,271 | 4 |
| 7/8 | BRDY | M345 | | 2,016 | 2,016 | 5 |
| 7/8 | HCPR | LAGRANDE | | 96 | 96 | 6 |
| 7/8 | IPCOGEN | BPAT.NWMT | | 104 | 104 | 7 |
| 7/8 | IPCOGEN | LAGRANDE | | 300 | 300 | 8 |
| 7/8 | JBSN | AVAT.NWMT | | 140 | 140 | 9 |
| 7/8 | JBSN | BORA | | 104 | 104 | 10 |
| 7/8 | JBSN | BPAT.NWMT | | 30 | 30 | 11 |
| 7/8 | JBSN | LAGRANDE | | 2,422 | 2,422 | 12 |
| 7/8 | JBSN | M345 | | 618 | 618 | 13 |
| 7/8 | JEFF | BORA | | 128 | 128 | 14 |
| 7/8 | JEFF | BRDY | | 330 | 330 | 15 |
| 7/8 | JEFF | M345 | | 135 | 135 | 16 |
| 7/8 | LAGRANDE | BORA | | 4,361 | 4,361 | 17 |
| 7/8 | LAGRANDE | BRDY | | 16,254 | 16,254 | 18 |
| 7/8 | LAGRANDE | M345 | | 78,079 | 78,079 | 19 |
| 7/8 | LOLO | BORA | | 241 | 241 | 20 |
| 7/8 | LOLO | BRDY | | 76 | 76 | 21 |
| 7/8 | LOLO | M345 | | 155,586 | 155,586 | 22 |
| 7/8 | LOLO | M345 | | 53,906 | 53,906 | 23 |
| 7/8 | M345 | LAGRANDE | | 614 | 614 | 24 |
| 7/8 | OBBLPR | BORA | | 12 | 12 | 25 |
| 7/8 | OBBLPR | LAGRANDE | | 100 | 100 | 26 |
| 7/8 | OBBLPR | M345 | | 116 | 116 | 27 |
| 7/8 | SMLK | BORA | | 1,248 | 1,248 | 28 |
| 7/8 | SMLK | BRDY | | 6,654 | 6,654 | 29 |
| 7/8 | SMLK | M345 | | 6,799 | 6,799 | 30 |
| 7/8 | SMLK | M345 | | 2,398 | 2,398 | 31 |
| 7/8 | WALLAWALLA | BORA | | 120,005 | 120,005 | 32 |
| 7/8 | WALLAWALLA | BORA | | 7,948 | 7,948 | 33 |
| 7/8 | WALLAWALLA | BRDY | | 6,887 | 6,887 | 34 |
| | | | **0** | **6,832,886** | **6,832,886** | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

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

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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. |
|---|---|---|---|---|---|---|
| 7/8 | WALLAWALLA | M345 | | 16,214 | 16,214 | 1 |
| 7/8 | WALLAWALLA | M345 | | 410 | 410 | 2 |
| 7/8 | BRDY | M345 | | 45,457 | 45,457 | 3 |
| 7/8 | BRDY | LAGRANDE | | 153 | 153 | 4 |
| 7/8 | LAGRANDE | BRDY | | 1,117 | 1,117 | 5 |
| 7/8 | LAGRANDE | M345 | | 1,707 | 1,707 | 6 |
| 7/8 | M345 | LAGRANDE | | 126 | 126 | 7 |
| 7/8 | SMLK | BORA | | 3,432 | 3,432 | 8 |
| 7/8 | SMLK | BRDY | | 440 | 440 | 9 |
| 7/8 | BORA | LAGRANDE | | 412 | 412 | 10 |
| 7/8 | BPAT.NWMT | M345 | | 1,140 | 1,140 | 11 |
| 7/8 | LAGRANDE | BORA | | 17,292 | 17,292 | 12 |
| 7/8 | LAGRANDE | M345 | | 5,530 | 5,530 | 13 |
| 7/8 | LOLO | BORA | | 1,476 | 1,476 | 14 |
| 7/8 | M345 | LAGRANDE | | 105 | 105 | 15 |
| 7/8 | SMLK | BORA | | 23,816 | 23,816 | 16 |
| 7/8 | BORA | M345 | | 234 | 234 | 17 |
| 7/8 | BORA | M345 | | 2,212 | 2,212 | 18 |
| | | | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| | | | | | | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | 0 | **6,832,886** | **6,832,886** | |

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. |
|---|---|---|---|---|
| 1,888,449 | 215,642 | | 2,104,091 | 1 |
| 1,553,654 | 139,011 | | 1,692,665 | 2 |
| 6,883,736 | 886,694 | | 7,770,430 | 3 |
| | 15,132 | | 15,132 | 4 |
| | 197,499 | | 197,499 | 5 |
| 12,208 | 926 | | 13,134 | 6 |
| | 54,759 | | 54,759 | 7 |
| | 6 | | 6 | 8 |
| | 530 | | 530 | 9 |
| | 894 | | 894 | 10 |
| | 5,622 | | 5,622 | 11 |
| | 2,654 | | 2,654 | 12 |
| | 6,162 | | 6,162 | 13 |
| | 82 | | 82 | 14 |
| | | | | 15 |
| | 4,040,454 | | 4,040,454 | 16 |
| | 3,455,285 | | 3,455,285 | 17 |
| | 6,715,513 | | 6,715,513 | 18 |
| | 2,814,385 | | 2,814,385 | 19 |
| | 2,786,520 | | 2,786,520 | 20 |
| | 2,786,520 | | 2,786,520 | 21 |
| | | | | 22 |
| | 2,318 | | 2,318 | 23 |
| | 4,932 | | 4,932 | 24 |
| | 38 | | 38 | 25 |
| | 185 | | 185 | 26 |
| | 377 | | 377 | 27 |
| | 42,747 | | 42,747 | 28 |
| | 33,480 | | 33,480 | 29 |
| | 5,314 | | 5,314 | 30 |
| | 2,076 | | 2,076 | 31 |
| | 39,611 | | 39,611 | 32 |
| | 51 | | 51 | 33 |
| | 3,302 | | 3,302 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 1,638 | | 1,638 | 1 |
| | 58 | | 58 | 2 |
| | 6,574 | | 6,574 | 3 |
| | 43 | | 43 | 4 |
| | 54 | | 54 | 5 |
| | 1,249 | | 1,249 | 6 |
| | 916 | | 916 | 7 |
| | 4 | | 4 | 8 |
| | 960 | | 960 | 9 |
| | 35 | | 35 | 10 |
| | 1,794 | | 1,794 | 11 |
| | 22,281 | | 22,281 | 12 |
| | 7 | | 7 | 13 |
| | 181 | | 181 | 14 |
| | 5 | | 5 | 15 |
| | 846 | | 846 | 16 |
| | 557 | | 557 | 17 |
| | 254 | | 254 | 18 |
| | 191 | | 191 | 19 |
| | 68 | | 68 | 20 |
| | 105,103 | | 105,103 | 21 |
| | 810 | | 810 | 22 |
| | 40,943 | | 40,943 | 23 |
| | 1,706 | | 1,706 | 24 |
| | 8,402 | | 8,402 | 25 |
| | 11,460 | | 11,460 | 26 |
| | 291 | | 291 | 27 |
| | 917 | | 917 | 28 |
| | 5,667 | | 5,667 | 29 |
| | 2,018 | | 2,018 | 30 |
| | 14,596 | | 14,596 | 31 |
| | 148,944 | | 148,944 | 32 |
| | 295 | | 295 | 33 |
| | 23 | | 23 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 536 | | 536 | 1 |
| | 3,340 | | 3,340 | 2 |
| | 8,377 | | 8,377 | 3 |
| | 1,140 | | 1,140 | 4 |
| | 61,287 | | 61,287 | 5 |
| | 10,498 | | 10,498 | 6 |
| | 28,019 | | 28,019 | 7 |
| | 298,219 | | 298,219 | 8 |
| | 5,912 | | 5,912 | 9 |
| | 12,472 | | 12,472 | 10 |
| | 16,754 | | 16,754 | 11 |
| | 56,693 | | 56,693 | 12 |
| | 96,806 | | 96,806 | 13 |
| | 44,067 | | 44,067 | 14 |
| | 2,371 | | 2,371 | 15 |
| | 471 | | 471 | 16 |
| | 4,374 | | 4,374 | 17 |
| | 5 | | 5 | 18 |
| | 796 | | 796 | 19 |
| | 254 | | 254 | 20 |
| | 132,564 | | 132,564 | 21 |
| | 365 | | 365 | 22 |
| | 1,916 | | 1,916 | 23 |
| | 5,612 | | 5,612 | 24 |
| | 192,434 | | 192,434 | 25 |
| | 95,640 | | 95,640 | 26 |
| | 23,614 | | 23,614 | 27 |
| | 115 | | 115 | 28 |
| | 136,973 | | 136,973 | 29 |
| | 211,025 | | 211,025 | 30 |
| | 32,377 | | 32,377 | 31 |
| | 8,354 | | 8,354 | 32 |
| | 3,966 | | 3,966 | 33 |
| | 396,312 | | 396,312 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 268,921 | | 268,921 | 1 |
| | 873 | | 873 | 2 |
| | 57,134 | | 57,134 | 3 |
| | 76,148 | | 76,148 | 4 |
| | 7,611 | | 7,611 | 5 |
| | 19,351 | | 19,351 | 6 |
| | 10,743 | | 10,743 | 7 |
| | 72 | | 72 | 8 |
| | 1,242 | | 1,242 | 9 |
| | 834,129 | | 834,129 | 10 |
| | 2,451 | | 2,451 | 11 |
| | 2,403 | | 2,403 | 12 |
| | 3,112 | | 3,112 | 13 |
| | 1,083 | | 1,083 | 14 |
| | 135,334 | | 135,334 | 15 |
| | 1,653 | | 1,653 | 16 |
| | 33,201 | | 33,201 | 17 |
| | 11,985 | | 11,985 | 18 |
| | 231 | | 231 | 19 |
| | 284 | | 284 | 20 |
| | 419 | | 419 | 21 |
| | 782 | | 782 | 22 |
| | 108 | | 108 | 23 |
| | 1,129 | | 1,129 | 24 |
| | 346 | | 346 | 25 |
| | 3,128 | | 3,128 | 26 |
| | 3,682 | | 3,682 | 27 |
| | 5,482 | | 5,482 | 28 |
| | 1,570 | | 1,570 | 29 |
| | 5,212 | | 5,212 | 30 |
| | 60,833 | | 60,833 | 31 |
| | 23,828 | | 23,828 | 32 |
| | 3,864 | | 3,864 | 33 |
| | 3,487 | | 3,487 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 277 | | 277 | 1 |
| | 1,671 | | 1,671 | 2 |
| | 475,137 | | 475,137 | 3 |
| | 2,153 | | 2,153 | 4 |
| | 30,356 | | 30,356 | 5 |
| | 4,105 | | 4,105 | 6 |
| | 76 | | 76 | 7 |
| | 44 | | 44 | 8 |
| | 126 | | 126 | 9 |
| | 790 | | 790 | 10 |
| | 3,943 | | 3,943 | 11 |
| | 632 | | 632 | 12 |
| | 95 | | 95 | 13 |
| | 76 | | 76 | 14 |
| | 720 | | 720 | 15 |
| | 278 | | 278 | 16 |
| | 3,709 | | 3,709 | 17 |
| | 2,597 | | 2,597 | 18 |
| | 196 | | 196 | 19 |
| | 1,472 | | 1,472 | 20 |
| | 43,446 | | 43,446 | 21 |
| | 23,445 | | 23,445 | 22 |
| | 5,081 | | 5,081 | 23 |
| | 4,461 | | 4,461 | 24 |
| | 3,040 | | 3,040 | 25 |
| | 1,264 | | 1,264 | 26 |
| | 56,982 | | 56,982 | 27 |
| | 11,128 | | 11,128 | 28 |
| | 6,439 | | 6,439 | 29 |
| | 1,953 | | 1,953 | 30 |
| | 7,915 | | 7,915 | 31 |
| | 1,938 | | 1,938 | 32 |
| | 481 | | 481 | 33 |
| | 9,038 | | 9,038 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 4,291 | | 4,291 | 1 |
| | 1,710 | | 1,710 | 2 |
| | 2,525 | | 2,525 | 3 |
| | 31,735 | | 31,735 | 4 |
| | 10,202 | | 10,202 | 5 |
| | 486 | | 486 | 6 |
| | 526 | | 526 | 7 |
| | 1,518 | | 1,518 | 8 |
| | 708 | | 708 | 9 |
| | 526 | | 526 | 10 |
| | 152 | | 152 | 11 |
| | 12,257 | | 12,257 | 12 |
| | 3,127 | | 3,127 | 13 |
| | 648 | | 648 | 14 |
| | 1,670 | | 1,670 | 15 |
| | 683 | | 683 | 16 |
| | 22,069 | | 22,069 | 17 |
| | 82,256 | | 82,256 | 18 |
| | 395,130 | | 395,130 | 19 |
| | 1,220 | | 1,220 | 20 |
| | 385 | | 385 | 21 |
| | 787,366 | | 787,366 | 22 |
| | 272,799 | | 272,799 | 23 |
| | 3,107 | | 3,107 | 24 |
| | 61 | | 61 | 25 |
| | 506 | | 506 | 26 |
| | 587 | | 587 | 27 |
| | 6,316 | | 6,316 | 28 |
| | 33,674 | | 33,674 | 29 |
| | 34,407 | | 34,407 | 30 |
| | 12,135 | | 12,135 | 31 |
| | 607,303 | | 607,303 | 32 |
| | 40,222 | | 40,222 | 33 |
| | 34,853 | | 34,853 | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

| Demand Charges ($) (k) | Energy Charges ($) (l) | (Other Charges) ($) (m) | Total Revenues ($) (k+l+m) (n) | Line No. |
|---|---|---|---|---|
| | 82,053 | | 82,053 | 1 |
| | 2,075 | | 2,075 | 2 |
| | 159,503 | | 159,503 | 3 |
| | 722 | | 722 | 4 |
| | 5,269 | | 5,269 | 5 |
| | 8,052 | | 8,052 | 6 |
| | 594 | | 594 | 7 |
| | 16,189 | | 16,189 | 8 |
| | 2,076 | | 2,076 | 9 |
| | 1,805 | | 1,805 | 10 |
| | 4,993 | | 4,993 | 11 |
| | 75,739 | | 75,739 | 12 |
| | 24,221 | | 24,221 | 13 |
| | 6,465 | | 6,465 | 14 |
| | 460 | | 460 | 15 |
| | 104,314 | | 104,314 | 16 |
| | 1,296 | | 1,296 | 17 |
| | 12,256 | | 12,256 | 18 |
| | | | | 19 |
| | | | | 20 |
| | | | | 21 |
| | | | | 22 |
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| | | | | 31 |
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| | | | | 33 |
| | | | | 34 |
| **10,338,047** | **31,733,406** | **0** | **42,071,453** | |

***Schedule Page: 328 Line No.: 1 Column: a***

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028.

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

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

***Schedule Page: 328 Line No.: 2 Column: a***

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2023.

***Schedule Page: 328 Line No.: 2 Column: e***

9, Open Access Transmission Tariff, Schedule 9 Network Integration Transmission Service

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

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

***Schedule Page: 328 Line No.: 3 Column: a***

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30, 2028.

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

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

***Schedule Page: 328 Line No.: 4 Column: a***

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

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

Legacy, contract prior to the Open Access Transmission Tariff

***Schedule Page: 328 Line No.: 5 Column: a***

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

***Schedule Page: 328 Line No.: 5 Column: e***

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

***Schedule Page: 328 Line No.: 6 Column: a***

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2021.

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

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

***Schedule Page: 328 Line No.: 7 Column: a***

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.: 8 Column: a***

The agreement between Idaho Power and Cycle Horseshoe Bend Wind, LLC has no expiration date and can be terminated by either party at any time.

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

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

***Schedule Page: 328 Line No.: 14 Column: e***

11, Open Access Transmission Tariff, Schedule 11 Unreserved Use Penalty

***Schedule Page: 328 Line No.: 16 Column: e***

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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) | 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 | Avangrid Renewables | OS | | | | | -100,674 | -100,674 |
| 2 | Avista Corp-WWP Div | NF | 4,551 | 4,551 | | 29,421 | | 29,421 |
| 3 | Avista Corp-WWP Div | SFP | 61,983 | 61,983 | | 199,955 | | 199,955 |
| 4 | Avista Corp-WWP Div | SFP | | | | 1,800 | | 1,800 |
| 5 | Bonneville Power Admin | LFP | 426,711 | 426,711 | | 2,810,869 | | 2,810,869 |
| 6 | Bonneville Power Admin | SFP | 8,695 | 8,695 | | 40,348 | | 40,348 |
| 7 | Bonneville Power Admin | NF | 882 | 882 | | 4,767 | | 4,767 |
| 8 | Bonneville Power Admin | OS | | | | | 12,932 | 12,932 |
| 9 | Bonneville Power Admin | OS | | | | | 569,186 | 569,186 |
| 10 | Bonneville Power Admin | OS | 3,621 | 3,621 | | | | |
| 11 | Bonneville Power Admin | OS | 58,775 | 58,775 | | | | |
| 12 | Bonneville Power Admin | OS | 26,280 | 26,280 | | | | |
| 13 | Bonneville Power Admin | OS | 6,282 | 6,282 | | | | |
| 14 | Bonneville Power Admin | OS | 700 | 700 | | | | |
| 15 | Bonneville Power Admin | OS | 3,560 | 3,560 | | | | |
| 16 | Bonneville Power Admin | OS | 320 | 320 | | | | |
| | TOTAL | | 630,143 | 630,143 | | 4,371,439 | 196,960 | 4,568,399 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Bonneville Power Admin | OS | 601 | 601 | | | 2,400 | 2,400 |
| 2 | Exelon Generation Co | OS | | | | | -32,522 | -32,522 |
| 3 | NV Energy | SFP | 1,011 | 1,011 | | 12,990 | | 12,990 |
| 4 | NV Energy | NF | 3,709 | 3,709 | | 20,235 | | 20,235 |
| 5 | NV Energy | OS | | | | | 4,581 | 4,581 |
| 6 | NorthWestern Energy | SFP | 2,334 | 2,334 | | 16,832 | | 16,832 |
| 7 | NorthWestern Energy | NF | 61 | 61 | | 264 | | 264 |
| 8 | NorthWestern Energy | OS | | | | | 824 | 824 |
| 9 | NorthWestern Energy | AD | | | | | -32 | -32 |
| 10 | PacifiCorp Inc. | LFP | 14,622 | 14,622 | | 1,045,452 | | 1,045,452 |
| 11 | PacifiCorp Inc. | SFP | 5,435 | 5,435 | | 47,713 | | 47,713 |
| 12 | PacifiCorp Inc. | NF | 10 | 10 | | 746 | | 746 |
| 13 | PacifiCorp Inc. | OS | | | | | 46,174 | 46,174 |
| 14 | PacifiCorp Inc. | AD | | | | | -285 | -285 |
| 15 | PacifiCorp Inc. | AD | | | | | 87,366 | 87,366 |
| 16 | PacifiCorp Inc. | AD | | | | | 2,112 | 2,112 |
| | TOTAL | | 630,143 | 630,143 | | 4,371,439 | 196,960 | 4,568,399 |

## 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 | Powerex Corp. | OS | | | | | -313,950 | -313,950 |
| 2 | Puget Sound Energy, Inc | SFP | | | | 34,325 | | 34,325 |
| 3 | Seattle City Light | SFP | | | | 875 | | 875 |
| 4 | Shell Energy N. America | SFP | | | | 7,368 | | 7,368 |
| 5 | Shell Energy N. America | OS | | | | | -1,057 | -1,057 |
| 6 | Snohomish County PUD | SFP | | | | 91,631 | | 91,631 |
| 7 | Tacoma Power | SFP | | | | 5,400 | | 5,400 |
| 8 | The Energy Authority | SFP | | | | 448 | | 448 |
| 9 | TransAlta Energy U.S. | OS | | | | | -80,095 | -80,095 |
| 10 | | | | | | | | |
| 11 | | | | | | | | |
| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| | TOTAL | | 630,143 | 630,143 | | 4,371,439 | 196,960 | 4,568,399 |

***Schedule Page: 332 Line No.: 1 Column: b***
Resale Transmission

***Schedule Page: 332 Line No.: 4 Column: b***
BPAT is provider for capacity reassignment settled with Avista.

***Schedule Page: 332 Line No.: 5 Column: b***
Contract Expiration Date 12/31/2021

***Schedule Page: 332 Line No.: 8 Column: b***
Spinning/supplemental reserves

***Schedule Page: 332 Line No.: 9 Column: b***
Ancillary Services

***Schedule Page: 332 Line No.: 10 Column: b***
BPAT is provider for capacity reassignment settled with Shell.

***Schedule Page: 332 Line No.: 11 Column: b***
BPAT is provider for capacity reassignment settled with Snohomish County PUD.

***Schedule Page: 332 Line No.: 12 Column: b***
BPAT is provider for capacity reassignment settled with Puget Sound Energy.

***Schedule Page: 332 Line No.: 13 Column: b***
BPAT is provider for capacity reassignment settled with Avista.

***Schedule Page: 332 Line No.: 14 Column: b***
BPAT is provider for capacity reassignment settled with Seattle City Light.

***Schedule Page: 332 Line No.: 15 Column: b***
BPAT is provider for capacity reassignment settled with Tacoma Power.

***Schedule Page: 332 Line No.: 16 Column: b***
BPAT is provider for capacity reassignment settled with The Energy Authority.

***Schedule Page: 332.1 Line No.: 1 Column: b***
Transmission Resale

***Schedule Page: 332.1 Line No.: 2 Column: b***
Resale Transmission

***Schedule Page: 332.1 Line No.: 5 Column: b***
Ancillary Services

***Schedule Page: 332.1 Line No.: 8 Column: b***
Ancillary Services

***Schedule Page: 332.1 Line No.: 9 Column: b***
Refunded PTP from July 2014

***Schedule Page: 332.1 Line No.: 10 Column: b***
Contract Expiration Date 05/31/2019

***Schedule Page: 332.1 Line No.: 13 Column: b***
Ancillary Services

***Schedule Page: 332.1 Line No.: 14 Column: b***
PTP 2015 True-Up

***Schedule Page: 332.1 Line No.: 15 Column: b***
2016 PTP True-Up

***Schedule Page: 332.1 Line No.: 16 Column: b***
December 2016 correction

***Schedule Page: 332.2 Line No.: 1 Column: b***
Ancillary Services

***Schedule Page: 332.2 Line No.: 2 Column: b***
BPAT is provider for capacity reassignment settled with Puget Sound Energy

***Schedule Page: 332.2 Line No.: 3 Column: b***
BPAT is provider for capacity reassignment settled with Seattle City Light

***Schedule Page: 332.2 Line No.: 4 Column: b***
BPAT is provider for capacity reassignment settled with Shell Energy

***Schedule Page: 332.2 Line No.: 5 Column: b***
Ancillary Services

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***Schedule Page: 332.2 Line No.: 6 Column: b***

BPAT is provider for capacity reassignment settled with Snohomish County PUD

***Schedule Page: 332.2 Line No.: 7 Column: b***

BPAT is provider for capacity reassignment settled with Tacoma Power

***Schedule Page: 332.2 Line No.: 9 Column: b***

Ancillary Services

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

| Line No. | Description (a) | Amount (b) |
|---|---|---|
| 1 | Industry Association Dues | 515,878 |
| 2 | Nuclear Power Research Expenses | |
| 3 | Other Experimental and General Research Expenses | |
| 4 | Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities | 1,665,574 |
| 5 | Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000 | 90,843 |
| 6 | | |
| 7 | Director Fees and Expenses: | |
| 8 | Annette Elg | 66,907 |
| 9 | Christine King | 87,961 |
| 10 | Dennis Johnson | 70,290 |
| 11 | J Lamont Keen | 64,350 |
| 12 | Judith Johansen | 78,358 |
| 13 | Richard Dahl | 91,575 |
| 14 | Richard Navarro | 76,230 |
| 15 | Robert Tintsman | 170,703 |
| 16 | Ronald Jibson | 72,359 |
| 17 | Thomas Carlile | 76,230 |
| 18 | Director travel and lodging | 34,158 |
| 19 | | |
| 20 | Corporate Memberships and Subscriptions: | |
| 21 | Arizona State University | 41,666 |
| 22 | Associated Taxpayers of Idaho | 26,000 |
| 23 | Assocation of Idaho Cities | 5,000 |
| 24 | Boise Valley Eco | 20,000 |
| 25 | Business Plus | 5,000 |
| 26 | Chartwell Inc. | 34,888 |
| 27 | Idaho Association of Commerce & Industry | 15,000 |
| 28 | Idaho Mining Association | 6,500 |
| 29 | National Association of Directors | 8,075 |
| 30 | National Hydropower Association | 36,935 |
| 31 | Pacific NW Utilites | 42,747 |
| 32 | S&P Global | 29,261 |
| 33 | Wester Energy Institute | 30,962 |
| 34 | Misc Memberships under $2,000 | 7,444 |
| 35 | | |
| 36 | Chambers of Commerce & Other Civic Organizations | 85,547 |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | | |
| 44 | | |
| 45 | | |
| 46 | TOTAL | 3,556,441 |

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

| Recipient | Purpose | Amount |
|---|---|---|
| American Stock Transfer & Trust | Mgmt Services | $ 60,407 |
| Bloomberg Finance LP | Misc Expense | 22,597 |
| Broadridge Financial Solutions | Misc Expense | 50,438 |
| Deutsche Bank | Broker Fees | 30,000 |
| E Source | Mgmt Services | 27,743 |
| Market Intelligence Group | Mgmt Services | 20,691 |
| Moody's Analytics | Mgmt Services | 35,590 |
| NASDAQ Corp Solutions | Mgmt Services | 51,157 |
| New York Stock Exchange | Listing Services | 58,929 |
| Payroll Related Expenses | Misc Expense | 168,067 |
| PR Newswire | Misc Expense | 16,575 |
| Rivel Research Group | Mgmt Services | 15,840 |
| Stock Based Compensation | Misc Expense | 989,313 |
| Wells Fargo Shareowner Services | Mgmt Services | 118,227 |
| | | ------- |
| | | $ 1,665,574 |

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

| Recipient | Purpose | Amount |
|---|---|---|
| Bank of New York | Revenue Bonds | $ 12,925 |
| Investis, Inc. | Website Design | 37,457 |
| Payroll Related Expense | Misc Expense | 16,651 |
| Miscellaneous under $5,000 | Misc Expense | 23,810 |
| | | ------ |
| | | $ 90,843 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

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

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

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

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

### A. Summary of Depreciation and Amortization Charges

| Line No. | Functional Classification (a) | Depreciation Expense (Account 403) (b) | Depreciation Expense for Asset Retirement Costs (Account 403.1) (c) | Amortization of Limited Term Electric Plant (Account 404) (d) | Amortization of Other Electric Plant (Acc 405) (e) | Total (f) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant | | | 6,243,722 | | 6,243,722 |
| 2 | Steam Production Plant | 45,281,481 | 566,665 | | | 45,848,146 |
| 3 | Nuclear Production Plant | | | | | |
| 4 | Hydraulic Production Plant-Conventional | 15,551,612 | | | | 15,551,612 |
| 5 | Hydraulic Production Plant-Pumped Storage | | | | | |
| 6 | Other Production Plant | 16,450,729 | | | | 16,450,729 |
| 7 | Transmission Plant | 22,154,895 | | | | 22,154,895 |
| 8 | Distribution Plant | 40,727,549 | | | | 40,727,549 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 10 | General Plant | 13,792,320 | | | | 13,792,320 |
| 11 | Common Plant-Electric | | | | | |
| 12 | TOTAL | 153,958,586 | 566,665 | 6,243,722 | | 160,768,973 |

### B. Basis for Amortization Charges

| Acct 404 | Balance 1/1/2017 | 2017 Amortization | Balance 12/31/2017 | Remaining Months |
|---|---|---|---|---|
| (1) | 12,000 | 12,000 | - | - |
| (2) | 9,257,436 | 520,449 | 8,736,987 | - |
| (3) | 4,873,436 | 189,257 | 4,684,179 | 296 |
| (4) | 9,768,866 | 5,189,488 | 12,134,210 | - |
| (5) | 3,172,199 | 287,899 | 2,884,300 | 120 |
| (6) | 185,769 | 16,112 | 169,657 | 36 |
| (7) | 1,128,967 | 28,517 | 1,797,458 | - |
| Total | 28,398,673 | 6,243,722 | 30,406,791 | |

(1) Shoshone-Bannock Tribe License & Use Agreement. (New five year advance payment starting January 2018, with a December 31, 2022 termination date.)
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period; licenses expire 07/31/34 and 02/28/35).
(3) Swan Falls Relicensing Costs (Amortized over a 30 year license period, license expires August 31, 2042).
(4) Computer Software packages (Amortized over a 62 month period).
(5) Shoshone-Bannock Right of Way (Termination date 12/31/27).
(6) Boardman Retrofit Tech Analysis (Scheduled decommission date 12/31/20).
(7) FERC License Compliance Costs (Termination date will be expiration date of the applicable 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 649 | 75.00 | | 5.60 | R4.0 | 17.90 |
| 13 | 311.00 | 154,464 | 100.00 | -9.00 | 3.09 | S0.5 | 17.90 |
| 14 | 312.10 | 193,745 | 70.00 | -5.00 | 2.79 | S1.0 | 18.10 |
| 15 | 312.20 | 559,584 | 53.00 | -8.00 | 4.25 | R1.5 | 17.00 |
| 16 | 312.30 | 4,341 | 35.00 | 10.00 | 2.65 | R3.0 | 13.50 |
| 17 | 314.00 | 169,860 | 45.00 | -7.00 | 4.80 | S0.5 | 16.50 |
| 18 | 315.00 | 73,750 | 60.00 | -3.00 | 3.19 | S1.5 | 16.80 |
| 19 | 316.00 | 13,727 | 35.00 | 2.00 | 5.36 | S0.0 | 14.60 |
| 20 | 316.10 | 329 | 13.00 | 15.00 | 7.92 | L2.0 | 5.40 |
| 21 | 316.40 | 250 | 13.00 | 15.00 | 0.92 | L2.0 | |
| 22 | 316.50 | 1,366 | 13.00 | 15.00 | 4.12 | L2.0 | 11.80 |
| 23 | 316.60 | 387 | | | 3.24 | | |
| 24 | 316.70 | 144 | 21.00 | 15.00 | 0.81 | S1.0 | 12.20 |
| 25 | 316.80 | 3,936 | 20.00 | 25.00 | 4.54 | O1.0 | 17.80 |
| 26 | 316.90 | 14 | 35.00 | 15.00 | 2.44 | S1.0 | 30.60 |
| 27 | 317.00 | 14,890 | | | | | |
| 28 | **Subtotal Steam** | 1,191,436 | | | | | |
| 29 | 331.00 | 196,243 | 120.00 | -25.00 | 2.08 | R2.5 | 35.80 |
| 30 | 332.10 | 19,461 | 120.00 | -20.00 | 0.98 | S1.5 | 46.20 |
| 31 | 332.20 | 248,612 | 120.00 | -20.00 | 1.80 | S1.5 | 31.20 |
| 32 | 332.30 | 5,472 | | | 1.15 | Square | 55.10 |
| 33 | 333.00 | 260,309 | 100.00 | -10.00 | 1.92 | R2.5 | 30.60 |
| 34 | 334.00 | 62,465 | 65.00 | -10.00 | 2.82 | R1.5 | 27.80 |
| 35 | 335.00 | 25,106 | 90.00 | -5.00 | 2.18 | R2.0 | 31.20 |
| 36 | 335.10 | 88 | 15.00 | | 7.92 | Square | 7.90 |
| 37 | 335.20 | 398 | 20.00 | | 0.80 | Square | 9.20 |
| 38 | 335.30 | 400 | 5.00 | | 14.42 | Square | 2.50 |
| 39 | 336.00 | 10,882 | 100.00 | | 2.58 | R3.0 | 22.70 |
| 40 | Subtotal Hydro | 829,436 | | | | | |
| 41 | 341.00 | 143,333 | | | 2.72 | Square | 32.80 |
| 42 | 342.00 | 10,538 | 50.00 | | 2.81 | S2.5 | 28.70 |
| 43 | 343.00 | 224,538 | 40.00 | | 3.18 | R2.0 | 26.00 |
| 44 | 344.00 | 66,532 | 50.00 | | 2.45 | S2.0 | 28.40 |
| 45 | 345.00 | 91,478 | 55.00 | | 2.91 | R2.0 | 29.30 |
| 46 | 346.00 | 6,389 | 35.00 | | 3.24 | R2.5 | 24.00 |
| 47 | Subtotal Other | 542,808 | | | | | |
| 48 | 350.20 | 32,501 | 100.00 | | 0.89 | R4.0 | 85.20 |
| 49 | 350.22 | 199 | 30.00 | | 3.33 | | |
| 50 | 352.00 | 80,264 | 65.00 | -33.00 | 1.88 | R3.0 | 53.20 |

## 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 | 428,949 | 52.00 | -10.00 | 1.97 | S0.5 | 42.00 |
| 13 | 354.00 | 206,553 | 80.00 | -10.00 | 1.07 | R4.0 | 71.10 |
| 14 | 355.00 | 182,124 | 65.00 | -80.00 | 2.64 | R1.5 | 53.90 |
| 15 | 355.10 | 1,212 | 10.00 | | 10.00 | | |
| 16 | 356.00 | 226,621 | 74.00 | -50.00 | 1.87 | R1.5 | 62.30 |
| 17 | 359.00 | 390 | 65.00 | | 0.91 | R2.5 | 33.30 |
| 18 | Subtotal Transmission | 1,158,813 | | | | | |
| 19 | 360.22 | 853 | 30.00 | | 3.33 | | |
| 20 | 361.00 | 37,463 | 70.00 | -50.00 | 2.17 | R3.0 | 54.40 |
| 21 | 362.00 | 237,332 | 55.00 | -6.00 | 1.85 | R1.5 | 42.90 |
| 22 | 364.00 | 261,432 | 58.00 | -50.00 | 2.17 | R1.5 | 44.10 |
| 23 | 364.10 | 3,950 | 12.00 | | 8.34 | | |
| 24 | 365.00 | 136,070 | 49.00 | -30.00 | 2.65 | R1.0 | 34.40 |
| 25 | 366.00 | 50,759 | 65.00 | -25.00 | 1.89 | R2.5 | 49.10 |
| 26 | 367.00 | 258,500 | 50.00 | -11.00 | 1.90 | R1.5 | 39.40 |
| 27 | 368.00 | 560,034 | 42.00 | -7.00 | 2.17 | R0.5 | 34.80 |
| 28 | 369.00 | 60,786 | 55.00 | -40.00 | 1.58 | R1.5 | 43.40 |
| 29 | 370.00 | 16,413 | 30.00 | -5.00 | 2.05 | O1.0 | 25.70 |
| 30 | 370.10 | 73,608 | 18.00 | -5.00 | 5.39 | R1.5 | 14.00 |
| 31 | 371.20 | 3,057 | 21.00 | -5.00 | 2.88 | R1.0 | 14.70 |
| 32 | 373.20 | 4,527 | 40.00 | -30.00 | 1.73 | R1.0 | 29.00 |
| 33 | 374.00 | 143 | | | | | |
| 34 | Subtotal Distribution | 1,704,927 | | | | | |
| 35 | 390.11 | 30,902 | 90.00 | -3.00 | 2.08 | S1.0 | 33.20 |
| 36 | 390.12 | 89,751 | 55.00 | -3.00 | 2.11 | R2.0 | 38.80 |
| 37 | 391.10 | 15,370 | 20.00 | | 4.00 | Square | 12.30 |
| 38 | 391.20 | 24,169 | 5.00 | | 20.00 | Square | 2.70 |
| 39 | 391.21 | 5,374 | 8.00 | | 12.50 | Square | 3.50 |
| 40 | 392.10 | 804 | 13.00 | 15.00 | 7.07 | L2.0 | 9.30 |
| 41 | 392.30 | 4,563 | 15.00 | 40.00 | 4.13 | S2.5 | 9.70 |
| 42 | 392.40 | 24,592 | 13.00 | 15.00 | 6.20 | L2.0 | 8.50 |
| 43 | 392.50 | 1,355 | 13.00 | 15.00 | 6.34 | L2.0 | 8.90 |
| 44 | 392.60 | 42,974 | 21.00 | 15.00 | 3.95 | S1.0 | 14.00 |
| 45 | 392.70 | 8,515 | 21.00 | 15.00 | 4.16 | S1.0 | 12.30 |
| 46 | 392.90 | 5,346 | 35.00 | 15.00 | 2.24 | S1.0 | 24.30 |
| 47 | 393.00 | 2,948 | 25.00 | | 4.00 | Square | 17.40 |
| 48 | 394.00 | 10,438 | 20.00 | | 5.00 | Square | 12.40 |
| 49 | 395.00 | 13,869 | 20.00 | | 5.00 | Square | 10.60 |
| 50 | 396.00 | 16,265 | 20.00 | 25.00 | 2.97 | O1.0 | 16.70 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

| Line No. | Account No. (a) | Depreciable Plant Base (In Thousands) (b) | Estimated Avg. Service Life (c) | Net Salvage (Percent) (d) | Applied Depr. rates (Percent) (e) | Mortality Curve Type (f) | Average Remaining Life (g) |
|---|---|---|---|---|---|---|---|
| 12 | 397.10 | 2,947 | 15.00 | | 6.67 | Square | 4.70 |
| 13 | 397.20 | 28,280 | 15.00 | | 6.67 | Square | 8.10 |
| 14 | 397.30 | 3,530 | 15.00 | | 6.67 | Square | 9.70 |
| 15 | 397.40 | 19,379 | 15.00 | | 6.02 | Square | 13.10 |
| 16 | 398.00 | 6,979 | 15.00 | | 6.67 | Square | 8.60 |
| 17 | Subtotal General | 358,350 | | | | | |
| 18 | **Total Plant** | 5,785,770 | | | | | |
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***Schedule Page: 336 Line No.: 28 Column: a***

**(Column: c,d,f, g)** Plant accounts 31020 through 31650 and 31670 through 31690 are presented for Jim Bridger facility only. This data is provided by the most recent depreciation study; Jim Bridger was the only thermal production facility included in the depreciation study. Plant account 31660 is associated with Valmy facility only. Valmy was not part of the 2016 depreciation study, as Valmy has been reviewed for decommissioning within regulatory order #33771. There is no data for estimated service life, net salvage percentage, or mortality curve.

**(Column: e)** An average plant balance was used in computing these rates by plant account.

***Schedule Page: 336.2 Line No.: 18 Column: a***

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1,1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, service lives, net salvage and remaining lives indicated are on a composite basis. Effective April 1, 1993 all depreciable plant is being depreciated using the straight-line remaining life method.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## REGULATORY COMMISSION EXPENSES

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

| Line No. | Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a) | Assessed by Regulatory Commission (b) | Expenses of Utility (c) | Total Expense for Current Year (b) + (c) (d) | Deferred in Account 182.3 at Beginning of Year (e) |
|---|---|---|---|---|---|
| 1 | Federal Energy Regulatory Commission: | | | | |
| 2 | Annual admin charges assessed by FERC | 3,585,160 | | 3,585,160 | |
| 3 | | | | | |
| 4 | General Regulatory Expenses and | | | | |
| 5 | Various other Dockets | | 644 | 644 | |
| 6 | | | | | |
| 7 | Oregon Hydro - Fees Amortization | 158,501 | | 158,501 | |
| 8 | | | | | |
| 9 | Regulatory Commission Expenses - Idaho | | | | |
| 10 | Rate Case - Misc expenses | | 146,746 | 146,746 | 80,210 |
| 11 | | | | | |
| 12 | Regulatory Commission Expenses - Oregon | | | | |
| 13 | Rate Case - Misc expenses | | 7,093 | 7,093 | |
| 14 | General Regulatory | | 352,760 | 352,760 | |
| 15 | Other OPUC expenses | | 9,805 | 9,805 | |
| 16 | | | | | |
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| 45 | | | | | |
| 46 | TOTAL | 3,743,661 | 517,048 | 4,260,709 | 80,210 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

REGULATORY COMMISSION EXPENSES (Continued)

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

| EXPENSES INCURRED DURING YEAR | | | | AMORTIZED DURING YEAR | | | |
|---|---|---|---|---|---|---|---|
| CURRENTLY CHARGED TO | | | Deferred to Account 182.3 | Contra Account | Amount | Deferred in Account 182.3 End of Year | Line No. |
| Department (f) | Account No. (g) | Amount (h) | (i) | (j) | (k) | (l) | |
| | | | | | | | 1 |
| Electric | 928 | 3,585,160 | | | | | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| Electric | 928 | 644 | | | | | 5 |
| | | | | | | | 6 |
| Electric | 928 | 158,501 | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| Electric | 928 | 1,200 | 113,171 | 928203 | 145,546 | 47,835 | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| Electric | 928 | 7,093 | | | | | 13 |
| Electric | 928 | 352,760 | | | | | 14 |
| Electric | 928 | 9,805 | | | | | 15 |
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| | | 4,115,163 | 113,171 | | 145,546 | 47,835 | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

| Line No. | Classification (a) | Description (b) |
|---|---|---|
| 1 | Idaho Power did not incur any Research and | |
| 2 | Development expenditures in 2017. | |
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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 | | Unamortized Accumulation (g) | Line No. |
|---|---|---|---|---|---|
| | | Account (e) | Amount (f) | | |
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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 | 04/18/2018 | End of 2017/Q4 |

## DISTRIBUTION OF SALARIES AND WAGES

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

| Line No. | Classification (a) | Direct Payroll Distribution (b) | Allocation of Payroll charged for Clearing Accounts (c) | Total (d) |
|---|---|---|---|---|
| 1 | Electric | | | |
| 2 | Operation | | | |
| 3 | Production | 20,927,127 | | |
| 4 | Transmission | 6,658,812 | | |
| 5 | Regional Market | | | |
| 6 | Distribution | 18,760,177 | | |
| 7 | Customer Accounts | 8,817,654 | | |
| 8 | Customer Service and Informational | 4,665,208 | | |
| 9 | Sales | | | |
| 10 | Administrative and General | 68,823,822 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 128,652,800 | | |
| 12 | Maintenance | | | |
| 13 | Production | 4,274,947 | | |
| 14 | Transmission | 2,892,129 | | |
| 15 | Regional Market | | | |
| 16 | Distribution | 7,267,021 | | |
| 17 | Administrative and General | 1,124,057 | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 15,558,154 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | 25,202,074 | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 9,550,941 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 26,027,198 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 8,817,654 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 4,665,208 | | |
| 26 | Sales (Transcribe from line 9) | | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 69,947,879 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 144,210,954 | | 144,210,954 |
| 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

DISTRIBUTION OF SALARIES AND WAGES (Continued)

| Line No. | Classification (a) | Direct Payroll Distribution (b) | Allocation of Payroll charged for Clearing Accounts (c) | Total (d) |
|---|---|---|---|---|
| 48 | Distribution | | | |
| 49 | Administrative and General | | | |
| 50 | TOTAL Maint. (Enter Total of lines 43 thru 49) | | | |
| 51 | Total Operation and Maintenance | | | |
| 52 | Production-Manufactured Gas (Enter Total of lines 31 and 43) | | | |
| 53 | Production-Natural Gas (Including Expl. and Dev.) (Total lines 32, | | | |
| 54 | Other Gas Supply (Enter Total of lines 33 and 45) | | | |
| 55 | Storage, LNG Terminaling and Processing (Total of lines 31 thru | | | |
| 56 | Transmission (Lines 35 and 47) | | | |
| 57 | Distribution (Lines 36 and 48) | | | |
| 58 | Customer Accounts (Line 37) | | | |
| 59 | Customer Service and Informational (Line 38) | | | |
| 60 | Sales (Line 39) | | | |
| 61 | Administrative and General (Lines 40 and 49) | | | |
| 62 | TOTAL Operation and Maint. (Total of lines 52 thru 61) | | | |
| 63 | Other Utility Departments | | | |
| 64 | Operation and Maintenance | | | |
| 65 | TOTAL All Utility Dept. (Total of lines 28, 62, and 64) | 144,210,954 | | 144,210,954 |
| 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 | Store Expense | 4,772,395 | | 4,772,395 |
| 79 | Other Clearing Accounts | 3,424,312 | | 3,424,312 |
| 80 | Construction Work in Progress | 58,547,235 | | 58,547,235 |
| 81 | Other Work in Progress | 3,903,156 | | 3,903,156 |
| 82 | Other Accounts | 5,191,679 | | 5,191,679 |
| 83 | Indirect Loading | | 48,797,728 | 48,797,728 |
| 84 | | | | |
| 85 | | | | |
| 86 | | | | |
| 87 | | | | |
| 88 | | | | |
| 89 | | | | |
| 90 | | | | |
| 91 | | | | |
| 92 | | | | |
| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 75,838,777 | 48,797,728 | 124,636,505 |
| 96 | TOTAL SALARIES AND WAGES | 220,049,731 | 48,797,728 | 268,847,459 |

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**Schedule Page: 354 Line No.: 83 Column: a**

Amount reported is total amount of indirect loading. The loading is allocated to departments based on labor charges.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## 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 | | | 598,161 | | | |
| 2 | Reactive Supply and Voltage | | | 22,605 | | | |
| 3 | Regulation and Frequency Response | | | | 3,051,238 | KW | 298,869 |
| 4 | Energy Imbalance | | | | 5,470 | KWH | 703,539 |
| 5 | Operating Reserve - Spinning | | | 7,469 | 4,233,136 | KW | 416,636 |
| 6 | Operating Reserve - Supplement | | | 5,463 | 4,274,576 | KW | 418,695 |
| 7 | Other | | | | | | |
| 8 | Total (Lines 1 thru 7) | | | 633,698 | 11,564,420 | | 1,837,739 |

***Schedule Page: 398 Line No.: 1 Column: b***

Information not available - Idaho Power does not systematically record the number of units related to ancillary services purchased.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | Monthly Peak MW - Total<br>(b) | Day of Monthly Peak<br>(c) | Hour of Monthly Peak<br>(d) | Firm Network Service for Self<br>(e) | Firm Network Service for Others<br>(f) | Long-Term Firm Point-to-point Reservations<br>(g) | Other Long-Term Firm Service<br>(h) | Short-Term Firm Point-to-point Reservation<br>(i) | Other Service<br>(j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | 3,736 | 17 | 800 | 2,177 | 261 | 973 | | 325 | |
| 2 | February | 3,288 | 14 | 800 | 1,598 | 219 | 973 | | 498 | |
| 3 | March | 2,890 | 30 | 2100 | 1,309 | 185 | 973 | | 423 | |
| 4 | Total for Quarter 1 | | | | 5,084 | 665 | 2,919 | | 1,246 | |
| 5 | April | 2,813 | 28 | 800 | 1,066 | 178 | 973 | | 596 | |
| 6 | May | 3,840 | 31 | 1700 | 2,031 | 287 | 973 | | 549 | |
| 7 | June | 4,468 | 26 | 1600 | 2,724 | 357 | 973 | | 414 | |
| 8 | Total for Quarter 2 | | | | 5,821 | 822 | 2,919 | | 1,559 | |
| 9 | July | 4,713 | 8 | 1900 | 3,163 | 352 | 973 | | 225 | |
| 10 | August | 4,464 | 2 | 1900 | 2,934 | 339 | 973 | | 218 | |
| 11 | September | 3,918 | 3 | 1800 | 2,445 | 283 | 973 | | 217 | |
| 12 | Total for Quarter 3 | | | | 8,542 | 974 | 2,919 | | 660 | |
| 13 | October | 2,886 | 3 | 900 | 1,442 | 185 | 973 | | 286 | |
| 14 | November | 3,011 | 8 | 800 | 1,555 | 199 | 973 | | 284 | |
| 15 | December | 3,288 | 15 | 900 | 1,506 | 218 | 973 | | 591 | |
| 16 | Total for Quarter 4 | | | | 4,503 | 602 | 2,919 | | 1,161 | |
| 17 | Total Year to Date/Year | | | | 23,950 | 3,063 | 11,676 | | 4,626 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## ELECTRIC ENERGY ACCOUNT

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

| Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|
| 1 | SOURCES OF ENERGY | |
| 2 | Generation (Excluding Station Use): | |
| 3 | Steam | 3,284,013 |
| 4 | Nuclear | |
| 5 | Hydro-Conventional | 8,900,059 |
| 6 | Hydro-Pumped Storage | |
| 7 | Other | 1,503,310 |
| 8 | Less Energy for Pumping | |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 13,687,382 |
| 10 | Purchases | 4,293,616 |
| 11 | Power Exchanges: | |
| 12 | Received | 228,341 |
| 13 | Delivered | 259,185 |
| 14 | Net Exchanges (Line 12 minus line 13) | -30,844 |
| 15 | Transmission For Other (Wheeling) | |
| 16 | Received | 6,832,886 |
| 17 | Delivered | 6,820,026 |
| 18 | Net Transmission for Other (Line 16 minus line 17) | 12,860 |
| 19 | Transmission By Others Losses | |
| 20 | TOTAL (Enter Total of lines 9, 10, 14, 18 and 19) | 17,963,014 |

| Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|
| 21 | DISPOSITION OF ENERGY | |
| 22 | Sales to Ultimate Consumers (Including Interdepartmental Sales) | 14,570,954 |
| 23 | Requirements Sales for Resale (See instruction 4, page 311.) | |
| 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | 2,135,649 |
| 25 | Energy Furnished Without Charge | |
| 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | |
| 27 | Total Energy Losses | 1,256,411 |
| 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 17,963,014 |

***Schedule Page: 401 Line No.: 18 Column: b***

Page 329 column I differs from page 401 by 12,860 MWH, reported for Lucky Peak variation and BPA energy imbalance schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only, 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Total Monthly Energy | Monthly Non-Requirments Sales for Resale & Associated Losses | MONTHLY PEAK | | |
|---|---|---|---|---|---|---|
| | | | | Megawatts (See Instr. 4) | Day of Month | Hour |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 29 | January | 1,479,401 | 22,381 | 2,527 | 6 | 9 AM |
| 30 | February | 1,390,680 | 258,738 | 2,203 | 2 | 7 PM |
| 31 | March | 1,568,423 | 472,711 | 1,985 | 2 | 8 AM |
| 32 | April | 1,486,012 | 467,608 | 1,791 | 4 | 8 AM |
| 33 | May | 1,512,091 | 228,398 | 2,631 | 30 | 6 PM |
| 34 | June | 1,665,666 | 139,852 | 3,139 | 26 | 4 PM |
| 35 | July | 1,911,087 | 20,673 | 3,422 | 7 | 5 PM |
| 36 | August | 1,712,283 | 44,397 | 3,153 | 2 | 6 PM |
| 37 | September | 1,390,726 | 150,917 | 2,812 | 1 | 6 PM |
| 38 | October | 1,201,145 | 116,726 | 1,774 | 16 | 8 AM |
| 39 | November | 1,160,655 | 70,683 | 1,964 | 30 | 8 AM |
| 40 | December | 1,485,411 | 142,565 | 2,181 | 13 | 7 PM |
| 41 | TOTAL | 17,963,580 | 2,135,649 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/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) | 712 | | | 60 | | |
| 7 | Plant Hours Connected to Load | 8760 | | | 3905 | | |
| 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 | 2893201000 | | | 162076000 | | |
| 13 | Cost of Plant: Land and Land Rights | 509671 | | | 106610 | | |
| 14 | Structures and Improvements | 70169218 | | | 12607486 | | |
| 15 | Equipment Costs | 627633929 | | | 63810772 | | |
| 16 | Asset Retirement Costs | 9832782 | | | 5046008 | | |
| 17 | Total Cost | 708145600 | | | 81570876 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 919.0728 | | | 1270.5744 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 166605 | | | 375778 | | |
| 20 | Fuel | 92007202 | | | 4156501 | | |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | | | 0 | | |
| 22 | Steam Expenses | 5531161 | | | 677945 | | |
| 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 | 8747253 | | | 806543 | | |
| 27 | Rents | 328946 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 23430 | | | 31798 | | |
| 30 | Maintenance of Structures | 94 | | | 40380 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 7074749 | | | 188557 | | |
| 32 | Maintenance of Electric Plant | 2340314 | | | 1519055 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 5766079 | | | 56782 | | |
| 34 | Total Production Expenses | 121985833 | | | 7853339 | | |
| 35 | Expenses per Net KWh | 0.0422 | | | 0.0485 | | |
| 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 | 1634369 | 6603 | 0 | 97989 | 1824 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 9183 | 140000 | 0 | 8596 | 138800 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 54.681 | 82.711 | 0.000 | 36.966 | 79.025 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 55.903 | 65.932 | 0.000 | 40.864 | 76.359 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 3.015 | 11.213 | 0.000 | 2.353 | 13.098 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.032 | 0.000 | 0.000 | 0.026 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 10487.000 | 0.000 | 0.000 | 10567.000 | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | | | 247 | | | 193 | 6 |
| | | 2771 | | | 431 | | | 605 | 7 |
| | | 0 | | | 261 | | | 164 | 8 |
| | | 0 | | | 0 | | | 0 | 9 |
| | | 0 | | | 0 | | | 0 | 10 |
| | | 0 | | | 6 | | | 5 | 11 |
| | | 228736000 | | | 66191000 | | | 86409000 | 12 |
| | | 1106140 | | | 402745 | | | 0 | 13 |
| | | 71687061 | | | 6088861 | | | 1830493 | 14 |
| | | 329988873 | | | 100556351 | | | 61237796 | 15 |
| | | 11102 | | | 0 | | | 0 | 16 |
| | | 402793176 | | | 107047957 | | | 63068289 | 17 |
| | | 1420.7872 | | | 395.1567 | | | 364.9785 | 18 |
| | | 436337 | | | 144745 | | | 7567 | 19 |
| | | 11729960 | | | 3976764 | | | 3409554 | 20 |
| | | 0 | | | 0 | | | 0 | 21 |
| | | 2292329 | | | 0 | | | 0 | 22 |
| | | 0 | | | 0 | | | 0 | 23 |
| | | 0 | | | 0 | | | 0 | 24 |
| | | 1396032 | | | 395123 | | | 310116 | 25 |
| | | 2141109 | | | 281259 | | | 134431 | 26 |
| | | 0 | | | 0 | | | 0 | 27 |
| | | 0 | | | 0 | | | 0 | 28 |
| | | 0 | | | 0 | | | 0 | 29 |
| | | 399960 | | | 90959 | | | 144995 | 30 |
| | | 3768059 | | | 4581 | | | 254770 | 31 |
| | | 472004 | | | 219946 | | | 1178277 | 32 |
| | | 112414 | | | 0 | | | 0 | 33 |
| | | 22748204 | | | 5113377 | | | 5439710 | 34 |
| | | 0.0995 | | | 0.0773 | | | 0.0630 | 35 |
| Coal | Oil | | Gas | | | GAS | | | 36 |
| Tons | Barrels | | MCF | | | MCF | | | 37 |
| 131541 | 5815 | 0 | 826814 | 0 | 0 | 891124 | 0 | 0 | 38 |
| 8937 | 138778 | 0 | 1027 | 0 | 0 | 1027 | 0 | 0 | 39 |
| 0.000 | 79.177 | 0.000 | 4.810 | 0.000 | 0.000 | 3.826 | 0.000 | 0.000 | 40 |
| 85.711 | 75.124 | 0.000 | 4.810 | 0.000 | 0.000 | 3.826 | 0.000 | 0.000 | 41 |
| 4.771 | 12.889 | 0.000 | 4.500 | 0.000 | 0.000 | 3.650 | 0.000 | 0.000 | 42 |
| 0.051 | 0.000 | 0.000 | 0.060 | 0.000 | 0.000 | 0.039 | 0.000 | 0.000 | 43 |
| 10479.000 | 0.000 | 0.000 | 12829.000 | 0.000 | 0.000 | 10591.000 | 0.000 | 0.000 | 44 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

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

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

| Line No. | Item (a) | Plant Name: *Langley Gulch* (b) | | | Plant Name: (c) | | |
|---|---|---|---|---|---|---|---|
| 1 | Kind of Plant (Internal Comb, Gas Turb, Nuclear | Gas Turbine | | | | | |
| 2 | Type of Constr (Conventional, Outdoor, Boiler, etc) | Conventional | | | | | |
| 3 | Year Originally Constructed | 2012 | | | | | |
| 4 | Year Last Unit was Installed | 2012 | | | | | |
| 5 | Total Installed Cap (Max Gen Name Plate Ratings-MW) | 318.45 | | | 0.00 | | |
| 6 | Net Peak Demand on Plant - MW (60 minutes) | 310 | | | 0 | | |
| 7 | Plant Hours Connected to Load | 5079 | | | 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 | 23 | | | 0 | | |
| 12 | Net Generation, Exclusive of Plant Use - KWh | 1350692000 | | | 0 | | |
| 13 | Cost of Plant: Land and Land Rights | 2287261 | | | 0 | | |
| 14 | Structures and Improvements | 135401444 | | | 0 | | |
| 15 | Equipment Costs | 236782901 | | | 0 | | |
| 16 | Asset Retirement Costs | 0 | | | 0 | | |
| 17 | Total Cost | 374471606 | | | 0 | | |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 1175.9196 | | | 0 | | |
| 19 | Production Expenses: Oper, Supv, & Engr | 500902 | | | 0 | | |
| 20 | Fuel | 30544960 | | | 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 | 3466431 | | | 0 | | |
| 26 | Misc Steam (or Nuclear) Power Expenses | 451791 | | | 0 | | |
| 27 | Rents | 0 | | | 0 | | |
| 28 | Allowances | 0 | | | 0 | | |
| 29 | Maintenance Supervision and Engineering | 0 | | | 0 | | |
| 30 | Maintenance of Structures | 99137 | | | 0 | | |
| 31 | Maintenance of Boiler (or reactor) Plant | 290325 | | | 0 | | |
| 32 | Maintenance of Electric Plant | 827886 | | | 0 | | |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | | | 0 | | |
| 34 | Total Production Expenses | 36181432 | | | 0 | | |
| 35 | Expenses per Net KWh | 0.0268 | | | 0.0000 | | |
| 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 | 9101138 | 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 | 3.356 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 3.356 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 3.310 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 43 | Average Cost of Fuel Burned per KWh Net Gen | 0.023 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 44 | Average BTU per KWh Net Generation | 6920.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

***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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>(a) | FERC Licensed Project No. 2736<br>Plant Name: American Falls<br>(b) | FERC Licensed Project No. 1975<br>Plant Name: Bliss<br>(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) | 106 | 52 |
| 7 | Plant Hours Connect to Load | 7,357 | 8,693 |
| 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 | 482,999,000 | 343,369,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 875,318 | 768,366 |
| 15 | Structures and Improvements | 11,970,406 | 1,739,818 |
| 16 | Reservoirs, Dams, and Waterways | 4,293,075 | 9,254,107 |
| 17 | Equipment Costs | 32,334,221 | 9,989,731 |
| 18 | Roads, Railroads, and Bridges | 839,276 | 486,477 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 50,312,296 | 22,238,499 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 545.0953 | 296.5133 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 226,549 | 686,656 |
| 24 | Water for Power | 1,648,928 | 492,979 |
| 25 | Hydraulic Expenses | 149,495 | 890,584 |
| 26 | Electric Expenses | 54,746 | 74,476 |
| 27 | Misc Hydraulic Power Generation Expenses | 428,735 | 673,894 |
| 28 | Rents | 183 | 4,699 |
| 29 | Maintenance Supervision and Engineering | 6,825 | 3,787 |
| 30 | Maintenance of Structures | 175,185 | 42,259 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 92,288 | 3,576 |
| 32 | Maintenance of Electric Plant | 104,761 | 7,978 |
| 33 | Maintenance of Misc Hydraulic Plant | 85,690 | 200,241 |
| 34 | Total Production Expenses (total 23 thru 33) | 2,973,385 | 3,081,129 |
| 35 | Expenses per net KWh | 0.0062 | 0.0090 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>Plant Name: Brownlee<br>(d) | FERC Licensed Project No. 2848<br>Plant Name: Cascade<br>(e) | FERC Licensed Project No. 1971<br>Plant Name: Oxbow<br>(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 |
| 602 | 13 | 211 | 6 |
| 8,736 | 8,640 | 8,735 | 7 |
| | | | 8 |
| 747 | 15 | 221 | 9 |
| 220 | 1 | 202 | 10 |
| 8 | 2 | 7 | 11 |
| 2,394,269,000 | 47,655,000 | 1,195,770,000 | 12 |
| | | | 13 |
| 18,253,689 | 82,142 | 1,212,767 | 14 |
| 37,211,286 | 7,328,252 | 13,188,581 | 15 |
| 67,618,611 | 3,145,630 | 31,343,667 | 16 |
| 100,361,290 | 13,394,610 | 21,110,964 | 17 |
| 518,444 | 122,668 | 585,876 | 18 |
| 0 | 0 | 0 | 19 |
| 223,963,320 | 24,073,302 | 67,441,855 | 20 |
| 382.5817 | 1,938.2691 | 354.9571 | 21 |
| | | | 22 |
| 838,421 | 225,980 | 455,424 | 23 |
| 307,620 | 132,783 | 164,549 | 24 |
| 1,124,545 | 416,853 | 624,457 | 25 |
| 396,973 | 133,916 | 243,966 | 26 |
| 1,162,291 | 406,405 | 647,621 | 27 |
| 116,098 | 72 | 19,035 | 28 |
| 17,638 | 2,964 | 7,542 | 29 |
| 96,195 | 17,624 | 146,109 | 30 |
| 179,495 | 0 | 12,925 | 31 |
| 359,442 | 82,836 | 115,037 | 32 |
| 569,018 | 101,873 | 238,025 | 33 |
| 5,167,736 | 1,521,306 | 2,674,690 | 34 |
| 0.0022 | 0.0319 | 0.0022 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>Plant Name: Hells Canyon (b) | FERC Licensed Project No. 2726<br>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) | 435 | 23 |
| 7 | Plant Hours Connect to Load | 8,736 | 8,736 |
| 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 | 3 | 1 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 2,514,407,000 | 129,521,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 1,880,381 | 205,376 |
| 15 | Structures and Improvements | 2,869,602 | 3,964,636 |
| 16 | Reservoirs, Dams, and Waterways | 53,033,657 | 6,302,917 |
| 17 | Equipment Costs | 20,175,733 | 15,429,822 |
| 18 | Roads, Railroads, and Bridges | 922,781 | 1,507,442 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 78,882,154 | 27,410,193 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 201.4870 | 1,259.0810 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 360,562 | 180,900 |
| 24 | Water for Power | 155,096 | 737,587 |
| 25 | Hydraulic Expenses | 563,083 | 207,199 |
| 26 | Electric Expenses | 208,908 | 51,891 |
| 27 | Misc Hydraulic Power Generation Expenses | 651,717 | 272,684 |
| 28 | Rents | 31,663 | 0 |
| 29 | Maintenance Supervision and Engineering | 13,567 | 4,351 |
| 30 | Maintenance of Structures | 27,903 | 44,586 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 110,508 | 85,771 |
| 32 | Maintenance of Electric Plant | 138,470 | 86,142 |
| 33 | Maintenance of Misc Hydraulic Plant | 649,298 | 75,452 |
| 34 | Total Production Expenses (total 23 thru 33) | 2,910,775 | 1,746,563 |
| 35 | Expenses per net KWh | 0.0012 | 0.0135 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>Plant Name: C J Strike<br>(d) | FERC Licensed Project No. 503<br>Plant Name: Swan Falls<br>(e) | FERC Licensed Project No. 18<br>Plant Name: Twin Falls<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Run-of-River | Run-of-River | Run-of-River | 1 |
| Outdoor | Conventional | Conventional | 2 |
| 1952 | 1910 | 1935 | 3 |
| 1952 | 1994 | 1995 | 4 |
| 82.80 | 25.00 | 52.74 | 5 |
| 92 | 24 | 51 | 6 |
| 8,722 | 8,727 | 7,529 | 7 |
| | | | 8 |
| 91 | 24 | 53 | 9 |
| 84 | 14 | 50 | 10 |
| 4 | 4 | 3 | 11 |
| 550,191,000 | 130,191,000 | 214,318,000 | 12 |
| | | | 13 |
| 5,725,987 | 263,249 | 255,499 | 14 |
| 9,943,913 | 27,491,203 | 11,139,603 | 15 |
| 11,225,224 | 15,989,465 | 9,072,436 | 16 |
| 14,229,579 | 31,599,687 | 22,177,128 | 17 |
| 1,602,868 | 835,946 | 1,917,603 | 18 |
| 0 | 0 | 0 | 19 |
| 42,727,571 | 76,179,550 | 44,562,269 | 20 |
| 516.0335 | 3,047.1820 | 844.9425 | 21 |
| | | | 22 |
| 878,408 | 425,670 | 327,800 | 23 |
| 431,627 | 221,330 | 123,488 | 24 |
| 1,278,795 | 604,587 | 196,332 | 25 |
| 76,520 | 56,260 | 79,136 | 26 |
| 1,160,238 | 683,537 | 387,962 | 27 |
| 50,456 | 7,864 | 3,538 | 28 |
| 9,546 | 4,675 | 4,436 | 29 |
| 127,633 | 76,681 | 76,583 | 30 |
| 218,513 | 17,026 | 8,723 | 31 |
| 196,413 | 96,159 | 112,228 | 32 |
| 97,940 | 123,809 | 100,066 | 33 |
| 4,526,089 | 2,317,598 | 1,420,292 | 34 |
| 0.0082 | 0.0178 | 0.0066 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>Plant Name: Upper Salmon (b) | FERC Licensed Project No. 2778<br>Plant Name: Shoshone Falls (c) |
|---|---|---|---|
| | | | |
| | | | |
| 1 | Kind of Plant (Run-of-River or Storage) | Run-of-River | Run-of-River |
| 2 | Plant Construction type (Conventional or Outdoor) | Outdoor | Conventional |
| 3 | Year Originally Constructed | 1937 | 1907 |
| 4 | Year Last Unit was Installed | 1947 | 1921 |
| 5 | Total installed cap (Gen name plate Rating in MW) | 34.50 | 12.50 |
| 6 | Net Peak Demand on Plant-Megawatts (60 minutes) | 35 | 13 |
| 7 | Plant Hours Connect to Load | 8,736 | 8,710 |
| 8 | Net Plant Capability (in megawatts) | | |
| 9 | (a) Under Most Favorable Oper Conditions | 39 | 14 |
| 10 | (b) Under the Most Adverse Oper Conditions | 32 | 11 |
| 11 | Average Number of Employees | 3 | 3 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 241,735,000 | 93,460,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 202,399 | 313,328 |
| 15 | Structures and Improvements | 2,729,832 | 1,593,707 |
| 16 | Reservoirs, Dams, and Waterways | 6,181,301 | 10,013,741 |
| 17 | Equipment Costs | 9,023,589 | 4,832,072 |
| 18 | Roads, Railroads, and Bridges | 29,359 | 51,383 |
| 19 | Asset Retirement Costs | 0 | 0 |
| 20 | TOTAL cost (Total of 14 thru 19) | 18,166,480 | 16,804,231 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 526.5646 | 1,344.3385 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 225,097 | 177,233 |
| 24 | Water for Power | 122,390 | 86,622 |
| 25 | Hydraulic Expenses | 351,345 | 131,457 |
| 26 | Electric Expenses | 141,252 | 36,122 |
| 27 | Misc Hydraulic Power Generation Expenses | 365,584 | 342,081 |
| 28 | Rents | 0 | 225 |
| 29 | Maintenance Supervision and Engineering | 6,801 | 1,937 |
| 30 | Maintenance of Structures | 95,487 | 27,853 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 32,244 | -4,025 |
| 32 | Maintenance of Electric Plant | 206,321 | 28,062 |
| 33 | Maintenance of Misc Hydraulic Plant | 122,225 | 78,070 |
| 34 | Total Production Expenses (total 23 thru 33) | 1,668,746 | 905,637 |
| 35 | Expenses per net KWh | 0.0069 | 0.0097 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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<br>Plant Name: Common Facilities<br>(d) | FERC Licensed Project No. 2061<br>Plant Name: Lower Salmon<br>(e) | FERC Licensed Project No. 2899<br>Plant Name: Milner<br>(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 | 63 | 59 | 6 |
| 0 | 8,709 | 6,748 | 7 |
| | | | 8 |
| 0 | 64 | 61 | 9 |
| 0 | 60 | 1 | 10 |
| 0 | 6 | 2 | 11 |
| 0 | 308,425,000 | 237,491,000 | 12 |
| | | | 13 |
| 114,368 | 424,428 | 138,100 | 14 |
| 50,375,798 | 3,445,687 | 10,696,551 | 15 |
| 13,556,785 | 7,881,414 | 17,767,002 | 16 |
| 2,369,851 | 17,758,441 | 29,255,240 | 17 |
| 146,581 | 88,693 | 501,877 | 18 |
| 0 | 0 | 0 | 19 |
| 66,563,383 | 29,598,663 | 58,358,770 | 20 |
| 0.0000 | 493.3111 | 981.6446 | 21 |
| | | | 22 |
| 0 | 383,936 | 221,158 | 23 |
| 0 | 184,325 | 1,004,611 | 24 |
| 7,603,075 | 584,176 | 159,386 | 25 |
| 0 | 166,112 | 53,898 | 26 |
| 182 | 590,617 | 336,528 | 27 |
| 0 | 4,234 | 3,720 | 28 |
| 0 | 5,234 | 3,269 | 29 |
| 0 | 87,396 | 48,344 | 30 |
| 0 | 10,667 | 14,068 | 31 |
| 0 | 173,036 | 101,148 | 32 |
| 163,605 | 80,082 | 55,750 | 33 |
| 7,766,862 | 2,269,815 | 2,001,880 | 34 |
| 0.0000 | 0.0074 | 0.0084 | 35 |

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

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

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

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

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

Upstream storage in Brownlee Reservoir

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

Upstream storage in Brownlee Reservoir

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

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

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

| Line No. | Name of Plant<br>(a) | Year Orig. Const.<br>(b) | Installed Capacity Name Plate Rating (In MW)<br>(c) | Net Peak Demand MW (60 min.)<br>(d) | Net Generation Excluding Plant Use<br>(e) | Cost of Plant<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Hydro: | | | | | |
| 2 | Clear Lakes | 1937 | 2.50 | 3.9 | 16,514 | 3,544,451 |
| 3 | Thousand Springs | 1912 | 8.80 | | -256 | 10,106,248 |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | Internal Combustion: | | | | | |
| 7 | Salmon Diesel | 1967 | 5.00 | 3.7 | 18 | 909,259 |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 |
| 1,417,780 | 314,282 | | 120,895 | | | 2 |
| 1,148,437 | 236,307 | | 117,575 | | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| 181,852 | | | | Diesel | | 7 |
| | | | | | | 8 |
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***Schedule Page: 410 Line No.: 7 Column: a***

Salmon units are classified as standby.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | 62.35 | | 1 |
| 2 | Boardman | Slatt | 500.00 | 500.00 | S Tower | 1.79 | | 1 |
| 3 | Summer lake | Hemingway | 500.00 | 500.00 | S Tower | 0.08 | | 1 |
| 4 | Hemingway | Midpoint | 500.00 | 500.00 | S Tower | 0.15 | | 1 |
| 5 | Summer Lake | Hemingway | 500.00 | 500.00 | S Tower | 53.08 | | 1 |
| 6 | Hemingway | Midpoint | 500.00 | 500.00 | S Tower | 47.76 | | 1 |
| 7 | | | | | | | | |
| 8 | Jim Bridger | Goshen | 345.00 | 345.00 | S Tower | 66.15 | | 1 |
| 9 | State Line | Midpoint | 345.00 | 345.00 | S Tower | 76.06 | | 2 |
| 10 | Kinport | Borah | 345.00 | 345.00 | S Tower | 19.81 | | 1 |
| 11 | Jim Bridger | Populus | 345.00 | 345.00 | S Tower | 60.93 | | 1 |
| 12 | Populus | Kinport | 345.00 | 345.00 | S Tower | 7.42 | | 1 |
| 13 | Jim Bridger | Populus | 345.00 | 345.00 | S Tower | 61.12 | | 1 |
| 14 | Populus | Borah | 345.00 | 345.00 | S Tower | 9.05 | | 1 |
| 15 | Goshen | Kinport | 345.00 | 345.00 | S Tower | 7.48 | | 1 |
| 16 | Midpoint | Borah #1 | 345.00 | 345.00 | H Wood | 51.07 | | 1 |
| 17 | Midpoint | Borah #2 | 345.00 | 345.00 | H Wood | 49.98 | | 2 |
| 18 | Adelaide Tap | Adelaide | 345.00 | 345.00 | H Wood | 1.72 | | 2 |
| 19 | | | | | | | | |
| 20 | Quartz | LaGrande | 230.00 | 230.00 | H Wood | 45.97 | | 1 |
| 21 | Midpoint | Hunt | 230.00 | 230.00 | S Tower | 0.70 | | 2 |
| 22 | Brady | Antelope | 230.00 | 230.00 | H Wood | 56.38 | | 1 |
| 23 | Brady | Treasureton | 230.00 | 230.00 | H Wood | 0.08 | | 1 |
| 24 | Brady #1 & #2 | Kinport | 230.00 | 230.00 | S Tower | 17.94 | | 2 |
| 25 | Brownlee | Ontario | 230.00 | 230.00 | S Tower | 72.67 | | 1 |
| 26 | Mora | Bowmont | 138.00 | 230.00 | S P Wood | 9.98 | | 1 |
| 27 | Mora | Bowmont | 138.00 | 230.00 | H Wood | 8.75 | | 1 |
| 28 | Caldwell 710 | Locust | 230.00 | 230.00 | SP Steel | 18.49 | | 1 |
| 29 | Boise Bench | Caldwell | 230.00 | 230.00 | S Tower | 7.70 | | 1 |
| 30 | Boise Bench | Caldwell | 230.00 | 230.00 | H Wood | 33.49 | | 1 |
| 31 | Boise Bench | Cloverdale | 230.00 | 230.00 | S Tower | 15.91 | | 2 |
| 32 | Boardman | Dalreed Sub | 230.00 | 230.00 | H Wood | 1.67 | | 1 |
| 33 | Brownlee 714 | Oxbow | 230.00 | 230.00 | SP Steel | 11.04 | | 2 |
| 34 | Caldwell | Ontario | 230.00 | 230.00 | H Wood | 30.06 | | 1 |
| 35 | Caldwell | Ontario | 230.00 | 230.00 | S Tower | 3.14 | | 1 |
| 36 | | | | | TOTAL | 4,769.89 | 11.02 | 203 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1272 ACSR | 256,381 | 15,976,932 | 16,233,313 | | | | | 1 |
| 2X1780 ACSR | | 446,708 | 446,708 | | | | | 2 |
| 1272 ACSR | | | | | | | | 3 |
| 1272 ACSR | | | | | | | | 4 |
| 3X1272 ACSR | | 18,831,753 | 18,831,753 | | | | | 5 |
| 3X1272 ACSR | | 17,078,061 | 17,078,061 | | | | | 6 |
| | | | | | | | | 7 |
| 1272 ACSR | 483,309 | 5,302,417 | 5,785,726 | | | | | 8 |
| 795 ACSR | 571,979 | 11,223,451 | 11,795,430 | | | | | 9 |
| 1272 ACSR | 344,220 | 4,397,073 | 4,741,293 | | | | | 10 |
| 1272 ACSR | | 9,530,707 | 9,530,707 | | | | | 11 |
| 1272 ACSR | | | | | | | | 12 |
| 1272 ACSR | | 9,253,816 | 9,253,816 | | | | | 13 |
| 1272 ACSR | | | | | | | | 14 |
| 2X1272 ACSR | | 583,947 | 583,947 | | | | | 15 |
| 715.5 ACSR | 283,143 | 8,551,189 | 8,834,332 | | | | | 16 |
| 715.5 ACSR | 64,851 | 16,447,655 | 16,512,506 | | | | | 17 |
| 715.5 ACSR | 51,448 | 224,249 | 275,697 | | | | | 18 |
| | | | | | | | | 19 |
| 795 ACSR | 62,218 | 7,010,643 | 7,072,861 | | | | | 20 |
| 715.5 ACSR | 9,145 | 998,452 | 1,007,597 | | | | | 21 |
| 1272 ACSR | 108,301 | 3,399,123 | 3,507,424 | | | | | 22 |
| 795 ACSR | | 6,186 | 6,186 | | | | | 23 |
| 715.5 ACSR | 18,829 | 1,091,655 | 1,110,484 | | | | | 24 |
| 2X954 ACSR | 1,676,838 | 20,541,790 | 22,218,628 | | | | | 25 |
| 715.5 ACSR | 413,793 | 2,336,849 | 2,750,642 | | | | | 26 |
| 715.5 ACSR | | | | | | | | 27 |
| 1590 ACSR | 2,378,436 | 8,775,086 | 11,153,522 | | | | | 28 |
| 1272 ACSR | 1,748,214 | 7,722,452 | 9,470,666 | | | | | 29 |
| 715.5 ACSR | | | | | | | | 30 |
| 1272 ACSR | 3,062,812 | 6,653,374 | 9,716,186 | | | | | 31 |
| 795 AAC | | 89,089 | 89,089 | | | | | 32 |
| 954 ACSR | 34,174 | 16,026,470 | 16,060,644 | | | | | 33 |
| 2X954 ACSR | 236,152 | 9,384,090 | 9,620,242 | | | | | 34 |
| 1272 ACSR | | | | | | | | 35 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Bennett Mtn PP | Rattlesnake TS | 230.00 | 230.00 | SP Steel | 4.43 | | 1 |
| 2 | Borah | Hunt | 230.00 | 230.00 | H Steel | 68.12 | | 1 |
| 3 | Danskin | Hubbard | 230.00 | 230.00 | H Steel | 36.25 | | 1 |
| 4 | Danskin | Hubbard | 230.00 | 230.00 | SP Steel | 1.84 | | 1 |
| 5 | Danskin | Hubbard | 230.00 | 230.00 | SP Steel | 1.30 | | 2 |
| 6 | Danskin | Bennett Mtn | 230.00 | 230.00 | SP Steel | 5.39 | | 1 |
| 7 | Hemingway | Bowmont | 230.00 | 230.00 | SP Steel | 12.94 | | 1 |
| 8 | Langley Gulch | Galloway Rd | 138.00 | 230.00 | SP Steel | 14.19 | | 1 |
| 9 | Galloway Rd | Willis Tap | 138.00 | 230.00 | SP Steel | 2.09 | | 1 |
| 10 | Walla Walla | Hurricane | 230.00 | 230.00 | H Wood | 31.66 | | 1 |
| 11 | Boise Bench | Midpoint #1 | 230.00 | 230.00 | S Tower | 0.68 | | 1 |
| 12 | Boise Bench | Midpoint #1 | 230.00 | 230.00 | H Wood | 108.68 | | 1 |
| 13 | Brownlee | Quartz Jct | 230.00 | 230.00 | S Tower | 1.51 | | 1 |
| 14 | Brownlee | Quartz Jct | 230.00 | 230.00 | H Wood | 41.30 | | 1 |
| 15 | Brownlee | Boise Bench #1 & #2 | 230.00 | 230.00 | S Tower | 99.76 | | 2 |
| 16 | Oxbow | Brownlee | 230.00 | 230.00 | S Tower | 10.40 | | 2 |
| 17 | Boise Bench | Midpoint #2 | 230.00 | 230.00 | S Tower | 3.49 | | 1 |
| 18 | Boise Bench | Midpoint #2 | 230.00 | 230.00 | H Wood | 102.17 | | 1 |
| 19 | Oxbow | Pallette Jct | 230.00 | 230.00 | S Tower | 20.11 | | 2 |
| 20 | Pallette Jct | Imnaha | 230.00 | 230.00 | H Wood | 24.43 | | 2 |
| 21 | Hells Canyon | Palette Jct | 230.00 | 230.00 | S Tower | 9.05 | | 2 |
| 22 | Brownlee | Boise Bench | 230.00 | 230.00 | S Tower | 102.08 | | 2 |
| 23 | Boise Bench | Midpoint #3 | 230.00 | 230.00 | H Wood | 106.29 | | 1 |
| 24 | Palette Jct | Enterprise | 230.00 | 230.00 | H Wood | 29.60 | | 1 |
| 25 | Borah | Brady #2 | 230.00 | 230.00 | S Tower | 0.42 | | 1 |
| 26 | Borah | Brady #2 | 230.00 | 230.00 | H Wood | 3.52 | | 1 |
| 27 | Borah | Brady #1 | 230.00 | 230.00 | H Wood | 3.84 | | 1 |
| 28 | | | | | | | | |
| 29 | Goshen | State Line | 161.00 | 161.00 | H Wood | 40.89 | | 1 |
| 30 | Don | Goshen | 161.00 | 161.00 | S Tower | 2.37 | | 2 |
| 31 | Don | Goshen | 161.00 | 161.00 | H Wood | 48.42 | | 2 |
| 32 | Antelope | Goshen | 161.00 | 161.00 | H Wood | 5.67 | | 1 |
| 33 | Goshen | State Line | 161.00 | 161.00 | H Wood | 10.93 | | 1 |
| 34 | Goshen | State Line | 161.00 | 161.00 | H Wood | 7.84 | | 1 |
| 35 | | | | | | | | |
| 36 | | | | | TOTAL | 4,769.89 | 11.02 | 203 |

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1272 ACSR | 81,701 | 1,666,354 | 1,748,055 | | | | | 1 |
| 1590 ACSR | 624,917 | 22,467,321 | 23,092,238 | | | | | 2 |
| 1590 ACSR | | 15,210,561 | 15,210,561 | | | | | 3 |
| 1590 ACSR | | | | | | | | 4 |
| 1590 ACSR | | | | | | | | 5 |
| 1590 ACSR | | 3,528,033 | 3,528,033 | | | | | 6 |
| 1590 ACSR | 1,854,996 | 9,277,980 | 11,132,976 | | | | | 7 |
| 1590 ACSR | 948,166 | 9,067,609 | 10,015,775 | | | | | 8 |
| 1272 ACSR | | | | | | | | 9 |
| 1272 ACSR | | 6,264,553 | 6,264,553 | | | | | 10 |
| 715.5 ACSR | 385,287 | 11,912,816 | 12,298,103 | | | | | 11 |
| 715.5 ACSR | | | | | | | | 12 |
| 795 ACSR | 53,068 | 4,794,561 | 4,847,629 | | | | | 13 |
| 795 ACSR | | | | | | | | 14 |
| VARIOUS | 289,934 | 8,966,987 | 9,256,921 | | | | | 15 |
| 1272 ACSR | 14,810 | 1,273,328 | 1,288,138 | | | | | 16 |
| 715.5 ACSR | 227,825 | 18,013,024 | 18,240,849 | | | | | 17 |
| VARIOUS | | | | | | | | 18 |
| 1272 ACSR | 87,468 | 3,906,027 | 3,993,495 | | | | | 19 |
| 1272 ACSR | 171,081 | 2,054,803 | 2,225,884 | | | | | 20 |
| 1272 ACSR | 44,687 | 1,252,130 | 1,296,817 | | | | | 21 |
| 954 ACSR | 184,817 | 6,257,154 | 6,441,971 | | | | | 22 |
| 715.5 ACSR | 247,857 | 8,037,331 | 8,285,188 | | | | | 23 |
| 1272 ACSR | 84,014 | 1,903,192 | 1,987,206 | | | | | 24 |
| 1272 ACSR | 3,068 | 531,106 | 534,174 | | | | | 25 |
| 715.5 ACSR | | | | | | | | 26 |
| 1272 ACSR | 7,248 | 421,273 | 428,521 | | | | | 27 |
| | | | | | | | | 28 |
| 250 COPPER | 375,576 | 3,208,829 | 3,584,405 | | | | | 29 |
| 715.5 ACSR | 88,204 | 2,544,302 | 2,632,506 | | | | | 30 |
| 397.5 ACSR | | | | | | | | 31 |
| 397.5 ACSR | | 784,659 | 784,659 | | | | | 32 |
| 250 COPPER | 118,058 | 1,202,360 | 1,320,418 | | | | | 33 |
| 250 COPPER | 75,951 | 190,295 | 266,246 | | | | | 34 |
| | | | | | | | | 35 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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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 | American Falls Power Plant | Adelaide | 138.00 | 138.00 | H Wood | 14.07 | | 2 |
| 2 | American Falls Power Plant | Adelaide | 138.00 | 138.00 | S P Wood | 0.12 | | 2 |
| 3 | Minidoka Loop | Adelaide | 138.00 | 138.00 | S Tower | 1.14 | | 2 |
| 4 | Nampa | Caldwell | 138.00 | 138.00 | S P Wood | 9.59 | | 2 |
| 5 | Upper Salmon | Mountain Home Jct | 138.00 | 138.00 | H Wood | 54.36 | | 1 |
| 6 | Upper Salmon | Cliff | 138.00 | 138.00 | H Wood | 30.81 | | 1 |
| 7 | Eastgate | Russet | 138.00 | 138.00 | S P Wood | 2.06 | | 1 |
| 8 | Brady | Fremont | 138.00 | 138.00 | S Tower | 1.00 | | 2 |
| 9 | Brady | Fremont | 138.00 | 138.00 | H Wood | 24.38 | | 2 |
| 10 | Brady | Fremont | 138.00 | 138.00 | S P Wood | 24.33 | | 2 |
| 11 | King | Lower Malad | 138.00 | 138.00 | H Wood | 84.73 | | 2 |
| 12 | Emmett Jct | Payette | 138.00 | 138.00 | H Wood | 66.46 | | 2 |
| 13 | Mountain Home AFB Tap | | 138.00 | 138.00 | H Wood | 6.20 | | 1 |
| 14 | Ontario | Quartz | 138.00 | 138.00 | H Wood | 73.20 | | 1 |
| 15 | King | American Falls PP | 138.00 | 138.00 | S Tower | 0.93 | | 2 |
| 16 | King | American Falls PP | 138.00 | 138.00 | H Wood | 142.16 | | 1 |
| 17 | King | American Falls PP | 138.00 | 138.00 | S P Wood | 3.71 | | 1 |
| 18 | Duffin | Clawson | 138.00 | 138.00 | H Wood | 6.19 | | 1 |
| 19 | American Falls | Brady Tie | 138.00 | 138.00 | H Wood | 0.33 | | 1 |
| 20 | Upper Salmon A-B | King | 138.00 | 138.00 | H Wood | 5.66 | | 1 |
| 21 | Upper Salmon B | Wells | 138.00 | 138.00 | H Wood | 125.54 | | 1 |
| 22 | King | Wood River | 138.00 | 138.00 | H Wood | 64.13 | | 1 |
| 23 | Toponis | Pocket | 138.00 | 138.00 | S P Wood | 9.80 | | 1 |
| 24 | Boise Bench | Grove | 138.00 | 138.00 | S P Wood | 10.37 | | 2 |
| 25 | Quartz | John Day | 138.00 | 138.00 | H Wood | 67.13 | | 1 |
| 26 | Sinker Creek Tap | | 138.00 | 138.00 | H Wood | 2.79 | | 1 |
| 27 | Mora | Cloverdale | 138.00 | 138.00 | H Wood | 2.51 | | 1 |
| 28 | Mora | Cloverdale | 138.00 | 138.00 | S P Wood | 22.28 | | 1 |
| 29 | Mora | Cloverdale | 138.00 | 138.00 | S P Steel | 0.96 | | 2 |
| 30 | Stoddard Jct | Stoddard Sub | 138.00 | 138.00 | S P Steel | 3.80 | | 1 |
| 31 | Fossil Gulch Tap | | 138.00 | 138.00 | H Wood | 1.95 | | 1 |
| 32 | Wood River | Midpoint | 138.00 | 138.00 | H Wood | 53.08 | | 2 |
| 33 | Wood River | Midpoint | 138.00 | 138.00 | S P Wood | 16.69 | | 2 |
| 34 | Oxbow | McCall | 138.00 | 138.00 | H Wood | 37.15 | | 1 |
| 35 | Oxbow | McCall | 138.00 | 138.00 | S P Wood | 2.32 | | 1 |
| 36 | | | | | TOTAL | 4,769.89 | 11.02 | 203 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 250 COPPER | 26,507 | 415,412 | 441,919 | | | | | 1 |
| 250 COPPER | | | | | | | | 2 |
| 715.5 ACSR | 21,327 | 249,232 | 270,559 | | | | | 3 |
| 795 AAC | 719,463 | 3,301,089 | 4,020,552 | | | | | 4 |
| 795 ACSR | 78,078 | 5,065,961 | 5,144,039 | | | | | 5 |
| 795 ACSR | 43,568 | 3,066,311 | 3,109,879 | | | | | 6 |
| 795 AAC | 270,823 | 561,561 | 832,384 | | | | | 7 |
| VARIOUS | 564,932 | 4,493,392 | 5,058,324 | | | | | 8 |
| VARIOUS | | | | | | | | 9 |
| VARIOUS | | | | | | | | 10 |
| VARIOUS | 76,823 | 3,735,604 | 3,812,427 | | | | | 11 |
| VARIOUS | 55,521 | 3,233,475 | 3,288,996 | | | | | 12 |
| 397.5 ACSR | 5,086 | 83,131 | 88,217 | | | | | 13 |
| VARIOUS | 34,428 | 6,718,464 | 6,752,892 | | | | | 14 |
| 715.5 ACSR | 216,919 | 10,418,043 | 10,634,962 | | | | | 15 |
| 715.5 ACSR | | | | | | | | 16 |
| 715.5 ACSR | | | | | | | | 17 |
| 4\0 | 4,191 | 467,909 | 472,100 | | | | | 18 |
| 954 ACSR | | 96,921 | 96,921 | | | | | 19 |
| 250 COPPER | 2,741 | 753,925 | 756,666 | | | | | 20 |
| VARIOUS | 28,490 | 3,541,534 | 3,570,024 | | | | | 21 |
| VARIOUS | 173,683 | 26,237,049 | 26,410,732 | | | | | 22 |
| 397.5 ACSR | | | | | | | | 23 |
| VARIOUS | 225,602 | 1,648,079 | 1,873,681 | | | | | 24 |
| 397.5 ACSR | 96,582 | 2,554,374 | 2,650,956 | | | | | 25 |
| VARIOUS | 11,083 | 133,347 | 144,430 | | | | | 26 |
| 715.5 ACSR | 3,123,380 | 8,875,271 | 11,998,651 | | | | | 27 |
| VARIOUS | | | | | | | | 28 |
| 795AAC | | | | | | | | 29 |
| 1272 ACSR | | | | | | | | 30 |
| 250 COPPER | 450 | 187,848 | 188,298 | | | | | 31 |
| 397.5 ACSR | 349,712 | 7,122,899 | 7,472,611 | | | | | 32 |
| 397.5 ACSR | | | | | | | | 33 |
| 397.5 ACSR | 141,534 | 2,745,214 | 2,886,748 | | | | | 34 |
| 397.5 ACSR | | | | | | | | 35 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 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 | 04/18/2018 | End of 2017/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 | Lowell Jct | Nampa | 138.00 | 138.00 | S P Wood | 7.50 | | 2 |
| 2 | Hunt | Milner | 138.00 | 138.00 | S P Wood | 19.42 | | 1 |
| 3 | Strike | Bruneau Bridge | 138.00 | 138.00 | H Wood | 13.49 | | 1 |
| 4 | American Falls | Kramer Sub | 138.00 | 138.00 | S P Wood | 18.46 | | 2 |
| 5 | Pingree | Haven | 138.00 | 138.00 | S P Wood | 11.72 | | 1 |
| 6 | Midpoint | Twin Falls | 138.00 | 138.00 | S P Wood | 25.20 | | 2 |
| 7 | Twin Falls | Russett | 138.00 | 138.00 | S P Wood | 1.71 | | 1 |
| 8 | Blackfoot | Aiken | 46.00 | 138.00 | S P Wood | 6.22 | | 2 |
| 9 | Peterson | Tendoy | 69.00 | 138.00 | H Wood | 57.02 | | 1 |
| 10 | Eastgate Tap | Eastgate | 138.00 | 138.00 | S P Wood | 6.36 | | 1 |
| 11 | Kimberly Tap | Kimberly | 138.00 | 138.00 | S P Steel | 1.84 | | 2 |
| 12 | Boise Bench | Mora | 138.00 | 138.00 | H Wood | 13.11 | | 2 |
| 13 | Bowmont-Caldwell | Simplot Sub | 138.00 | 138.00 | S P Wood | 0.51 | | 1 |
| 14 | Gary Lane | Eagle | 138.00 | 138.00 | S P Wood | 6.66 | | 1 |
| 15 | Locust Grove | Blackcat Sub | 138.00 | 138.00 | S P Steel | 9.25 | 2.98 | 1 |
| 16 | Boise Bench | Butler | 138.00 | 138.00 | S P Wood | 0.14 | 4.02 | 1 |
| 17 | Eagle | Star | 138.00 | 138.00 | S P Wood | 6.72 | | 1 |
| 18 | Karcher Sub | Zilog Tap | 138.00 | 138.00 | S P Steel | 3.59 | | 1 |
| 19 | Cloverdale - 712 | 712 - Wye | 138.00 | 138.00 | S P Steel | 0.42 | 4.02 | 1 |
| 20 | Victory Jct | Victory | 138.00 | 138.00 | S P Steel | 1.89 | | 1 |
| 21 | Butler | Wye | 138.00 | 138.00 | S P Steel | 2.94 | | 1 |
| 22 | Horseflat | Starkey | 138.00 | 138.00 | H Wood | 33.97 | | 1 |
| 23 | Starkey | Mccall | 138.00 | 138.00 | S P Steel | 2.23 | | 2 |
| 24 | Starkey | Mccall | 138.00 | 138.00 | H Wood | 3.80 | | 1 |
| 25 | Starkey | Mccall | 138.00 | 138.00 | S P Steel | 1.50 | | 1 |
| 26 | Starkey | Mccall | 138.00 | 138.00 | S P Wood | 17.61 | | 1 |
| 27 | Chestnut | Happy Valley | 138.00 | 138.00 | S P Steel | 2.78 | | 1 |
| 28 | Garnet | Ward | | 138.00 | | | | |
| 29 | McCall | Lake Fork | 138.00 | 138.00 | S P Wood | 8.89 | | 1 |
| 30 | McCall | Lake Fork | 138.00 | 138.00 | S Steel | 2.90 | | |
| 31 | Caldwell | Willis | 138.00 | 138.00 | S P Steel | 1.30 | | 1 |
| 32 | Caldwell | Willis | 138.00 | 138.00 | S P Steel | 1.59 | | 1 |
| 33 | Caldwell | Willis | 138.00 | 138.00 | S P Wood | 0.87 | | 1 |
| 34 | Valivue Tap | | 138.00 | 138.00 | S P Steel | 0.79 | | 2 |
| 35 | Bowmont | Happy Valley | 138.00 | 138.00 | S P Steel | 8.65 | | 1 |
| 36 | | | | | TOTAL | 4,769.89 | 11.02 | 203 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 715.5 ACSR | 211,131 | 1,454,879 | 1,666,010 | | | | | 1 |
| 715.5 ACSR | 3,324 | 1,457,396 | 1,460,720 | | | | | 2 |
| 397.5 ACSR | 14,927 | 710,454 | 725,381 | | | | | 3 |
| 715.5 ACSR | 13,734 | 1,072,294 | 1,086,028 | | | | | 4 |
| 397.5 ACSR | 18,223 | 1,281,344 | 1,299,567 | | | | | 5 |
| VARIOUS | 66,286 | 3,284,778 | 3,351,064 | | | | | 6 |
| 715.5 ACSR | 16,790 | 213,033 | 229,823 | | | | | 7 |
| 715.5 ACSR | 13,616 | 529,756 | 543,372 | | | | | 8 |
| 397.5 ACSR | 395,696 | 3,504,326 | 3,900,022 | | | | | 9 |
| 715.5 ACSR | 343,955 | 2,184,427 | 2,528,382 | | | | | 10 |
| 795 ACSR | | | | | | | | 11 |
| 715.5 ACSR | 14,697 | 736,867 | 751,564 | | | | | 12 |
| 795 AAC | | 50,319 | 50,319 | | | | | 13 |
| 795 AAC | 308,141 | 2,165,954 | 2,474,095 | | | | | 14 |
| 1272 ACSR | 935,810 | 3,444,679 | 4,380,489 | | | | | 15 |
| 1272 ACSR | 34,687 | 838,605 | 873,292 | | | | | 16 |
| 715.5 ACSR | 179,817 | 2,932,783 | 3,112,600 | | | | | 17 |
| 795 AAC | 43,035 | 434,341 | 477,376 | | | | | 18 |
| 1272 ACSR | 140,412 | 2,577,075 | 2,717,487 | | | | | 19 |
| 1272 ACSR | | | | | | | | 20 |
| 795 ACSR | 134,471 | 1,405,436 | 1,539,907 | | | | | 21 |
| 715.5 ACSR | 2,473,833 | 18,903,593 | 21,377,426 | | | | | 22 |
| 715.5 ACSR | | | | | | | | 23 |
| 715.5 ACSR | | | | | | | | 24 |
| 715.5 ACSR | | | | | | | | 25 |
| 715.5 ACSR | | | | | | | | 26 |
| 1272 ACSR | 78,579 | 2,219,508 | 2,298,087 | | | | | 27 |
| | 40,580 | | 40,580 | | | | | 28 |
| 715.5 ACSR | 331,539 | 4,682,879 | 5,014,418 | | | | | 29 |
| | | | | | | | | 30 |
| 1272 ACSR | 272,231 | 2,141,218 | 2,413,449 | | | | | 31 |
| 795 ACSR | | | | | | | | 32 |
| 795 ACSR | | | | | | | | 33 |
| 795 ACSR | | 351,497 | 351,497 | | | | | 34 |
| 1272 ACSR | 691,728 | 6,045,286 | 6,737,014 | | | | | 35 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Antelope | Scoville | 138.00 | 138.00 | H Wood | 0.12 | | 1 |
| 2 | American Falls | Wheelon | 138.00 | 138.00 | H Wood | 1.05 | | 1 |
| 3 | Kinport | Don #1 | 138.00 | 138.00 | S Tower | 1.27 | | 2 |
| 4 | Donn | HOKU | 138.00 | 138.00 | S P Steel | 2.69 | | 1 |
| 5 | HOKU | Alamed | 138.00 | 138.00 | S P Steel | 0.22 | | 2 |
| 6 | HOKU | Alamed | 138.00 | 138.00 | S P Steel | 0.23 | | 2 |
| 7 | HOKU | Alamed | 138.00 | 138.00 | S P Steel | 2.85 | | 1 |
| 8 | Rockland Jct | Rockland Wind Farm | 138.00 | 138.00 | S P Steel | 5.18 | | 1 |
| 9 | King | Justice | 138.00 | 138.00 | S P Wood | 0.07 | | 1 |
| 10 | NorthView Tap | | 138.00 | 138.00 | S P Wood | 6.17 | | 1 |
| 11 | Twin Falls PP Tap | | 138.00 | 138.00 | H Wood | 0.99 | | 1 |
| 12 | American Falls PP | Amercian Falls Trans ST | 138.00 | 138.00 | S P Steel | 0.38 | | 1 |
| 13 | Lower Salmon | King Tie | 138.00 | 138.00 | H Wood | 0.11 | | 1 |
| 14 | C J Strike | Strike Jct | 138.00 | 138.00 | S Tower | 4.30 | | 2 |
| 15 | Strike Jct | Mountain Home Jct | 138.00 | 138.00 | H Wood | 23.42 | | 1 |
| 16 | Strike Jct | Bowmont | | 138.00 | H Wood | 0.05 | | 1 |
| 17 | Strike Jct | Bowmont | 138.00 | 138.00 | S Tower | 0.36 | | 1 |
| 18 | Strike Jct | Bowmont | 138.00 | 138.00 | H Wood | 67.87 | | 1 |
| 19 | Lucky Peak | Lucky Peak Jct | 138.00 | 138.00 | H Wood | 4.48 | | 2 |
| 20 | Bliss | King | 138.00 | 138.00 | H Wood | 10.47 | | 1 |
| 21 | Milner Deadend | Milner PP | 138.00 | 138.00 | S P Wood | 1.30 | | 1 |
| 22 | Swan Falls Tap | | 138.00 | 138.00 | H Wood | 0.95 | | 1 |
| 23 | | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | Hines | BPA (Harney) | 115.00 | 115.00 | H Wood | 3.35 | | 1 |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | 69 Kv Lines | | 69.00 | 69.00 | H Wood | 210.65 | | 1 |
| 30 | 69 Kv Lines | | 69.00 | 69.00 | S P Wood | 880.67 | | 1 |
| 31 | | | | | | | | |
| 32 | | | | | | | | |
| 33 | 46 Kv Lines | | 46.00 | 46.00 | S P Wood | 396.08 | | 1 |
| 34 | | | | | | | | |
| 35 | Total all lines | | | | | 4,769.89 | 11.02 | 203 |
| 36 | | | | | TOTAL | 4,769.89 | 11.02 | 203 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS (Continued)

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

| Size of Conductor and Material (i) | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 397.5 ACSR | | 71,018 | 71,018 | | | | | 1 |
| 250 COPPER | | 105,721 | 105,721 | | | | | 2 |
| 715.5 ACSR | 1,174 | 206,258 | 207,432 | | | | | 3 |
| 1272 ACSR | 190 | 4,594 | 4,784 | | | | | 4 |
| 1272 ACSR | | | | | | | | 5 |
| 795 ACSR | | | | | | | | 6 |
| 795 ACSR | | | | | | | | 7 |
| 795 ACSR | | -16,973 | -16,973 | | | | | 8 |
| 1590 ACSR | | 60,659 | 60,659 | | | | | 9 |
| 715.5 ACSR | 105,933 | 4,125,054 | 4,230,987 | | | | | 10 |
| 250 COPPER | 58 | 63,264 | 63,322 | | | | | 11 |
| 715.5 ACSR | | 176,736 | 176,736 | | | | | 12 |
| 397.5 ACSR | | 4,406 | 4,406 | | | | | 13 |
| 715.5 ACSR | 1,074 | 636,545 | 637,619 | | | | | 14 |
| 397.5 ACSR | 6,332 | 2,566,261 | 2,572,593 | | | | | 15 |
| 715.5 ACSR | 86,651 | 3,956,640 | 4,043,291 | | | | | 16 |
| 715.5 ACSR | | | | | | | | 17 |
| | | | | | | | | 18 |
| 715.5 ACSR | 7 | 285,106 | 285,113 | | | | | 19 |
| 715.5 ACSR | 5,620 | 1,387,171 | 1,392,791 | | | | | 20 |
| 715.5 ACSR | 14,968 | 183,606 | 198,574 | | | | | 21 |
| 397.5 ACSR | 17,207 | 261,512 | 278,719 | | | | | 22 |
| | | | | | | | | 23 |
| | | | | | | | | 24 |
| | | | | | | | | 25 |
| 397.5 ACSR | 1,978 | 63,404 | 65,382 | | | | | 26 |
| | | | | | | | | 27 |
| | | | | | | | | 28 |
| VARIOUS | 1,782,538 | 76,422,960 | 78,205,498 | | | | | 29 |
| VARIOUS | | | | | | | | 30 |
| | | | | | | | | 31 |
| | | | | | | | | 32 |
| VARIOUS | 194,536 | 19,387,660 | 19,582,196 | | | | | 33 |
| | | | | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 34 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 35 |
| | 33,039,407 | 616,900,179 | 649,939,586 | 7,410,221 | 1,041,358 | 4,782,018 | 13,233,597 | 36 |

| Name of Respondent | This Report is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) X An Original<br>(2) _ A Resubmission | 04/18/2018 | 2017/Q4 |

FOOTNOTE DATA

**Schedule Page: 422 Line No.: 1 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 85.4 mile line.

**Schedule Page: 422 Line No.: 2 Column: b**

This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 17.8 mile line.

**Schedule Page: 422 Line No.: 3 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

**Schedule Page: 422 Line No.: 4 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

**Schedule Page: 422 Line No.: 5 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

**Schedule Page: 422 Line No.: 6 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

**Schedule Page: 422 Line No.: 8 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 226.6 mile line.

**Schedule Page: 422 Line No.: 10 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 27.1 mile line.

**Schedule Page: 422 Line No.: 11 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

**Schedule Page: 422 Line No.: 12 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 41.2 mile line.

**Schedule Page: 422 Line No.: 13 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

**Schedule Page: 422 Line No.: 14 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 47.3 mile line.

**Schedule Page: 422 Line No.: 15 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.

**Schedule Page: 422 Line No.: 16 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 79.5 mile line.

**Schedule Page: 422 Line No.: 17 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 77.9 mile line.

**Schedule Page: 422 Line No.: 18 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 0.9 mile line.

**Schedule Page: 422 Line No.: 32 Column: b**

This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 16.7 mile line.

**Schedule Page: 422.1 Line No.: 10 Column: b**

This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.

**Schedule Page: 422.1 Line No.: 29 Column: b**

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

***Schedule Page: 422.1 Line No.: 32 Column: b***

This line is jointly owned with PacifiCorp and Idaho Power owns 21.9% of this 25.8 mile line.

***Schedule Page: 422.1 Line No.: 33 Column: b***

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

***Schedule Page: 422.1 Line No.: 34 Column: b***

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

***Schedule Page: 422.4 Line No.: 1 Column: b***

This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

***Schedule Page: 422.4 Line No.: 2 Column: b***

This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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<br>(a) | To<br>(b) | (c) | Type<br>(d) | Average Number per Miles<br>(e) | Present<br>(f) | Ultimate<br>(g) |
| 1 | No new lines for 2017 | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
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| 18 | | | | | | | |
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| 26 | | | | | | | |
| 27 | | | | | | | |
| 28 | | | | | | | |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | | | | | | | |
| 33 | | | | | | | |
| 34 | | | | | | | |
| 35 | | | | | | | |
| 36 | | | | | | | |
| 37 | | | | | | | |
| 38 | | | | | | | |
| 39 | | | | | | | |
| 40 | | | | | | | |
| 41 | | | | | | | |
| 42 | | | | | | | |
| 43 | | | | | | | |
| 44 | 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 | 04/18/2018 | End of 2017/Q4 |

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

| CONDUCTORS | | | Voltage | LINE COST | | | | | Line |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | KV (Operating) (k) | Land and Land Rights (l) | Poles, Towers and Fixtures (m) | Conductors and Devices (n) | Asset Retire. Costs (o) | Total (p) | No. |
| | | | | | | | | | 1 |
| | | | | | | | | | 2 |
| | | | | | | | | | 3 |
| | | | | | | | | | 4 |
| | | | | | | | | | 5 |
| | | | | | | | | | 6 |
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| | | | | | | | | | 39 |
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| | | | | | | | | | 41 |
| | | | | | | | | | 42 |
| | | | | | | | | | 43 |
| | | | | | | | | | 44 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Adelaide | transmission | 345.00 | 138.00 | 13.80 |
| 2 | Aiken | distribution | 46.00 | 13.00 | |
| 3 | Alameda | distribution | 138.00 | 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 | Antelope | transmission | 230.00 | 161.00 | 13.80 |
| 8 | Artesian | distribution | 46.00 | 13.00 | |
| 9 | Bannock Creek | distribution | 46.00 | 13.00 | |
| 10 | Bennett Mountain Power Plant- attended | transmission | 230.00 | 18.00 | |
| 11 | Bennett Mountain Power Plant- attended | distribution | 18.00 | 4.16 | |
| 12 | Bethel Court | distribution | 138.00 | 13.00 | |
| 13 | Big Grassy | transmission | 161.00 | | |
| 14 | Black Cat | distribution | 138.00 | 13.09 | |
| 15 | Blackfoot | distribution | 46.00 | 13.00 | |
| 16 | Blackfoot | transmission | 161.00 | 46.00 | 12.47 |
| 17 | Blackfoot | distribution | 161.00 | 138.00 | 12.98 |
| 18 | Bliss - attended | transmission | 138.00 | 13.80 | |
| 19 | Blue Gulch | distribution | 138.00 | 35.00 | |
| 20 | Boise Bench | transmission | 230.00 | 138.00 | 13.20 |
| 21 | Boise Bench | distribution | 138.00 | 35.00 | |
| 22 | Boise Bench | transmission | 138.00 | 69.00 | 12.98 |
| 23 | Boise Bench | transmission | 230.00 | 138.00 | 13.80 |
| 24 | Boise Bench | distribution | 35.00 | 13.00 | |
| 25 | Boise | distribution | 138.00 | 13.00 | |
| 26 | Borah | transmission | 345.00 | 230.00 | 13.80 |
| 27 | Border | distribution | 138.00 | 13.00 | |
| 28 | Border | distribution | 35.00 | | |
| 29 | Bowmont | distribution | 69.00 | 46.00 | 6.90 |
| 30 | Bowmont | distribution | 138.00 | 35.00 | |
| 31 | Bowmont | transmission | 138.00 | 69.00 | 12.98 |
| 32 | Bowmont | transmission | 138.00 | 69.00 | 12.47 |
| 33 | Bowmont | transmission | 230.00 | 138.00 | 13.80 |
| 34 | Brady | transmission | 230.00 | 138.00 | 13.80 |
| 35 | Brady | transmission | 138.00 | 46.00 | 12.47 |
| 36 | Brady | distribution | 46.00 | 13.00 | |
| 37 | Brownlee - attended | transmission | 230.00 | 13.80 | |
| 38 | Bruneau Bridge | distribution | 138.00 | 35.00 | |
| 39 | Bruneau Bridge | distribution | 138.00 | 36.20 | |
| 40 | Buckhorn | distribution | 69.00 | 35.00 | |

SUBSTATIONS (Continued)

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

| Capacity of Substation (In Service) (In MVa) | 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) | |
| 500 | 2 | | | | | 1 |
| 27 | 2 | | | | | 2 |
| 30 | 1 | | | | | 3 |
| 30 | 1 | | | | | 4 |
| 120 | 1 | | | | | 5 |
| 47 | 1 | | | | | 6 |
| 250 | 1 | | | | | 7 |
| 14 | 1 | | | | | 8 |
| 14 | 1 | | | | | 9 |
| 225 | 1 | | | | | 10 |
| 5 | 1 | | | | | 11 |
| 28 | 1 | | | | | 12 |
| | | | | | | 13 |
| 90 | 2 | | | | | 14 |
| 56 | 2 | | | | | 15 |
| 93 | 3 | 1 | | | | 16 |
| 135 | 1 | | | | | 17 |
| 86 | 3 | | | | | 18 |
| 48 | 2 | | | | | 19 |
| 448 | 2 | | | | | 20 |
| 70 | 2 | | | | | 21 |
| 125 | 3 | | | | | 22 |
| 448 | 2 | | | | | 23 |
| | | 1 | | | | 24 |
| 117 | 3 | | | | | 25 |
| 750 | 3 | 1 | | | | 26 |
| 11 | 1 | | | | | 27 |
| 5 | 3 | | | | | 28 |
| 8 | 3 | | | | | 29 |
| 30 | 1 | | | | | 30 |
| 46 | 1 | | | | | 31 |
| 47 | 1 | | | | | 32 |
| 600 | 2 | | | | | 33 |
| 312 | 3 | | | | | 34 |
| | | 1 | | | | 35 |
| 28 | 1 | 4 | | | | 36 |
| 752 | 5 | 1 | | | | 37 |
| 30 | 1 | | | | | 38 |
| 45 | 1 | | | | | 39 |
| 37 | 1 | | | | | 40 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Bucyrus | distribution | 46.00 | 7.20 | |
| 2 | Buhl | distribution | 46.00 | 13.20 | |
| 3 | Burley Rural | distribution | 69.00 | 13.00 | |
| 4 | Butler | distribution | 138.00 | 13.09 | |
| 5 | Caldwell | distribution | 138.00 | 13.00 | |
| 6 | Caldwell | transmission | 230.00 | 138.00 | |
| 7 | Caldwell | distribution | 138.00 | 13.09 | |
| 8 | Caldwell | transmission | 138.00 | 69.00 | 12.47 |
| 9 | Caldwell | transmission | 230.00 | 138.00 | 12.47 |
| 10 | Camas | distribution | 35.00 | | |
| 11 | Camas | distribution | 35.00 | 14.40 | |
| 12 | Canyon Creek | distribution | 138.00 | 36.20 | |
| 13 | Canyon Creek | transmission | 138.00 | 69.00 | 12.98 |
| 14 | Cartwright | distribution | 138.00 | 13.00 | |
| 15 | Cascade Power Plant - attended | transmission | 69.00 | 4.60 | |
| 16 | Cascade | distribution | 69.00 | 13.00 | |
| 17 | Cascade | distribution | 69.00 | 13.10 | |
| 18 | Cascade | distribution | 25.00 | | |
| 19 | Chestnut | distribution | 138.00 | 13.00 | |
| 20 | Chestnut | distribution | 138.00 | 13.09 | |
| 21 | Cinder | distribution | 46.00 | 13.00 | |
| 22 | Clear Lake - attended | transmission | 46.00 | 2.40 | |
| 23 | Cliff | transmission | 138.00 | 46.00 | 12.50 |
| 24 | Cliff | transmission | 138.00 | 46.00 | 12.95 |
| 25 | Cloverdale | distribution | 138.00 | 13.00 | |
| 26 | Cloverdale | distribution | 138.00 | 13.09 | |
| 27 | Council | distribution | 69.00 | 13.00 | |
| 28 | Crane Creek | distribution | 69.00 | 13.00 | |
| 29 | Crater | distribution | 46.00 | 13.00 | |
| 30 | Dale | distribution | 46.00 | 4.60 | |
| 31 | Dale | distribution | 46.00 | 13.00 | |
| 32 | Dale | distribution | 69.00 | 13.00 | |
| 33 | Dale | distribution | 138.00 | 36.20 | |
| 34 | Dale | transmission | 138.00 | 46.00 | 12.47 |
| 35 | Danskin- attended | transmission | 230.00 | 18.00 | |
| 36 | Danskin- attended | transmission | 230.00 | 138.00 | 13.80 |
| 37 | Danskin- attended | distribution | 18.00 | 4.16 | |
| 38 | Danskin- attended | transmission | 138.00 | 12.00 | |
| 39 | Danskin- attended | distribution | 35.00 | 13.80 | |
| 40 | Deen | distribution | 46.00 | 13.00 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 7 | 1 | 1 | | | | 1 |
| | | 1 | | | | 2 |
| 20 | 1 | | | | | 3 |
| 90 | 2 | | | | | 4 |
| 28 | 1 | | | | | 5 |
| 200 | 1 | | | | | 6 |
| 45 | 1 | | | | | 7 |
| 140 | 3 | | | | | 8 |
| 200 | 1 | | | | | 9 |
| 5 | 3 | 1 | | | | 10 |
| 10 | 3 | 1 | | | | 11 |
| 45 | 1 | | | | | 12 |
| 20 | 1 | | | | | 13 |
| 11 | 1 | | | | | 14 |
| 16 | 1 | | | | | 15 |
| 7 | 1 | | | | | 16 |
| 14 | 1 | | | | | 17 |
| 5 | 1 | | | | | 18 |
| 45 | 1 | | | | | 19 |
| 45 | 1 | | | | | 20 |
| 11 | 1 | | | | | 21 |
| 5 | 1 | | | | | 22 |
| 21 | 2 | 1 | | | | 23 |
| 10 | 1 | | | | | 24 |
| 45 | 1 | | | | | 25 |
| 45 | 1 | | | | | 26 |
| 14 | 1 | | | | | 27 |
| 11 | 1 | | | | | 28 |
| 11 | 1 | | | | | 29 |
| | | 1 | | | | 30 |
| | | 7 | | | | 31 |
| | | 1 | | | | 32 |
| 45 | 1 | | | | | 33 |
| 47 | 1 | | | | | 34 |
| 233 | 1 | | | | | 35 |
| 300 | 1 | | | | | 36 |
| 6 | 1 | | | | | 37 |
| 160 | 2 | | | | | 38 |
| 5 | 1 | | | | | 39 |
| 11 | 1 | | | | | 40 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Dietrich | distribution | 46.00 | 13.00 | |
| 2 | Don | distribution | 138.00 | 7.60 | |
| 3 | Don | distribution | 138.00 | 13.20 | |
| 4 | Don | distribution | 138.00 | 13.00 | |
| 5 | DRAM | distribution | 138.00 | 13.09 | |
| 6 | DRAM | transmission | 230.00 | 138.00 | 13.80 |
| 7 | DRAM | distribution | 138.00 | 12.47 | |
| 8 | DRAM | distribution | 138.00 | 13.00 | |
| 9 | Duffin | distribution | 138.00 | 35.00 | |
| 10 | Eagle | distribution | 138.00 | 13.09 | |
| 11 | Eastgate | distribution | 138.00 | | |
| 12 | Eastgate | distribution | 138.00 | 13.00 | |
| 13 | Eckert | distribution | 138.00 | 36.20 | |
| 14 | Eden | distribution | 138.00 | 36.20 | |
| 15 | Eden | transmission | 138.00 | 46.00 | 12.98 |
| 16 | Elkhorn | distribution | 138.00 | 12.47 | |
| 17 | Elkhorn | distribution | 138.00 | 13.00 | |
| 18 | Elmore | distribution | 138.00 | 35.00 | |
| 19 | Elmore | transmission | 138.00 | 69.00 | 12.50 |
| 20 | Elmore | transmission | 138.00 | 69.00 | 12.98 |
| 21 | Emmett | distribution | 138.00 | | |
| 22 | Emmett | transmission | 138.00 | 69.00 | 12.47 |
| 23 | Falls | distribution | 46.00 | 13.00 | |
| 24 | Filer | distribution | 46.00 | 13.00 | |
| 25 | Flat Top | distribution | 46.00 | 13.00 | |
| 26 | Flying H | distribution | 69.00 | 2.40 | |
| 27 | Fort Hall | distribution | 46.00 | 13.00 | |
| 28 | Fossil Gulch | distribution | 138.00 | 35.00 | |
| 29 | Fremont | transmission | 138.00 | 46.00 | 12.50 |
| 30 | Gary | distribution | 138.00 | 13.09 | |
| 31 | Gary | distribution | 138.00 | 13.00 | |
| 32 | Gem | distribution | 69.00 | 13.00 | |
| 33 | Gem | distribution | 69.00 | | |
| 34 | Glenns Ferry | distribution | 138.00 | 13.00 | |
| 35 | Gooding Rural | distribution | 46.00 | 13.00 | |
| 36 | Golden Valley | distribution | 69.00 | 13.00 | |
| 37 | Goshen | transmission | 345.00 | 161.00 | 69.00 |
| 38 | Gowen Substation | distribution | 138.00 | 35.00 | |
| 39 | Grindstone | distribution | 35.00 | | |
| 40 | Grindstone | distribution | 35.00 | 2.40 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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. |
|---|---|---|---|---|---|---|
| 11 | 1 | | | | | 1 |
| | | 1 | | | | 2 |
| 180 | 6 | 1 | | | | 3 |
| 44 | 1 | | | | | 4 |
| 168 | 6 | | | | | 5 |
| 212 | 2 | | | | | 6 |
| 28 | 1 | | | | | 7 |
| 28 | 1 | | | | | 8 |
| 60 | 2 | | | | | 9 |
| 67 | 2 | | | | | 10 |
| 45 | 1 | | | | | 11 |
| 30 | 1 | | | | | 12 |
| 30 | 1 | | | | | 13 |
| 45 | 1 | | | | | 14 |
| 20 | 1 | | | | | 15 |
| 11 | 1 | | | | | 16 |
| 11 | 1 | | | | | 17 |
| 28 | 1 | | | | | 18 |
| 25 | 1 | | | | | 19 |
| 20 | 1 | | | | | 20 |
| 45 | 1 | | | | | 21 |
| 47 | 1 | | | | | 22 |
| 28 | 2 | | | | | 23 |
| 14 | 1 | | | | | 24 |
| 17 | 2 | | | | | 25 |
| 20 | 2 | | | | | 26 |
| 14 | 1 | 1 | | | | 27 |
| 28 | 1 | | | | | 28 |
| 67 | 3 | 1 | | | | 29 |
| 37 | 1 | | | | | 30 |
| 28 | 1 | | | | | 31 |
| 9 | 1 | | | | | 32 |
| 14 | 1 | | | | | 33 |
| 11 | 1 | | | | | 34 |
| 20 | 2 | | | | | 35 |
| 14 | 1 | 1 | | | | 36 |
| 908 | 4 | | | | | 37 |
| 45 | 1 | | | | | 38 |
| 7 | 1 | | | | | 39 |
| 7 | 1 | | | | | 40 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Grove | distribution | 138.00 | 13.09 | |
| 2 | Grove | distribution | 138.00 | 13.00 | |
| 3 | Hagerman | distribution | 46.00 | 13.00 | |
| 4 | Hagerman | distribution | 69.00 | 13.00 | |
| 5 | Hailey | distribution | 138.00 | 13.00 | |
| 6 | Happy Valley | distribution | 138.00 | 13.09 | |
| 7 | Haven | distribution | 138.00 | 35.00 | |
| 8 | Haven | transmission | 138.00 | 46.00 | |
| 9 | Hemingway | transmission | 500.00 | 230.00 | 34.50 |
| 10 | Hewlett Packard | distribution | 138.00 | 13.00 | |
| 11 | Hidden Springs | distribution | 138.00 | 13.00 | |
| 12 | Highland | distribution | 138.00 | 13.00 | |
| 13 | Hill | distribution | 138.00 | 13.00 | |
| 14 | Hillsdale | distribution | 138.00 | | |
| 15 | Homedale | distribution | 69.00 | 13.00 | |
| 16 | Horse Flat | transmission | 230.00 | 138.00 | 13.80 |
| 17 | Horseshoe Bend | distribution | 35.00 | | |
| 18 | Horseshoe Bend | distribution | 69.00 | 36.20 | |
| 19 | Horseshoe Bend | distribution | 69.00 | 25.00 | |
| 20 | Huston | distribution | 69.00 | 13.00 | |
| 21 | Hulen | distribution | 46.00 | 13.00 | |
| 22 | Hunt | transmission | 230.00 | 138.00 | 13.80 |
| 23 | Hydra | distribution | 138.00 | 36.20 | |
| 24 | Island | distribution | 69.00 | 13.00 | |
| 25 | Jefferson | transmission | 161.00 | | |
| 26 | Jerome | distribution | 138.00 | 13.00 | |
| 27 | Jerome | distribution | 138.00 | 13.09 | |
| 28 | Julion Clawson | distribution | 138.00 | 35.00 | |
| 29 | Joplin | distribution | 138.00 | 13.00 | |
| 30 | Joplin | distribution | 138.00 | 35.00 | |
| 31 | Justice | transmission | 230.00 | 138.00 | 13.80 |
| 32 | Karcher | distribution | 138.00 | 13.00 | |
| 33 | Kenyon | distribution | 69.00 | 13.00 | |
| 34 | Ketchum | distribution | 138.00 | 13.00 | |
| 35 | Kimberly | distribution | 138.00 | 13.09 | |
| 36 | Kinport | transmission | 161.00 | 46.00 | 13.20 |
| 37 | Kinport | transmission | 230.00 | 138.00 | 12.47 |
| 38 | Kinport | transmission | 230.00 | 138.00 | 13.80 |
| 39 | Kinport | transmission | 345.00 | 230.00 | 13.80 |
| 40 | Kramer | distribution | 138.00 | 35.00 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|---|
| 90 | 2 | | | | | 1 |
| 45 | 1 | | | | | 2 |
| 14 | 1 | | | | | 3 |
| 6 | 1 | | | | | 4 |
| 37 | 1 | | | | | 5 |
| 30 | 1 | | | | | 6 |
| 20 | 1 | | | | | 7 |
| 47 | 1 | | | | | 8 |
| 1000 | 3 | 1 | | | | 9 |
| 37 | 1 | | | | | 10 |
| 11 | 1 | | | | | 11 |
| 30 | 1 | | | | | 12 |
| 73 | 2 | | | | | 13 |
| 45 | 1 | | | | | 14 |
| 34 | 2 | | | | | 15 |
| 100 | 1 | | | | | 16 |
| 7 | 1 | | | | | 17 |
| 22 | 1 | | | | | 18 |
| 7 | 1 | | | | | 19 |
| 14 | 1 | | | | | 20 |
| 14 | 1 | | | | | 21 |
| 336 | 3 | | | | | 22 |
| 90 | 2 | | | | | 23 |
| 20 | 1 | | | | | 24 |
| | | | | | | 25 |
| 37 | 1 | | | | | 26 |
| 37 | 1 | | | | | 27 |
| 56 | 2 | | | | | 28 |
| 28 | 1 | | | | | 29 |
| 30 | 1 | | | | | 30 |
| 300 | 1 | | | | | 31 |
| 20 | 1 | | | | | 32 |
| 25 | 2 | | | | | 33 |
| 75 | 2 | | | | | 34 |
| 45 | 1 | 1 | | | | 35 |
| | | 7 | | | | 36 |
| 300 | 1 | | | | | 37 |
| 300 | 1 | | | | | 38 |
| 1000 | 3 | 1 | | | | 39 |
| 20 | 1 | | | | | 40 |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/Q4 |
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## 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 | Kramer | distribution | 138.00 | 36.20 | |
| 2 | Kuna | distribution | 138.00 | 13.00 | |
| 3 | Lake | distribution | 69.00 | 13.00 | |
| 4 | Lake Fork | distribution | 138.00 | 36.20 | |
| 5 | Lake Fork | transmission | 138.00 | 69.00 | 12.50 |
| 6 | Lamb | distribution | 138.00 | 13.00 | |
| 7 | Langley Gulch- attended | transmission | 230.00 | 138.00 | 13.80 |
| 8 | Langley Gulch- attended | transmission | 230.00 | | |
| 9 | Langley Gulch- attended | transmission | 230.00 | 150.00 | |
| 10 | Lincoln | distribution | 138.00 | 13.09 | |
| 11 | Linden | distribution | 138.00 | 13.00 | |
| 12 | Locust | distribution | 138.00 | 36.20 | |
| 13 | Locust | transmission | 230.00 | 138.00 | 13.80 |
| 14 | Lower Malad - attended | transmission | 138.00 | 7.20 | |
| 15 | Lower Salmon - attended | transmission | 138.00 | 13.80 | |
| 16 | Map Rock | distribution | 69.00 | 13.00 | |
| 17 | McCall | distribution | 138.00 | 13.09 | |
| 18 | McCall | distribution | 138.00 | 36.20 | |
| 19 | Melba | distribution | 69.00 | 13.00 | |
| 20 | Meridian | distribution | 138.00 | 13.00 | |
| 21 | Micron | distribution | 138.00 | 13.09 | |
| 22 | Micron | distribution | 138.00 | 13.00 | |
| 23 | Midpoint | transmission | 230.00 | 138.00 | 13.80 |
| 24 | Midpoint | transmission | 345.00 | 230.00 | 13.80 |
| 25 | Midpoint | transmission | 500.00 | 345.00 | |
| 26 | Midrose | distribution | 138.00 | 13.09 | |
| 27 | Milner | transmission | 138.00 | 69.00 | 12.47 |
| 28 | Milner | distribution | 69.00 | 46.00 | 6.90 |
| 29 | Milner | distribution | 138.00 | 35.00 | |
| 30 | Milner PP - attended | transmission | 138.00 | 13.80 | |
| 31 | Moonstone | distribution | 138.00 | 35.00 | |
| 32 | Mora | distribution | 138.00 | 13.09 | |
| 33 | Mora | distribution | 138.00 | 36.20 | |
| 34 | Moreland | distribution | 46.00 | 35.00 | 12.47 |
| 35 | Mountain Home | distribution | 69.00 | 13.00 | |
| 36 | Mountain Home Air Force Base | distribution | 69.00 | 13.00 | |
| 37 | Mountain Home Air Force Base | distribution | 138.00 | 13.00 | |
| 38 | Nampa | transmission | 230.00 | 138.00 | 13.80 |
| 39 | Nampa | distribution | 138.00 | 13.00 | |
| 40 | New Meadows | distribution | 138.00 | 36.20 | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report (Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Number of Units<br>(j) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 30 | 1 | | | | | 1 |
| 28 | 1 | | | | | 2 |
| 14 | 1 | | | | | 3 |
| 30 | 1 | | | | | 4 |
| 20 | 1 | | | | | 5 |
| 30 | 1 | | | | | 6 |
| 636 | 2 | | | | | 7 |
| 410 | 2 | | | | | 8 |
| | | 1 | | | | 9 |
| 14 | 1 | | | | | 10 |
| 58 | 2 | | | | | 11 |
| 134 | 3 | | | | | 12 |
| 600 | 2 | | | | | 13 |
| 16 | 1 | | | | | 14 |
| 70 | 4 | | | | | 15 |
| 13 | 1 | | | | | 16 |
| 22 | 1 | | | | | 17 |
| 30 | 1 | | | | | 18 |
| 11 | 1 | | | | | 19 |
| 60 | 2 | | | | | 20 |
| 40 | 2 | | | | | 21 |
| 40 | 2 | | | | | 22 |
| 200 | 1 | | | | | 23 |
| 1400 | 2 | 1 | | | | 24 |
| 1500 | 3 | 1 | | | | 25 |
| 45 | 1 | | | | | 26 |
| 125 | 3 | 1 | | | | 27 |
| 8 | 3 | 1 | | | | 28 |
| 50 | 2 | | | | | 29 |
| 60 | 1 | | | | | 30 |
| 20 | 1 | | | | | 31 |
| 45 | 1 | | | | | 32 |
| 45 | 1 | | | | | 33 |
| 7 | 3 | 1 | | | | 34 |
| 28 | 1 | | | | | 35 |
| | | 1 | | | | 36 |
| 34 | 1 | | | | | 37 |
| 300 | 1 | | | | | 38 |
| 87 | 3 | | | | | 39 |
| 22 | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | New Plymouth | distribution | 69.00 | 13.00 | |
| 2 | Northview | distribution | 138.00 | | |
| 3 | Notch Butte | distribution | 138.00 | 13.09 | |
| 4 | Orchard | distribution | 69.00 | 36.20 | |
| 5 | Orchard | distribution | 69.00 | | |
| 6 | Parma | distribution | 69.00 | 13.00 | |
| 7 | Parma | distribution | 69.00 | 35.00 | |
| 8 | Paul | distribution | 138.00 | 35.00 | |
| 9 | Paul | distribution | 138.00 | 36.20 | |
| 10 | Payette | distribution | 138.00 | 13.00 | |
| 11 | Pingree | transmission | 138.00 | 46.00 | 12.50 |
| 12 | Pingree | distribution | 138.00 | 35.00 | |
| 13 | Pleasant Valley | distribution | 138.00 | 35.00 | |
| 14 | Pleasant Valley | distribution | 138.00 | 36.20 | |
| 15 | Pocatello | distribution | 46.00 | 13.00 | |
| 16 | Pocket | distribution | 138.00 | 36.20 | |
| 17 | Poleline | distribution | 138.00 | 13.09 | |
| 18 | **Populus** | transmission | 345.00 | | |
| 19 | Portneuf | distribution | 138.00 | 35.00 | |
| 20 | Portneuf | distribution | 46.00 | 35.00 | |
| 21 | Rockford | distribution | 46.00 | 13.00 | |
| 22 | Russett | distribution | 138.00 | 13.00 | |
| 23 | Sailor Creek | distribution | 138.00 | 2.40 | |
| 24 | Sailor Creek | distribution | 138.00 | 35.00 | |
| 25 | Salmon | distribution | 69.00 | 13.00 | |
| 26 | Salmon | distribution | 69.00 | 34.50 | 12.47 |
| 27 | Salmon | distribution | 69.00 | 7.20 | |
| 28 | Shoshone | distribution | 46.00 | 13.00 | |
| 29 | Shoshone | distribution | 46.00 | 7.20 | |
| 30 | Shoshone Falls - attended | transmission | 46.00 | 2.30 | |
| 31 | Shoshone Falls - attended | transmission | 46.00 | 6.60 | |
| 32 | Silver | distribution | 138.00 | 35.00 | |
| 33 | Simplot | distribution | 138.00 | 13.00 | |
| 34 | Sinker Creek | distribution | 138.00 | 35.00 | |
| 35 | Siphon | distribution | 138.00 | 35.00 | |
| 36 | South Park | distribution | 46.00 | 13.00 | |
| 37 | Spring Valley | distribution | 138.00 | 2.40 | |
| 38 | Star | distribution | 138.00 | 13.09 | |
| 39 | Starkey | transmission | 138.00 | 69.00 | 12.47 |
| 40 | State | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | Number of Units<br>(j) | Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| 13 | 1 | | | | | 1 |
| 45 | 1 | | | | | 2 |
| 14 | 1 | | | | | 3 |
| 8 | 1 | | | | | 4 |
| 33 | 1 | | | | | 5 |
| 14 | 1 | | | | | 6 |
| 20 | 1 | | | | | 7 |
| 30 | 1 | 1 | | | | 8 |
| 45 | 1 | | | | | 9 |
| 32 | 3 | | | | | 10 |
| 67 | 3 | | | | | 11 |
| 34 | 2 | | | | | 12 |
| 30 | 1 | | | | | 13 |
| 45 | 1 | | | | | 14 |
| 60 | 2 | | | | | 15 |
| 45 | 1 | | | | | 16 |
| 30 | 1 | | | | | 17 |
| | | | | | | 18 |
| 30 | 1 | | | | | 19 |
| | | 1 | | | | 20 |
| 25 | 2 | | | | | 21 |
| 30 | 1 | | | | | 22 |
| 21 | 2 | | | | | 23 |
| 28 | 1 | | | | | 24 |
| 14 | 1 | 4 | | | | 25 |
| 10 | 3 | 1 | | | | 26 |
| | | 1 | | | | 27 |
| 13 | 1 | | | | | 28 |
| 2 | 3 | | | | | 29 |
| 4 | 1 | | | | | 30 |
| 14 | 1 | | | | | 31 |
| 20 | 1 | | | | | 32 |
| 53 | 2 | | | | | 33 |
| 20 | 1 | | | | | 34 |
| 55 | 2 | | | | | 35 |
| 14 | 1 | | | | | 36 |
| 11 | 1 | | | | | 37 |
| 30 | 1 | | | | | 38 |
| 30 | 1 | | | | | 39 |
| 58 | 2 | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| Idaho Power Company | (1) [X] An Original (2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | Sterling | distribution | 46.00 | 13.00 | |
| 2 | Stoddard | distribution | 138.00 | 13.00 | |
| 3 | Strike Power Plant - attended | transmission | 138.00 | 13.80 | |
| 4 | Sugar | distribution | 138.00 | 35.00 | |
| 5 | Swan Falls - attended | transmission | 138.00 | 6.90 | |
| 6 | Taber | distribution | 46.00 | 13.00 | |
| 7 | Tamarack | distribution | 138.00 | 2.40 | |
| 8 | Ten Mile | distribution | 138.00 | 13.09 | |
| 9 | Terry | distribution | 138.00 | 13.09 | |
| 10 | Terry | distribution | 138.00 | 13.00 | |
| 11 | Thousand Springs - attended | transmission | 46.00 | 7.20 | |
| 12 | Three Mile Knoll | transmission | 345.00 | | |
| 13 | Toponis | distribution | 138.00 | 33.00 | |
| 14 | Twin Falls | distribution | 138.00 | 13.09 | |
| 15 | Twin Falls | transmission | 138.00 | 46.00 | 12.98 |
| 16 | Twin Falls PP - attended | transmission | 138.00 | 7.20 | |
| 17 | Twin Falls PP - attended | transmission | 138.00 | 13.20 | |
| 18 | Tyhee | distribution | 46.00 | 13.00 | |
| 19 | Upper Malad - attended | transmission | 45.00 | 7.20 | |
| 20 | Upper Salmon- attended | transmission | 138.00 | 7.20 | |
| 21 | Ustick | distribution | 138.00 | 13.00 | |
| 22 | Vallivue | distribution | 138.00 | 13.09 | |
| 23 | Victory | distribution | 138.00 | 13.00 | |
| 24 | Victory | distribution | 138.00 | 13.09 | |
| 25 | Ware | distribution | 69.00 | 13.00 | |
| 26 | Weiser | distribution | 69.00 | 13.00 | |
| 27 | Weiser | transmission | 138.00 | 69.00 | 12.47 |
| 28 | Wilder | distribution | 69.00 | 13.00 | |
| 29 | Willis | distribution | 138.00 | 13.09 | |
| 30 | Willow Creek | distribution | 138.00 | 13.00 | |
| 31 | Wye | distribution | 138.00 | 13.00 | |
| 32 | Wye | distribution | 138.00 | 13.09 | |
| 33 | Zilog | distribution | 138.00 | 13.09 | |
| 34 | | | | | |
| 35 | | | | | |
| 36 | The above are all State of Idaho | | | | |
| 37 | | | | | |
| 38 | Montana: | | | | |
| 39 | Mill Creek | transmission | 230.00 | | |
| 40 | Peterson | transmission | 230.00 | 69.00 | 13.20 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
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SUBSTATIONS (Continued)

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| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 11 | 2 | | | | | 1 |
| 28 | 1 | | | | | 2 |
| 104 | 3 | | | | | 3 |
| 28 | 2 | | | | | 4 |
| 34 | 1 | | | | | 5 |
| 6 | 1 | | | | | 6 |
| 11 | 1 | | | | | 7 |
| 90 | 2 | | | | | 8 |
| 20 | 1 | | | | | 9 |
| 50 | 2 | | | | | 10 |
| 8 | 1 | | | | | 11 |
| | | | | | | 12 |
| 30 | 1 | | | | | 13 |
| 82 | 2 | | | | | 14 |
| 50 | 2 | | | | | 15 |
| 13 | 1 | | | | | 16 |
| 72 | 1 | | | | | 17 |
| 14 | 1 | | | | | 18 |
| 8 | 1 | | | | | 19 |
| 42 | 4 | | | | | 20 |
| 77 | 2 | | | | | 21 |
| 30 | 1 | | | | | 22 |
| 45 | 1 | | | | | 23 |
| 30 | 1 | | | | | 24 |
| 20 | 1 | 1 | | | | 25 |
| 27 | 2 | | | | | 26 |
| 42 | 1 | | | | | 27 |
| 14 | 1 | | | | | 28 |
| 30 | 1 | | | | | 29 |
| 11 | 1 | | | | | 30 |
| 60 | 2 | | | | | 31 |
| 37 | 1 | | | | | 32 |
| 45 | 1 | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| 30 | 3 | 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<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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 | | | | | |
| 2 | Nevada: | | | | |
| 3 | **Valmy - attended** | transmission | 345.00 | 18.00 | |
| 4 | **Valmy - attended** | transmission | 345.00 | 22.00 | |
| 5 | Wells | transmission | 138.00 | 69.00 | 13.00 |
| 6 | | | | | |
| 7 | Oregon: | | | | |
| 8 | Adrian | distribution | 69.00 | 13.00 | |
| 9 | **Boardman - attended** | transmission | 500.00 | 24.00 | |
| 10 | **Boardman - attended** | transmission | 230.00 | 7.20 | |
| 11 | **Boardman - attended** | transmission | 24.00 | 7.20 | |
| 12 | **Burns** | transmission | 500.00 | | |
| 13 | Cairo | distribution | 69.00 | 13.00 | |
| 14 | Hells Canyon - attended | transmission | 230.00 | 13.80 | |
| 15 | Hells Canyon - attended | distribution | 69.00 | 0.50 | |
| 16 | Hines | transmission | 138.00 | 115.00 | 12.47 |
| 17 | **Hurricane** | transmission | 230.00 | | |
| 18 | Jacobson Gulch | distribution | 69.00 | 2.40 | |
| 19 | Malheur Butte | distribution | 69.00 | 34.50 | |
| 20 | Nyssa | distribution | 69.00 | 13.00 | |
| 21 | Ontario | distribution | 138.00 | 13.00 | |
| 22 | Ontario | transmission | 138.00 | 69.00 | 12.47 |
| 23 | Ontario | transmission | 230.00 | 138.00 | 13.80 |
| 24 | Ontario | transmission | 138.00 | 69.00 | 12.98 |
| 25 | Ontario | transmission | 138.00 | 69.00 | 13.09 |
| 26 | Ontario | transmission | 138.00 | 69.00 | 12.50 |
| 27 | Ore-Ida | distribution | 69.00 | 13.00 | |
| 28 | Oxbow - attended | transmission | 138.00 | 69.00 | 13.00 |
| 29 | Oxbow - attended | transmission | 230.00 | 13.80 | |
| 30 | Oxbow - attended | transmission | 230.00 | 138.00 | 13.80 |
| 31 | Quartz | transmission | 138.00 | 69.00 | 12.50 |
| 32 | Quartz | transmission | 230.00 | 138.00 | 12.98 |
| 33 | Quartz | transmission | 138.00 | 69.00 | 12.98 |
| 34 | **Summer Lake** | transmission | 500.00 | | |
| 35 | Vale | distribution | 69.00 | 13.00 | |
| 36 | | | | | |
| 37 | Washington: | | | | |
| 38 | **Walla Walla** | transmission | 230.00 | | |
| 39 | | | | | |
| 40 | Wyoming: | | | | |

| Name of Respondent<br>Idaho Power Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>04/18/2018 | Year/Period of Report<br>End of 2017/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)<br>(f) | Number of Transformers In Service<br>(g) | Number of Spare Transformers<br>(h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Type of Equipment<br>(i) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Number of Units<br>(j) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT<br>Total Capacity (In MVa)<br>(k) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| 315 | 1 | | | | | 3 |
| 300 | 1 | | | | | 4 |
| 25 | 3 | 1 | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| 11 | 1 | | | | | 8 |
| 685 | 3 | | | | | 9 |
| 55 | 1 | | | | | 10 |
| 55 | 1 | | | | | 11 |
| | | | | | | 12 |
| 20 | 1 | | | | | 13 |
| 560 | 3 | | | | | 14 |
| 1 | 1 | | | | | 15 |
| 50 | 1 | | | | | 16 |
| | | | | | | 17 |
| 11 | 1 | | | | | 18 |
| 11 | 3 | 1 | | | | 19 |
| 28 | 2 | | | | | 20 |
| 67 | 2 | | | | | 21 |
| 47 | 1 | | | | | 22 |
| 400 | 2 | | | | | 23 |
| 93 | 2 | | | | | 24 |
| | | 1 | | | | 25 |
| | | 1 | | | | 26 |
| 28 | 1 | | | | | 27 |
| 13 | 3 | 1 | | | | 28 |
| 259 | 2 | | | | | 29 |
| 100 | 1 | | | | | 30 |
| 25 | 1 | | | | | 31 |
| 167 | 3 | 1 | | | | 32 |
| 20 | 1 | | | | | 33 |
| | | | | | | 34 |
| 14 | 1 | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/Q4 |

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Jim Bridger - attended | transmission | 345.00 | 22.00 | 34.50 |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | Transformers-distribution substations under 10,000 | | | | |
| 8 | KVA 65 unattended. | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | | | | | |
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| 38 | | | | | |
| 39 | | | | | |
| 40 | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Idaho Power Company | (1) [X] An Original<br>(2) [ ] A Resubmission | 04/18/2018 | End of 2017/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. |
|---|---|---|---|---|---|---|
| 2244 | 4 | | | | | 1 |
| | | | | | | 2 |
| | | | | | | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| 228 | | | | | | 8 |
| | | | | | | 9 |
| | | | | | | 10 |
| | | | | | | 11 |
| | | | | | | 12 |
| | | | | | | 13 |
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| | | | | | | 40 |

***Schedule Page: 426 Line No.: 1 Column: a***

PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Adelaide station. Ownership interest varies by terminal. 100% of the capacity is reported.

***Schedule Page: 426 Line No.: 1 Column: f***

For all of column F:
Top rating capacity reported unless otherwise noted.

***Schedule Page: 426 Line No.: 7 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Antelope station. Ownership interest varies by terminal. 100% of the capacity reported.

***Schedule Page: 426 Line No.: 13 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Big Grassy station. Ownership interest varies by terminal.

***Schedule Page: 426 Line No.: 26 Column: a***

PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Borah station. Ownership interest varies by terminal. 100% of the capacity is reported.

***Schedule Page: 426.2 Line No.: 37 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Goshen station. Ownership interest varies by terminal. 100% of the capacity reported.

***Schedule Page: 426.3 Line No.: 9 Column: a***

PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway station. Ownership interest varies by terminal. 100% of the capacity is reported.

***Schedule Page: 426.3 Line No.: 25 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Jefferson station. Ownership interest varies by terminal.

***Schedule Page: 426.3 Line No.: 39 Column: a***

PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Kinport station. Ownership interest varies by terminal. 100% of the capacity is reported.

***Schedule Page: 426.4 Line No.: 25 Column: a***

PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Midpoint station. Ownership interest varies by terminal. 100% of the capacity is reported.

***Schedule Page: 426.5 Line No.: 18 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station. Ownership interest varies by terminal.

***Schedule Page: 426.6 Line No.: 12 Column: a***

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Three Mile Knoll station. Ownership interest varies by terminal.

***Schedule Page: 426.6 Line No.: 39 Column: a***

Idaho Power has 32% ownership interest in certain transmission related equipment located at Northwestern Energy's Mill Creek Station.

***Schedule Page: 426.7 Line No.: 3 Column: a***

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the capacity reported.

***Schedule Page: 426.7 Line No.: 4 Column: a***

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the capacity reported.

**Schedule Page: 426.7 Line No.: 9 Column: a**

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

**Schedule Page: 426.7 Line No.: 10 Column: a**

Jointly owned with 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.: 11 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.: 12 Column: a**

Idaho Power has a 22% ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Burns station.

**Schedule Page: 426.7 Line No.: 17 Column: a**

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Hurricane station. Ownership interest varies by terminal.

**Schedule Page: 426.7 Line No.: 34 Column: a**

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Summer Lake station. Ownership interest varies by terminal.

**Schedule Page: 426.7 Line No.: 38 Column: a**

Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Walla Walla station. Ownership interest varies by terminal.

**Schedule Page: 426.8 Line No.: 1 Column: a**

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership. 100% of the capacity is reported.

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## 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 | | | | |
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| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | **Non-power Goods or Services Provided for Affiliate** | | | |
| 21 | 06 | IDACORP, INC. | 417420 | 430,847 |
| 22 | | | 922000 | 40,958 |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
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**ANNUAL REPORT**
**OREGON SUPPLEMENT TO FERC FORM 1**

**for**
**MULTI-STATE ELECTRIC COMPANIES**

**INDEX**

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 | $ 60,165,308 | $ 59,061,141 |
| 3 | Operating Expenses | | | |
| 4 | Operation Expenses (401)........ | 8-11 | 35,542,454 | 38,818,292 |
| 5 | Maintenance Expenses (402)........ | 8-11 | 3,083,590 | 3,370,522 |
| 6 | Depreciation Expense (403)........ | 12 | 6,695,418 | 5,937,323 |
| 7 | Amort. & Depl. of Utility Plant (404-405)........ | 12 | 267,292 | 287,104 |
| 8 | Amort. of Utility Plant Acq. Adj. (406)........ | 12 | 1,386 | - |
| 9 | Amort. of Property Losses, Unrecovered Plant and Regulatory.......... Study Costs (407-411) ........ | 12 | (5,568) | (2,128) |
| 10 | Accretion Expense (411)........ | 12 | 9,829 | 10,127 |
| 11 | Amort. of Conversion Expenses (407)........ | 12 | | |
| 12 | Taxes Other Than Income Taxes (408.1)........ | 13 | 2,418,153 | 2,316,395 |
| 13 | Regulatory Debits/Credits........ | 14 | 1,003,154 | 167,068 |
| 14 | Income Taxes - Federal (409.1)........ | 14 | 1,229,795 | (989,716) |
| 15 | - Other (409.1)........ | 15 | 334,362 | (982) |
| 16 | Provision for Deferred Inc. Taxes (410.1)........ | 16-23 | 1,972,350 | 2,245,922 |
| 17 | (Less) Provision for Deferred Income Taxes - Cr.(411.1)........ | 16-23 | (2,892,837) | (948,203) |
| 18 | Investment Tax Credit Adj. - Net (411.4)........ | 24 | 319,752 | 13,162 |
| 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)........ | | 49,979,129 | 51,224,886 |
| 22 | Net Utility Operating Income (Total of line 2 less 20)........ | | $ 10,186,180 | $ 7,836,254 |

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) regul used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (S Account 442 of the Uniform System of Accounts. Ex 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) | Amount for Previous Year (c) | MEGAWATT HOURS SOLD Amount for Current Year (d) | Amount for Previous Year (e) | AVG NO OF CUSTOMERS PER MONTH Number for Current Year (f) | Number for Previous Year (g) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 1 | Sales of Electricity | | | | | | | 1 |
| 2 | (440) Residential Sales.......................................... | $ 19,292,567 | $ 18,068,244 | 193,127 | 179,315 | 13,423 | 13,396 | 2 |
| 3 | (442) Commercial and Industrial Sales | | | | | | | 3 |
| 4 | Small (or Commercial) (See Instr. 4) (1)............... | 18,585,147 | 19,320,455 | 219,243 | 224,928 | 5,473 | 5,412 | 4 |
| 5 | Large (or Industrial) (See Instr. 4) (2).................... | 15,812,491 | 15,737,349 | 268,873 | 262,189 | 7 | 7 | 5 |
| 6 | (444) Public Street and Highway Lighting.............. | 143,799 | 145,807 | 924 | 931 | 34 | 33 | 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................ | 53,834,005* | 53,271,854* | 682,167 ** | 667,364 | 18,937 | 18,848 | 10 |
| 11 | (447) Sales for Resale - Opportunity Non-Firm........ | 1,549,531 | 1,176,057 | 99,133 | 55,333 | | | 11 |
| 12 | TOTAL Sales of Electricity................................ | 55,383,535 | 54,447,911 | 781,300 | 722,696 | 18,937 | 18,848 | 12 |
| 13 | (Less) (449.1) Provision for Rate Refunds.............. | - | - | | | | | 13 |
| 14 | TOTAL Revenue Net of Provision for Refunds.... | 55,383,535 | 54,447,911 | | | | | 14 |
| 15 | Other Operating Revenues | | | | | | | 15 |
| 16 | (450) Forfeited Discounts....................................... | | | | | | | 16 |
| 17 | (451) Miscellaneous Service Revenues.................. | 82,769 | 82,758 | | | | | 17 |
| 18 | (453) Sales of Water and Water Power.................. | | | | | | | 18 |
| 19 | (454) Rent from Electric Property........................... | 748,075 | 710,042 | | | | | 19 |
| 20 | (455) Interdepartmental Rents.............................. | | | | | | | 20 |
| 21 | (456) Other Electric Revenues............................... | 3,950,930 | 3,820,429 | | | | | 21 |
| 22 | | | | | | | | 22 |
| 23 | | | | | | | | 23 |
| 24 | | | | | | | | 24 |
| 25 | TOTAL Other Operating Revenues.................... | 4,781,773 | 4,613,230 | | | | | 25 |
| 26 | TOTAL Electric Operating Revenues................. | $ 60,165,308 | $ 59,061,140 | | | | | 26 |

* Includes -$651,051 unbilled revenues.

** Includes -6,079 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 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 "Electri 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 revenu account subheading.
3. Where the same customers are served under more than or 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 | 197,078 | $ 19,865,928 | 13,423 | 14,682 | 10.08 |
| 3 | 03 - Residential-Mastered Metered | | | | | |
| 4 | 05 - Residential - TOD | | | | | |
| 5 | 15 - Dusk to Dawn customer Lighting | 185 | 51,248 | | | 27.70 |
| 6 | **Residential - Billed** | **197,263** | **19,917,176** | **13,423** | **14,696** | **10.10** |
| 7 | Residential - Unbilled | (4,136) | (455,145) | | | 11.00 |
| 8 | Bridger Depr & Boardman Decomm | | (169,464) | | | |
| 9 | **Total 440** | **193,127** | **19,292,567** | **13,423** | **14,388** | **9.99** |
| 10 | | | | | | |
| 11 | 442 - Commercial and Industrial Sales: | | | | | |
| 12 | 07 - General Service | 19,146 | 2,004,544 | 2,489 | 7,692 | 10.47 |
| 13 | 09P - General Service | 15,961 | 1,090,811 | 5 | 3,192,200 | 6.83 |
| 14 | 09S - General Service | 119,284 | 9,301,472 | 928 | | |
| 15 | 09T - General Service | 3,035 | 205,645 | 1 | | |
| 16 | 15 - Dusk to dawn customer lighting | 249 | 56,730 | 0 | | 22.78 |
| 17 | 19P - Uniform rate contracts | 166,366 | 10,279,366 | 6 | 27,727,667 | 6.18 |
| 18 | 19S - Uniform rate contracts | 0 | 0 | 0 | | |
| 19 | 19T - Uniform rate contracts | 102,709 | 5,908,986 | 1 | | |
| 20 | 24S - Irrigation and soil drainage pump | 63,302 | 6,167,408 | 2,048 | 30,909 | 9.74 |
| 21 | 40 - General Service | 5 | 535 | 2 | 2,500 | 10.70 |
| 22 | **Commercial & Industrial - Billed** | **490,057** | **35,015,497** | **5,480** | **89,426** | **7.15** |
| 23 | Commercial & Industrial - Unbilled | (1,942) | (195,541) | | | 10.07 |
| 24 | Bridger Depr & Boardman Decomm | | (422,316) | | | |
| 25 | **Total 442** | **488,115** | **34,397,640** | **5,480** | **89,072** | **7.05** |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | 444 - Public Street and Highway Lighting: | | | | | |
| 29 | 40 - General Service | | | | | |
| 30 | 41 - Municipal street lighting | 903 | 142,618 | 26 | 34,731 | 15.79 |
| 31 | 42 - Municipal traffic control signal light | 23 | 2,135 | 8 | 2,875 | 9.28 |
| 32 | **Public Street & Highway lighting billed** | **926** | **144,753** | **34** | **27,235** | **15.63** |
| 33 | Public St & Highway lighting-unbilled | (2) | (364) | | | |
| 34 | Bridger Depr & Boardman Decomm | | (590) | | | |
| 35 | **Total 444** | **924** | **143,799** | **34** | **27,176** | **15.56** |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | Total Billed | 688,246 | 54,485,056 | 18,937 | 36,344 | 7.92 |
| 42 | Total Unbilled Rev. (See Instr. 6) | (6,080) | (651,050) | | | |
| 43 | TOTAL | 682,166 | 53,834,006 | 18,937 | 36,344 | 7.92 |

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 | | | | | | | | | |

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 |
| | | | | 1,549,531 | | $ 1,549,531 | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
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| | | | | | | | 20 |
| | | | | | | | 21 |
| | | | | | | | 22 |
| | | | | | | | 23 |
| | | | | | | | 24 |
| | | | | | | | 25 |
| | | | | | | | 26 |

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 | | | | | |
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| 14 | | | | | |
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| 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 | $ 140,678 |
| 22 | | | |
| 23 | " | Transformer Rentals - Dist | 698 |
| 24 | | | |
| 25 | " | Line Rentals | - |
| 26 | | | |
| 27 | " | Cogeneration | 72,265 |
| 28 | | | |
| 29 | " | Pole Attachments | 106,910 |
| 30 | | | |
| 31 | " | Facilities Charges | 401,174 |
| 32 | | | |
| 33 | " | Other Rentals | 23,472 |
| 34 | | | |
| 35 | " | Water Lease | 2,876 |
| 36 | | | |
| 37 | " | | |
| 38 | Total Account 454 | | $ 748,075 |

## 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 | $ 82,769 |
| 7 | | |
| 8 | Account 456 | |
| 9 | | |
| 10 | Transmission for Others - Network | $ 491,448 |
| 11 | Transmission - Point-to-Point and Other | 1,298,564 |
| 12 | Photovoltaic Station Service | - |
| 13 | DSM Rider Funds | 2,154,604 |
| 14 | Sierra Pacific Usage Charge | 3,535 |
| 15 | Antelope | - |
| 16 | Miscellaneous | 2,778 |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | Total Account 456 | $ 3,950,930 |
| 21 | | |
| 22 | | |
| 23 | | |

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON

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

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| 1 | (1) POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | $ 41,682 | $ 50,046 |
| 5 | (501) Fuel | 5,008,233 | 6,424,516 |
| 6 | (502) Steam Expenses | 394,622 | 418,593 |
| 7 | (503) Steam from Other Sources | | |
| 8 | (Less) (504) Steam Transferred-Cr. | | |
| 9 | (505) Electric Expenses | 64,801 | 68,406 |
| 10 | (506) Miscellaneous Steam Power Expenses | 498,066 | 392,871 |
| 11 | (507) Rents | 14,009 | 8,928 |
| 12 | (509) Allowances | | |
| 13 | TOTAL Operation (Enter Total of lines 4 thru 12) | 6,021,413 | 7,363,361 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 2,352 | 4,323 |
| 16 | (511) Maintenance of Structures | 18,757 | 22,807 |
| 17 | (512) Maintenance of Boiler Plant | 512,057 | 665,523 |
| 18 | (513) Maintenance of Electric Plant | 201,055 | 240,324 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 252,773 | 277,915 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 986,994 | 1,210,893 |
| 21 | TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20) | 7,008,406 | 8,574,254 |
| 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 | 244,264 | 240,006 |
| 45 | (536) Water for Power | 249,442 | 372,651 |
| 46 | (537) Hydraulic Expenses | 639,182 | 612,487 |
| 47 | (538) Electric Expenses | 82,706 | 68,262 |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 352,240 | 233,169 |
| 49 | (540) Rents | 10,297 | 9,666 |
| 50 | TOTAL Operation (Enter Total of lines 44 thru 49) | 1,578,131 | 1,536,241 |

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 | $ 4,004 | $ 4,944 |
| 54 | (542) Maintenance of Structures | 48,512 | 46,035 |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 35,003 | 23,642 |
| 56 | (544) Maintenance of Electric Plant | 82,162 | 113,866 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 120,080 | 117,506 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 289,760 | 305,992 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58) | 1,867,892 | 1,842,234 |
| 61 | Operation | | |
| 62 | (546) Operation Supervision and Engineering | 29,297 | 26,567 |
| 63 | (547) Fuel | 1,760,883 | 2,507,960 |
| 64 | (548) Generation Expenses | 184,626 | 198,529 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 42,027 | 38,388 |
| 66 | (550) Rents | - | - |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 2,016,834 | 2,771,444 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | 10 | - |
| 70 | (552) Maintenance of Structures | 14,271 | 14,942 |
| 71 | (553) Maintenance of Generating and Electric Plant | 27,405 | 3,125 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 94,806 | 52,186 |
| 73 | TOTAL Maintenance (Enter Total of lines 69 thru 72) | 136,491 | 70,253 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73) | 2,153,325 | 2,841,698 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 11,333,025 | 9,919,405 |
| 77 | (556) System Control and Load Dispatching | 123 | 100 |
| 78 | (557) Other Expenses | 677,300 | 2,452,085 |
| 79 | TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78) | 12,010,448 | 12,371,590 |
| 80 | TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79) | 23,040,070 | 25,629,775 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 134,412 | 170,284 |
| 84 | (561) Load Dispatching | 208,180 | 120,729 |
| 85 | (562) Station Expenses | 123,203 | 108,395 |
| 86 | (563) Overhead Line Expenses | 45,669 | 39,841 |
| 87 | (564) Underground Line Expenses | | |
| 88 | (565) Transmission of Electricity by Others | 212,057 | 286,612 |
| 89 | (566) Miscellaneous Transmission Expenses | 1 | 97 |
| 90 | (567) Rents | 204,023 | 126,995 |
| 91 | TOTAL Operation (Enter Total of lines 83 thru 90) | 927,545 | 852,955 |
| 92 | Maintenance | | |
| 93 | (568) Maintenance Supervision and Engineering | 6,602 | 6,465 |
| 94 | (569) Maintenance of Structures | 41,119 | 38,324 |
| 95 | (570) Maintenance of Station Equipment | 82,132 | 135,275 |
| 96 | (571) Maintenance of Overhead Lines | 37,698 | 120,896 |
| 97 | (572) Maintenance of Underground Lines | | |
| 98 | (573) Maintenance of Miscellaneous Transmission Plant | 143 | - |
| 99 | TOTAL Maintenance (Enter Total of lines 93 thru 98) | 167,694 | 300,960 |
| 100 | TOTAL Transmission Expenses (Enter Total of lines 91 and 99) | 1,095,239 | 1,153,915 |
| 102 | Operation | | |
| 103 | (580) Operation Supervision and Engineering | 185,421 | 186,340 |

| Line No. | Account (a) | Amount for Current Year (b) | Amount for Previous Year (c) |
|---|---|---|---|
| | ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON | | |
| | If the amount for previous year is not derived from previously reported figures, explain in footnotes. | | |
| 104 | 3. DISTRIBUTION EXPENSES (Continued) | | |
| 105 | (581) Load Dispatching | $ 167,843 | $ 147,231 |
| 106 | (582) Station Expenses | 65,744 | 60,472 |
| 107 | (583) Overhead Line Expenses | 367,043 | 291,515 |
| 108 | (584) Underground Line Expenses | 51,462 | 39,148 |
| 109 | (585) Street Lighting and Signal System Expenses | 5,531 | 4,060 |
| 110 | (586) Meter Expenses | 167,166 | 163,022 |
| 111 | (587) Customer Installations Expenses | 95,901 | 59,638 |
| 112 | (588) Miscellaneous Distribution Expenses | 303,418 | 262,440 |
| 113 | (589) Rents | 16,800 | 11,385 |
| 114 | TOTAL Operation (Enter Total of lines 103 thru 113) | 1,426,329 | 1,225,252 |
| 115 | Maintenance | | |
| 116 | (590) Maintenance Supervision and Engineering | (72,428) | 462 |
| 117 | (591) Maintenance of Structures | - | - |
| 118 | (592) Maintenance of Station Equipment | 164,269 | 163,900 |
| 119 | (593) Maintenance of Overhead Lines | 1,031,632 | 1,043,477 |
| 120 | (594) Maintenance of Underground Lines | 10,650 | 8,190 |
| 121 | (595) Maintenance of Line Transformers | 960 | 1,383 |
| 122 | (596) Maintenance of Street Lighting and Signal Systems | 25,840 | 22,475 |
| 123 | (597) Maintenance of Meters | 33,498 | 26,251 |
| 124 | (598) Maintenance of Miscellaneous Distribution Plant | 18,066 | 22,027 |
| 125 | TOTAL Maintenance (Enter Total of lines 116 thru 124) | 1,212,487 | 1,288,164 |
| 126 | TOTAL Distribution Expenses (Enter Total of lines 114 and 125) | 2,638,816 | 2,513,415 |
| 127 | 4. CUSTOMER ACCOUNTS EXPENSES | | |
| 128 | Operation | | |
| 129 | (901) Supervision | 48,995 | 17,671 |
| 130 | (902) Meter Reading Expenses | 332,214 | 78,963 |
| 131 | (903) Customer Records and Collection Expenses | 496,503 | 555,097 |
| 132 | (904) Uncollectible Accounts | 401,264 | 191,185 |
| 133 | (905) Miscellaneous Customer Accounts Expenses | (54) | 16 |
| 134 | TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133) | 1,278,922 | 842,932 |
| 135 | 5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES | | |
| 136 | Operation | | |
| 137 | (907) Supervision | 43,062 | 48,872 |
| 138 | (908) Customer Assistance Expenses | 2,316,690 | 2,275,477 |
| 139 | (909) Informational and Instructional Expenses | 15,531 | 15,192 |
| 140 | (910) Miscellaneous Customer Service and Informational Expenses | 33,547 | 44,303 |
| 141 | TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140) | 2,408,830 | 2,383,844 |
| 142 | 6. SALES EXPENSES | | |
| 143 | Operation | | |
| 144 | (911) Supervision | | |
| 145 | (912) Demonstrating and Selling Expenses | - | 3639 |
| 146 | (913) Advertising Expenses | | |
| 147 | (916) Miscellaneous Sales Expenses | | |
| 148 | TOTAL Sales Expenses (Enter Total of lines 144 thru 147) | - | 3,639 |
| 149 | 7. ADMINISTRATIVE AND GENERAL EXPENSES | | |
| 150 | Operation | | |
| 151 | (920) Administrative and General Salaries | 3,706,766 | 3,255,870 |
| 152 | (921) Office Supplies and Expenses | 662,544 | 655,957 |
| 153 | (922) Administrative Expenses Transferred-Credit | (1,301,361) | (1,163,996) |

| Line No. | ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON<br>If the amount for previous year is not derived from previously reported figures, explain in footnotes.<br>Account<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 154 | 7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued) | | |
| 155 | (923) Outside Services Employed | $ 317,324 | $ 364,427 |
| 156 | (924) Property Insurance | 133,126 | 140,544 |
| 157 | (925) Injuries and Damages | 264,703 | 296,110 |
| 158 | (926) Employee Pensions and Benefits | 3,371,500 | 3,004,798 |
| 159 | (927) Franchise Requirements | - | - |
| 160 | (928) Regulatory Commission Expenses | 535,629 | 282,156 |
| 161 | (929) Duplicate Charges-Cr | | |
| 162 | (930.1) General Advertising Expenses | 17,081 | 27,544 |
| 163 | (930.2) Miscellaneous General Expenses | 166,705 | 242,637 |
| 164 | (931) Rents | (15) | 84 |
| 165 | TOTAL Operation (Enter Total of lines 151 thru 164) | 7,874,002 | 7,106,131 |
| 166 | Maintenance | | |
| 167 | (935) Maintenance of General Plant | 290,163 | 243,371 |
| 168 | TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167) | 8,164,165 | 7,349,501 |
| 169 | TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168) | $38,626,044 | $ 39,877,021 |

| Line No. | SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON<br>Functional Classification<br>(a) | Operation<br>(b) | Maintenance<br>(c) | Total<br>(d) |
|---|---|---|---|---|
| 170 | Power Production Expenses | | | |
| 171 | Electric Generation: | | | |
| 172 | Steam power | $ 6,021,413 | $ 986,994 | $ 7,008,406 |
| 173 | Nuclear power | | | |
| 174 | Hydraulic - Conventional | 1,578,131 | 289,760 | 1,867,892 |
| 175 | Hydraulic - Pumped Storage | | | |
| 176 | Other power | 2,016,834 | 136,491 | 2,153,325 |
| | Other Power Supply Expenses | 12,010,448 | - | 12,010,448 |
| 177 | Total Power Production Expenses | 21,626,825 | 1,413,245 | 23,040,070 |
| 178 | Transmission Expenses | 927,545 | 167,694 | 1,095,239 |
| 179 | Distribution Expenses | 1,426,329 | 1,212,487 | 2,638,816 |
| 180 | Customer Accounts Expenses | 1,278,922 | - | 1,278,922 |
| 181 | Customer Service and Informational Expenses | 2,408,830 | - | 2,408,830 |
| 182 | Sales Expenses | - | - | - |
| 183 | Administrative and General Expenses | 7,874,002 | 290,163 | 8,164,165 |
| 184 | Total Electric Operation and Maintenance Expenses | $ 35,542,454 | $ 3,083,590 | $ 38,626,044 |

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........................................................ | $ - | $ 267,292 | | $ 267,292 |
| 2 | Steam Production Plant........................................... | 1,928,459 | - | | 1,928,459 |
| 3 | Nuclear Production Plant......................................... | | | | - |
| 4 | Hydraulic Production Plant - Conventional............... | 662,316 | - | | 662,316 |
| 5 | Hydraulic Production Plant - Pumped Storage......... | | | | |
| 6 | Other Production Plant............................................ | 702,078 | - | | 702,078 |
| 7 | Transmission Plant.................................................. | 944,030 | - | | 944,030 |
| 8 | Distribution Plant..................................................... | 1,839,806 | - | | 1,839,806 |
| 9 | General Plant........................................................... | 606,725 | - | | 606,725 |
| 10 | Depreciation on Disallowed Costs............................ | (12,838) | - | | (12,838) |
| 11 | Boardman ARO Depreciation.................................. | 24,842 | | | 24,842 |
| 12 | ARO Accretion .......................................................... | 9,829 | | | 9,829 |
| 13 | TOTAL................................. | $ 6,705,246 | $ 267,292 | | $ 6,972,538 |

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 JOOA SWAP TRANS COST | | | $ 1,385.77 |
| Account 411 | | | |
| 411.6 | | | $ - |
| 411.7 | | | - |
| 411.8 - Green Tags and Emissions | | | (5,568) |
| | | | $ (4,182) |

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

| | KIND OF TAX | Amount |
|---|---|---|
| 1 | Federal Taxes: | |
| 2 | FICA | $ 730,363 |
| 3 | FUTA | 4,279 |
| 4 | Less: Payroll Deduction and Loading | (751,588) |
| 5 | State Taxes: | |
| 6 | Ad Valorem | 1,223,892 |
| 7 | Licenses - Hydro Projects | 195 |
| 8 | Regulatory Commission Fees | 254,808 |
| 9 | Franchise Taxes | 859,928 |
| 10 | State Unemployment Taxes | 16,946 |
| 11 | Hydro Generation KWH Tax | 79,330 |
| 12 | Canada Sales Tax | 0 |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |
| 21 | | |
| 22 | | |
| 23 | TOTAL (Must agree with page 1, line 12.) | 2,418,153 |

## 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 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 12 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 | $ 60,165,308 |
| 2 | Operations and Maintenance Expenses | 38,626,044 |
| 3 | Taxes Other Than Income | 2,418,153 |
| 4 | Regulatory Debits/Credits | 1,003,154 |
| 5 | State Income (Excise) Tax | 387,628 |
| 6 | Interest | 4,004,488 |
| 7 | Federal Income Tax Depreciation | 6,695,418 |
| 8 | Other Line items to Derive Taxable Income | 9,829 |
| 9 | Amortization of Limited-Term Plant | 263,110 |
| 10 | | |
| 11 | | |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | Federal Tax Net Income | $ 6,757,486 |
| 25 | | |
| 26 | | |
| 27 | Show Computation of Tax: | |
| 28 | | |
| 29 | Federal Income Tax @ 35% | $ 2,365,120 |
| 30 | FIN 48 Adjustment | - |
| 31 | Prior Years' Tax Adjustment | (151,205) |
| 32 | Total Federal Income Tax Before Other Adjustments | 2,213,915 |
| 33 | | |
| 34 | Other Tax Adjustments | |
| 35 | Allowance for AFUDC | $ 1,269,496 |
| 36 | Income Tax Adjustments | (4,081,266) |
| 37 | Federal Tax on Other Tax Adj @ 35% | (984,119) |
| 38 | | |
| 39 | Total Federal Income Tax | $ 1,229,795 |

## 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 15 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 | $ 60,165,308 |
| 2 | Operations and Maintenance Expenses | 38,626,044 |
| 3 | Taxes Other Than Income | 2,418,153 |
| 4 | Regulatory Debits/Credits | 1,003,154 |
| 5 | Interest | 4,004,488 |
| 6 | State Income (Excise) Tax Depreciation | 6,695,418 |
| 7 | | |
| 8 | Other Line Items to Derive Taxable Income | |
| 9 | Amortization of Limited-Term Plant | 263,110 |
| | ARO Accretion Expense | 9,829 |
| 10 | Income Tax Adjustments | 4,118,064 |
| 11 | Allowance for AFUDC | (1,269,496) |
| 12 | IERCO Taxable Income | (840,206) |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |
| 21 | TOTAL Utility Operating Expenses (Enter lines 4 thru 20) | |
| 22 | | |
| 13 | | |
| 14 | State Tax Net Income | $ 5,136,752 |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | Show Computation of Tax: | |
| 20 | | |
| 21 | State Taxes | 387,628 |
| 22 | Add: FIN 48 Adjustment | - |
| 23 | Prior Period Adjustment | (53,266) |
| 24 | | |
| 25 | | |
| 26 | Total Oregon State Tax | $ 334,362 |

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 | | 33,722 | (18,819) |
| 4 | Other Operating (See Note 1) | | 537,979 | (438,335) |
| 5 | | | | |
| 6 | Non-Operating | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | Total Electric | $ | $ 571,700 | $ (457,154) |
| 10 | Gas | $ | $ | $ |
| 11 | | | | |
| 12 | | | | |
| 13 | Other | | | |
| 14 | Total Gas | $ | $ | $ |
| 15 | Other Non-Electric | $ | $ | $ |
| 16 | Total (Account 190) | $ | $ 571,700 | $ (457,154) |
| 17 | Classification of TOTALS | | | |
| 18 | Federal Income Tax | $ | $ | $ |
| 19 | State Income Tax | $ | $ | $ |
| 20 | Local Income Tax | $ | $ | $ |
| | Note 1: | | | |
| | Rate Case Disallowance | | 28,533 | 0 |
| | Executive Deferred Compensation | | 518 | (128) |
| | Executive Deferred Compensation Long-Term | | 0 | 0 |
| | SFAS 112 - Post Retirement Benefits | | 7,846 | (3,219) |
| | Non-VEBA Pension and Benefits | | 6,395 | (4,291) |
| | FAS 123R - Stock Based Compensation | | 57,723 | (34,479) |
| | Provision for Rate Refunds | | 0 | 0 |
| | Revenue Sharing | | 0 | 0 |
| | Montana NOL | | 0 | 0 |
| | Oregon NOL | | 0 | 0 |
| | Federal NOL | | 0 | 0 |
| | Valmy Union Pacific Contract | | 0 | 0 |
| | Deferred Idaho ITC | | (168,984) | (97,213) |
| | VEBA - Post Retiree Benefits | | 147,379 | (8,698) |
| | Bridger Revenue Deferral | | 6,782 | (4,453) |
| | AFUDC Hells Canyon Relicensing | | 559,157 | (229,044) |
| | Reg Liability | | 0 | 0 |
| | Reg Asset | | 0 | 0 |
| | Boardman Decommission | | 0 | 0 |
| | USBR-American Falls O&M Costs Settlement | | 1,820 | 0 |
| | Oregon Pension Expense | | 48,832 | (20,041) |
| | Incentive Deferral - Profit Sharing not in rates | | 67,682 | (25,416) |
| | OR Reconnect Fees Adv | | 4 | (13) |
| | Asset Retirement Obligation (ARO) | | 22,131 | (10,982) |
| | Deferred GBC Federal | | (248,226) | 0 |
| | Retention Pay Accrual | | 386 | (359) |
| | Total | $ | $ 537,979 | $ (438,335) |

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 | | | | | |
|---|---|---|---|---|---|---|---|
| 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) | Balance at End of Year (k) | Line No. |
| | | | | | | | 1 |
| $ | $ | | $ | | $ | $ | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| 319,943 | (44,394) | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| $ 319,943 | $ (44,394) | | $ | | $ | $ | 9 |
| $ | $ | | $ | | $ | $ | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| $ | $ | | $ | | $ | $ | 14 |
| $ - | | | $ | | $ | $ | 15 |
| $ 319,943 | $ (44,394) | | $ | | $ | $ | 16 |
| | | | | | | | 17 |
| $ | $ | | $ | | $ | $ | 18 |
| $ | $ | | $ | | $ | $ | 19 |
| $ | $ | | $ | | $ | $ | 20 |

| | |
|---|---|
| $ - | $ - |

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. In the space provided furnish explanations, including the following in columnar order:
(a) State each certification number with a brief description of property.
(b) Total and amortizable cost of such property.
(c) Date amortization for tax purposes commenced.

| Line No. | Account (a) | Balance at Beginning of Year (b) | CHANGES DURING YEAR Amounts Debited (Account 410.1) (c) | Amounts Credited (Account 411.1) (d) |
|---|---|---|---|---|
| 1 | Accelerated Amortization (Account 281) | NONE | | |
| 2 | Electric | | | |
| 3 | Defense Facilities | | | |
| 4 | Pollution Control Facilities | | | |
| 5 | Other: Accelerated Amortization | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | TOTAL Electric (Enter Total of lines 3 thru 7) | | | |
| 9 | Gas | | | |
| 10 | Defense Facilities | | | |
| 11 | Pollution Control Facilities | | | |
| 12 | Other | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Gas (Enter Total of lines 10 thru 14) | | | |
| 16 | Other (Specify) | | | |
| 17 | TOTAL (Account 281)(Enter Total of 8, 15, and 16) | | $ - | $ - |
| 18 | | | | |
| 19 | Federal Income Tax | | | |
| 20 | State Income Tax | | | |
| 21 | Local Income Tax | | | |

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

(d) "Normal" depreciation rate used in computing the deferred tax.
(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| Amounts Debited (Account 410.2) | Amounts Credited (Account 411.2) | Debits | | Credits | | | |
| | | Acct. No. | Amount | Acct. No. | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
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| | | | | | | | 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 | | $ 95,589 | $ (138,399) |
| 3 | Gas | | | |
| 4 | Other (Define) | | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | | 95,589 | (138,399) |
| 6 | Other (Specify) | | | |
| 7 | FERC Jurisdictional Deferral | | | |
| 8 | Non-Utility Property | | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru 8) | | $ 95,589 | $ (138,399) |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | | | |
| 12 | State Income Tax | | | |
| 13 | Local Income Tax | | | |

| | | | |
|---|---|---|---|
| **Line 2:** | | | |
| Depr Federal Adj | | 250,250 | (44,095) |
| Intangible Asset - Labor Deductions | | (279,888) | - |
| N Valmy Partnership Capitalized Items | | 0 | - |
| CIAC as Taxable Income | | 93,990 | (88,610) |
| FERC Juris-S Georgia-Acct 282 Def only | | 0 | - |
| Engineering Fees | | 11,961 | (5,695) |
| Software Costs | | 19,276 | - |
| Total | | 95,589 | (138,399) |

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 | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| Amounts Debited (Account 410.2) | Amounts Credited (Account 411.2) | Debits | | Credits | | | |
| | | Acct. No. | Amount | Acct. No. | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 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) | | 1,305,061 | (2,297,284) |
| 3 | | | | |
| 4 | Total Electric........ | | 1,305,061 | (2,297,284) |
| 5 | | | | |
| 6 | | | | |
| 7 | Other (See Note 2)........ | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | Total (Account 283) (Enter Total of lines 4 - 9).... | | $ 1,305,061 | $ (2,297,284) |
| 11 | Classification of Total: | | | |
| 12 | Federal Income Tax........ | | | |
| 13 | State Income Tax........ | | | |
| 14 | Local Income Tax........ | | | |
| | **Note 1:** | | | |
| | Oregon PCAM........ | | 3,640 | (19,681) |
| | Langley Revenue Accrual........ | | 13,444 | (42,490) |
| | PCA ........ | | 249,718 | (993,940) |
| | Conservation Programs........ | | 3,179 | (35,115) |
| | Oregon Excess Power Supply Costs........ | | 2,304 | 0 |
| | OATT Revenue Deficiency ........ | | 0 | 0 |
| | Emission Allowances........ | | 0 | (71) |
| | Fixed Cost Adjustment (FCA)........ | | 63,497 | (396,913) |
| | OPUC Grid West Loans........ | | 0 | 0 |
| | Intervenor Funding Orders........ | | 0 | (2,997) |
| | Bonus Deferral........ | | 0 | 0 |
| | Prepaid Credit Facility........ | | 0 | (4,575) |
| | EIM Deferral........ | | 11,229 | (3,768) |
| | REC Sales........ | | 30,317 | (27,679) |
| | Pension Expense........ | | 327,392 | (549,479) |
| | Valmy Settlement Adjust........ | | 598,245 | (200,736) |
| | Bennett Mtn Maintenance Deferral........ | | 0 | 0 |
| | Custom Efficiency Incentive Payment........ | | 0 | 0 |
| | LIDAR Surveys Deferral........ | | 0 | (1,626) |
| | Reg Asset........ | | 0 | 0 |
| | Siemens LTP Contract........ | | 1,153 | (830) |
| | Siemens OR DRB Interest Reserve........ | | 161 | (480) |
| | Boardman Decommission........ | | 474 | (6,789) |
| | Boardman Removal........ | | 308 | (103) |
| | PS&I Costs........ | | 0 | (5,585) |
| | Royalty Income........ | | 0 | (4,427) |
| | Total........ | | 1,305,061 | (2,297,284) |
| | **Note 2:** | | | |
| | Advance Coal Royalties........ | | | |
| | Unrealized Gain/Loss from Rabbi Trust........ | | | |
| | Oregon Non-Operating Property Tax Adj........ | | | |
| | Unrealized Gain/Loss from SMSP........ | | | |
| | 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 |
| 3,362 | (85) | | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| $ 3,362 | $ (85) | | $ - | | $ - | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |

| | |
|---|---|
| 0 | 0 |
| 0 | 0 |
| 82 | (80) |
| 0 | (5) |
| 3,279 | 0 |
| 3,362 | (85) |

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 | $ 452,455 | 411.4 | $ (132,703) | | | |
| 10 | | | | | | | | | |
| 11 | Other (List separately | | | | | | | | |
| 12 | and show 3%, 4%, 7%, | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
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| 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)........................................ | $ 519,317,723 | $ 519,317,723 | | | | |
| 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).......................... | $ 519,317,723 | $ 519,317,723 | | | | |
| 9 | Leased to Others....................................................... | | | | | | |
| 10 | Held for Future Use.................................................... | $ 89,977 | $ 89,977 | | | | |
| 11 | Construction Work in Progress.................................... | $ 48,797,325 | $ 48,797,325 | | | | |
| 12 | Acquisition Adjustments............................................. | 100,845 | $ 100,845 | | | | |
| 13 | TOTAL Utility Plant (Enter Total of lines 8 thru 12)...... | $ 568,305,871 | $ 568,305,871 | | | | |
| 14 | Accum. Prov. for Depr., Amort., & Depl....................... | NOT AVAILABLE | | | | | |
| 15 | Net Utility Plant (Enter Total of line 13 less 14)………… | $ 568,305,871 | $ 568,305,871 | | | | |
| 16 | DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION | | | | | | |
| 17 | In Service | | | | | | |
| 18 | Depreciation.............................................................. | | | | | | |
| 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 2 | | | | | | |
| 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 li 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 | 12,627,358 | (19,872) | | | | 12,607,486 | (311) | 9 |
| 10 | (312) Boiler Plant Equipment | 43,721,658 | 61,421 | | | | 43,783,079 | (312) | 10 |
| 11 | (313) Engines and Engine Driven Generators | 0 | | | | | 0 | (313) | 11 |
| 12 | (314) Turbogenerator Units | 13,569,621 | | | | | 13,569,621 | (314) | 12 |
| 13 | (315) Accessory Electric Equipment | 4,606,593 | 31,092 | | | | 4,637,686 | (315) | 13 |
| 14 | (316) Misc. Power Plant Equipment | 1,796,953 | 23,434 | | | | 1,820,386 | (316) | 14 |
| 15 | (317) Asset Retirement Costs for Steam Production | 5,380,764 | (334,756) | | | | 5,046,008 | (317) | 15 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 81,809,557 | (238,682) | 0 | 0 | 0 | 81,570,875 | | 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 | 11,190,603 | 1,125 | | | | 11,191,728 | (330) | 27 |
| 28 | (331) Structures and Improvements | 20,852,172 | 5,125,170 | | | | 25,977,341 | (331) | 28 |
| 29 | (332) Reservoirs, Dams, and Waterways | 92,100,125 | | | | | 92,100,125 | (332) | 29 |
| 30 | (333) Water Wheels, Turbines, and Generators | 24,229,566 | 202,953 | (4,326) | | | 24,428,194 | (333) | 30 |
| 31 | (334) Accessory Electric Equipment | 12,315,628 | 157,163 | | | | 12,472,792 | (334) | 31 |
| 32 | (335) Misc. Power Plant Equipment | 4,749,827 | 1,020,463 | | | | 5,770,290 | (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) | 166,826,027 | 6,506,874 | (4,326) | | 0 | 173,328,576 | | 35 |

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

| Line No. | Account (a) | Balance at Beginning of year (b) | Additions (c) | Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| 36 | D. Other Production Plant | | | | | | | | 36 |
| 37 | (340) Land and Land Rights | $ | $ | $ | $ | $ | $ | (340) | 37 |
| 38 | (341) Structures and Improvements | 0 | | | | | 0 | (341) | 38 |
| 39 | (342) Fuel Holders, Products and Accessories | 0 | | | | | 0 | (342) | 39 |
| 40 | (343) Prime Movers | 0 | | | | | 0 | (343) | 40 |
| 41 | (344) Generators | 0 | | | | | 0 | (344) | 41 |
| 42 | (345) Accessory Electric Equipment | 0 | | | | | 0 | (345) | 42 |
| 43 | (346) Misc. Power Plant Equipment | 0 | | | | | 0 | (346) | 43 |
| 44 | (347) Asset Retirement Costs for Hydraulic Production | 0 | | | | | 0 | (347) | 44 |
| 45 | TOTAL Other Production Plant (Enter Total of lines 36 thru 44) | 0 | 0 | 0 | 0 | 0 | 0 | | 45 |
| 46 | TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45) | 248,635,584 | 6,268,193 | (4,326) | 0 | 0 | 254,899,451 | | 46 |
| 47 | 3. TRANSMISSION PLANT | | | | | | | | 47 |
| 48 | (350) Land and Land Rights | 4,770,300 | $ 71,664 | | | | 4,841,964 | (350) | 48 |
| 49 | (352) Structures and Improvements | 7,377,577 | 19,764 | (31) | | | 7,397,310 | (352) | 49 |
| 50 | (353) Station Equipment | 37,351,288 | 5,192,051 | (406,032) | | | 42,137,308 | (353) | 50 |
| 51 | (354) Towers and Fixtures | 25,736,248 | 922,858 | | | | 26,659,106 | (354) | 51 |
| 52 | (355) Poles and Fixtures | 34,710,235 | 567,110 | (508,513) | | | 34,768,831 | (355) | 52 |
| 53 | (356) Overhead Conductors and Devices | 29,276,876 | 495,018 | (454,132) | | | 29,317,762 | (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 | 48,567 | | | | | 48,567 | (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) | 139,271,091 | 7,268,465 | (1,368,708) | 0 | 0 | 145,170,848 | | 58 |
| 59 | 4. DISTRIBUTION PLANT | | | | | | | | 59 |
| 60 | (360) Land and Land Rights | 157,780 | $ 37,922 | | | | 195,702 | (360) | 60 |
| 61 | (361) Structures and Improvements | 1,866,978 | (138,116) | (8,279) | | | 1,720,583 | (361) | 61 |
| 62 | (362) Station Equipment | 8,344,724 | 2,321,969 | (166,626) | | 38,819 | 10,538,885 | (362) | 62 |
| 63 | (363) Storage Battery Equipment | 0 | 0 | | | | 0 | (363) | 63 |
| 64 | (364) Poles, Towers, and Fixtures | 19,545,721 | 1,455,969 | (233,195) | | | 20,768,495 | (364) | 64 |
| 65 | (365) Overhead Conductors and Devices | 8,875,388 | 551,251 | (225,366) | | | 9,201,274 | (365) | 65 |
| 66 | (366) Underground Conduit | 683,071 | 16,392 | 5,662 | | | 705,125 | (366) | 66 |
| 67 | (367) Underground Conductors and Devices | 3,392,229 | 376,970 | (72,004) | | | 3,697,195 | (367) | 67 |
| 68 | (368) Line Transformers | 48,718,172 | 1,691,188 | (60,587) | | | 50,348,773 | (368) | 68 |
| 69 | (369) Services | 2,874,370 | 35,999 | (20,783) | | | 2,889,586 | (369) | 69 |
| 70 | (370) Meters | 7,923,068 | 264,392 | (94,279) | | | 8,093,181 | (370) | 70 |
| 71 | (371) Installations on Customer Premises | 228,022 | 4,585 | (2,893) | | | 229,714 | (371) | 71 |
| 72 | (372) Leased Property on Customer Premises | 0 | | | | | 0 | (372) | 72 |
| 73 | (373) Street Lighting and Signal Systems | 208,837 | 3,919 | (1,766) | | | 210,991 | (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 ) | 102,818,361 | 6,622,440 | (880,116) | 0 | 38,819 | 108,599,503 | | 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 | 32,433 | | | | 528,331 | (390) | 78 |
| 79 | (391) Office Furniture and Equipment | 213,009 | (77,677) | | | | 135,332 | (391) | 79 |
| 80 | (392) Transportation Equipment | 2,939,057 | 301,306 | (68,233) | | | 3,172,130 | (392) | 80 |
| 81 | (393) Stores Equipment | 0 | | | | | 0 | (393) | 81 |
| 82 | (394) Tools, Shop and Garage Equipment | 4,129 | | | | | 4,129 | (394) | 82 |
| 83 | (395) Laboratory Equipment | 53,332 | | | | | 53,332 | (395) | 83 |
| 84 | (396) Power Operated Equipment | 1,941,023 | 157,339 | | | | 2,098,362 | (396) | 84 |
| 85 | (397) Communication Equipment | 4,679,424 | 5,740 | (284,498) | | | 4,400,666 | (397) | 85 |
| 86 | (398) Miscellaneous Equipment | 24,321 | (19,177) | | | | 5,144 | (398) | 86 |
| 87 | SUBTOTAL (Enter Total of lines 77 thru 86) | 10,358,435 | 399,964 | (352,731) | 0 | 0 | 10,405,669 | | 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) | 10,358,435 | 399,964 | (352,731) | 0 | 0 | 10,405,669 | | 91 |
| 92 | TOTAL (Accounts 101 and 106) | 501,325,723 | 20,559,062 | (2,605,881) | 0 | 38,819 | 519,317,723 | | 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 | 501,325,723 | 20,559,062 | (2,605,881) | - | 38,819 | 519,317,723 | | 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 1 | | | | |
| 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)........ | $ 254,294,179 | $ 254,294,179 | | | | |
| 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)........ | 254,294,179 | 254,294,179 | | | | |
| 9 | Leased to Others........ | | | | | | |
| 10 | Held for Future Use........ | $ 329,726 | 329,726 | | | | |
| 11 | Construction Work in Progress........ | | | | | | |
| 12 | Acquisition Adjustments........ | | | | | | |
| 13 | TOTAL Utility Plant (Enter Total of lines 8 thru 12)........ | 254,623,905 | 254,623,905 | | | | |
| 14 | Accum. Prov. for Depr., Amort., & Depl........ | $ 100,392,482 | 100,392,482 | | | | |
| 15 | Net Utility Plant (Enter Total of line 13 less 14)........ | $ 154,231,423 | $ 154,231,423 | | | | |
| 16 | DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION | | | | | | |
| 17 | In Service | | | | | | |
| 18 | Depreciation........ | $ 99,241,762 | $ 99,241,762 | | | | |
| 19 | Rights…………………….. | | 0 | | | | |
| 20 | Amort. of Underground Storage Land and Land Rights........ | | | | | | |
| 21 | Amort. of Other Utility Plant........ | $ 1,150,720 | 1,150,720 | | | | |
| 22 | TOTAL In Service (Enter total of lines 18 thru 21)........ | 100,392,482 | 100,392,482 | | | | |
| 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)..... | $ 100,392,482 | $ 100,392,482 | | | | |

| 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.)<br><br>1. Report below the original cost of electric plant in service according to prescribed accounts.<br><br>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.<br><br>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.......... | $ 239 | | | | | $ 246 | (301) | 2 |
| 3 | (302) Franchises and Consents.......... | 1,222,664 | | | | | 1,306,168 | (302) | 3 |
| 4 | (303) Miscellaneous Intangible Plant.......... | 1,192,103 | | | | | 1,146,257 | (303) | 4 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4).......... | $ 2,415,005 | | | | | $ 2,452,671 | | 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).... | $ 44,732,000 | | | | | $ 50,152,765 | | 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 | 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.)<br><br>1. Report below the original cost of electric plant in service according to prescribed accounts.<br><br>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.<br><br>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 3 | $ 32,087,497 | | | | | $ 36,665,640 | | 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). | $ 22,122,237 | | | | | $ 23,231,768 | | 45 |
| 46 | TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45 | 98,941,734 | | | | | 110,050,173 | | 46 |
| 47 | 3. TRANSMISSION PLANT | | | | | | | | 47 |
| 48 | (350) Land and Land Rights............................................................ | 1,494,619 | | | | | 1,581,193 | (350) | 48 |
| 49 | (352) Structures and Improvements................................................ | 3,196,200 | | | | | 3,418,917 | (352) | 49 |
| 50 | (353) Station Equipment.................................................................. | 16,778,095 | | | | | 18,299,957 | (353) | 50 |
| 51 | (354) Towers and Fixtures................................................................ | 7,585,368 | | | | | 8,796,719 | (354) | 51 |
| 52 | (355) Poles and Fixtures.................................................................. | 6,539,437 | | | | | 7,840,346 | (355) | 52 |
| 53 | (356) Overhead Conductors and Devices........................................ | 8,730,233 | | | | | 9,675,574 | (356) | 53 |
| 54 | (357) Underground Conduit............................................................. | | | | | | | (357) | 54 |
| 55 | (358) Underground Conductors and Devices.................................. | | | | | | | (358) | 55 |
| 56 | (359) Roads and Trails..................................................................... | 16,034 | | | | | 16,621 | (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)....... | $ 44,339,986 | | | | | $ 49,629,327 | | 58 |
| 59 | 4. DISTRIBUTION PLANT | | | | | | | | 59 |
| 60 | (360) Land and Land Rights............................................................ | 124,389 | | | | | 171,440 | (360) | 60 |
| 61 | (361) Structures and Improvements................................................ | 1,530,958 | | | | | 1,807,901 | (361) | 61 |
| 62 | (362) Station Equipment.................................................................. | 9,789,607 | | | | | 10,029,500 | (362) | 62 |
| 63 | (363) Storage Battery Equipment..................................................... | 0 | | | | | 0 | (363) | 63 |
| 64 | (364) Poles, Towers, and Fixtures.................................................... | 18,842,485 | | | | | 20,768,495 | (364) | 64 |
| 65 | (365) Overhead Conductors and Devices........................................ | 8,804,153 | | | | | 9,201,274 | (365) | 65 |
| 66 | (366) Underground Conduit............................................................. | 650,604 | | | | | 705,125 | (366) | 66 |
| 67 | (367) Underground Conductors and Devices.................................. | 3,122,355 | | | | | 3,697,195 | (367) | 67 |
| 68 | (368) Line Transformers.................................................................. | 19,480,444 | | | | | 22,558,234 | (368) | 68 |
| 69 | (369) Services.................................................................................. | 2,871,692 | | | | | 2,889,586 | (369) | 69 |
| 70 | (370) Meters..................................................................................... | 2,913,941 | | | | | 3,068,036 | (370) | 70 |
| 71 | (371) Installations on Customer Premises....................................... | 224,697 | | | | | 229,714 | (371) | 71 |

## ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

## ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

| Line No. | Account (a) | Balance at Beginning of Year (b) | Additions (c) | Retirements (d) | Adjustments (e) | Transfers (f) | Balance at End of Year (g) | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| 72 | (372) Leased Property on Customer Premises................................ | | | | | | | (372) | 72 |
| 73 | (373) Street Lighting and Signal Systems........................................ | 209,733 | | | | | 210,991 | (373) | 73 |
| 74 | (374) Asset Retirement Costs for Distribution Plant........................ | | | | | | | (374) | 74 |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74)........... | $ 68,565,058 | | | | | $ 75,337,491 | | 75 |
| 76 | 5. GENERAL PLANT | | | | | | | | 76 |
| 77 | (389) Land and Land Rights............................................................ | 693,603 | | | | | 751,976 | (389) | 77 |
| 78 | (390) Structures and Improvements................................................ | 4,640,784 | | | | | 5,195,958 | (390) | 78 |
| 79 | (391) Office Furniture and Equipment............................................. | 1,953,469 | | | | | 1,934,154 | (391) | 79 |
| 80 | (392) Transportation Equipment...................................................... | 3,174,564 | | | | | 3,796,124 | (392) | 80 |
| 81 | (393) Stores Equipment.................................................................. | 94,360 | | | | | 126,940 | (393) | 81 |
| 82 | (394) Tools, Shop, and Garage Equipment..................................... | 335,600 | | | | | 449,519 | (394) | 82 |
| 83 | (395) Laboratory Equipment............................................................ | 531,493 | | | | | 597,270 | (395) | 83 |
| 84 | (396) Power Operated Equipment................................................... | 630,991 | | | | | 700,463 | (396) | 84 |
| 85 | (397) Communication Equipment.................................................... | 2,318,420 | | | | | 2,331,351 | (397) | 85 |
| 86 | (398) Miscellaneous Equipment...................................................... | 249,672 | | | | | 300,554 | (398) | 86 |
| 87 | SUBTOTAL (Enter Total of lines 77 thru 86)............................... | 14,622,957 | | | | | 16,184,308 | | 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)......... | 14,622,957 | | | | | 16,184,308 | | 90 |
| 91 | TOTAL (Accounts 101 and 106)............................................ | 228,884,742 | | | | | 253,653,970 | | 91 |
| 92 | (102) Electric Plant Purchased **................................................... | | | | | | | | 92 |
| 93 | (Less) (102) Electric Plant Sold **.................................................... | | | | | | | | 93 |
| 94 | Asset Retirement Obligations (ARO)................................................ | 579,057 | | | | | 640,209 | | 94 |
| 95 | TOTAL Electric Plant in Service................................................... | $ 229,463,798 | | | | | $ 254,294,179 | | 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 | 6,695,418 | 6,695,418 | | |
| 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) | 6,695,418 | 6,695,418 | | |
| 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) | $ 6,695,418 | $ 6,695,418 | | |

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 | $ 25,900,912 | $ 25,900,912 | | |
| 19 | Nuclear Production | | | | |
| 20 | Hydraulic Production - Conventional | 18,095,358 | 18,095,358 | | |
| 21 | Hydraulic Production - Pumped Storage | | | | |
| 22 | Other Production | 4,499,737 | 4,499,737 | | |
| 23 | Transmission | 15,543,836 | 15,543,836 | | |
| 24 | Distribution | 29,821,567 | 29,821,567 | | |
| 25 | General | 4,763,799 | 4,763,799 | | |
| 26 | FAS 143 Adj &/or Disallowed Cost | 616,552 | 616,552 | | |
| 27 | TOTAL (Enter Total of lines 18 thru 26) | $ 99,241,762 | $ 99,241,762 | | |

## 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) | $ 2,821,708 | $ 2,629,057 | |
| 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) | 714,250 | 764,317 | |
| 8 | Transmission Plant (Estimated) | 460,708 | 427,157 | |
| 9 | Distribution Plant (Estimated) | 953,899 | 1,082,032 | |
| 10 | Assigned to - Other | 79,973 | 57,637 | |
| 11 | TOTAL Account 154 (Enter Total of lines 5 thru 10) | 2,208,831 | 2,331,142 | |
| 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) | 187,342 | 81,315 | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | $ 5,217,881 | $ 5,041,515 | |

## 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 | **INFORMATION** |
| 7 | Other.......................................................... | | | (Excluding Station Use): | |
| 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 purchases 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 cases 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 amounts 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 | 126.01 | Friday | 6 | 9 A.M | 60 Min. Int | 67,776 |
| 34 | February | 92.19 | Thursday | 2 | 7 P.M. | " " " | 55,010 |
| 35 | March | 104.68 | Thursday | 2 | 8 A.M. | " " " | 56,950 |
| 36 | April | 88.38 | Tuesday | 4 | 8 A.M. | " " " | 51,193 |
| 37 | May | 97.50 | Tuesday | 30 | 6 P.M. | " " " | 56,049 |
| 38 | June | 113.40 | Monday | 26 | 4 P.M. | " " " | 63,738 |
| 39 | July | 120.88 | Friday | 7 | 5 P.M. | " " " | 76,768 |
| 40 | August | 122.26 | Wednesday | 2 | 6 P.M. | " " " | 76,009 |
| 41 | September | 113.81 | Friday | 1 | 6 P.M. | " " " | 57,013 |
| 42 | October | 85.37 | Monday | 16 | 8 A.M. | " " " | 54,683 |
| 43 | November | 79.12 | Thursday | 30 | 8 A.M. | " " " | 54,425 |
| 44 | December | 105.09 | Wednesday | 13 | 7 P.M. | " " " | 62,796 |
| 45 | TOTAL | 1,248.69 | | | | | 732,410 |

## 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 | $ 515,878 | $ 24,181 | $ 491,697 |
| 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 | 1,665,574 | 78,072 | 1,587,502 |
| 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 | 90,843 | 4,258 | 86,585 |
| 10 | of items so grouped is shown) | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | Directors' fees and expenses (see detail on page 39) | 889,121 | 41,677 | 847,444 |
| 14 | | | | |
| 15 | Memberships and contributions (see detail on page 39) | 395,025 | 18,516 | 376,509 |
| 16 | | | | |
| 17 | | | | |
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| 37 | | | | |
| 38 | | | | |
| 39 | **TOTAL** | $ 3,556,440 | $ 166,704 | $ 3,389,736 |

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 | | | | |
| 2 | Directors' Fees and Expenses: | | | |
| 3 | Anette ELG | $ 66,907 | 3,136 | 63,771 |
| 4 | Christine King-Fees and expenses.............................................. | 87,961 | 4,123 | 83,838 |
| 5 | Richard Navarro - Fees and expenses.......................................... | 76,230 | 3,573 | 72,657 |
| 6 | Dennis Johnson - Fees and expenses……………………………...... | 70,290 | 3,295 | 66,995 |
| 7 | J LaMont Keen - Fees and expenses............................................ | 64,350 | 3,016 | 61,334 |
| 8 | Judith Johansen-Fees and expenses........................................... | 78,358 | 3,673 | 74,685 |
| 9 | Richard Dahl - Fees..................................................................... | 91,575 | 4,292 | 87,282 |
| 10 | Robert A Tinstman Fees and expenses........................................ | 170,703 | 8,002 | 162,702 |
| 11 | Ronald Jibson - Fees and expenses………………………............ | 72,359 | 3,392 | 68,968 |
| 12 | Thomas Carlile - Fees and expenses............................................ | 76,230 | 3,573 | 72,657 |
| 13 | Director Travel and Lodging.......................................................... | 34,158 | 1,601 | 32,557 |
| 14 | SUBTOTAL............................... | 889,121 | 41,677 | 847,446 |
| 15 | | | | |
| 16 | Other Expenses >$5,000: | | | |
| 17 | Bank of New York......................................................................... | $ 12,925 | 606 | 12,319 |
| 18 | Investis, Inc.................................................................................. | 37,457 | 1,756 | 35,701 |
| 19 | Payroll Related Expenses............................................................. | 16,651 | 780 | 15,871 |
| 20 | Miscellaneious <$5,000................................................................ | 23,810 | 1,116 | 22,694 |
| 21 | SUBTOTAL............................... | 90,843 | 4,258 | 86,585 |
| 22 | Miscellaneous General Management Expenses: | | | |
| 23 | American Stock Transfers & Trust | 60,407 | 2,832 | 57,575 |
| 24 | Bloomberg Finance LP | 22,597 | 1,059 | 21,538 |
| 25 | Broadridge Financial Solutions | 50,438 | 2,364 | 48,073 |
| 26 | Deutsche Bank Trust Co | 30,000 | 1,406 | 28,594 |
| 27 | E Source | 27,743 | 1,300 | 26,443 |
| 28 | Market Intelligence | 20,691 | 970 | 19,721 |
| 29 | Moody's Analystics Inc | 35,590 | 1,668 | 33,922 |
| 30 | NASDAQ Corporate Solutions LLC | 51,157 | 2,398 | 48,759 |
| 31 | New York Stock Exchange I | 58,929 | 2,762 | 56,166 |
| 32 | Payroll Related Expenses | 168,067 | 7,878 | 160,189 |
| 33 | PR Newswire | 16,575 | 777 | 15,798 |
| 34 | Rivel Research Group | 15,840 | 742 | 15,098 |
| 35 | Stock Based Compensation | 989,313 | 46,373 | 942,940 |
| 36 | Wells Fargo Shareowner Services……………………………......... | 118,227 | 5,542 | 112,685 |
| 37 | SUBTOTAL............................... | 1,665,574 | 78,072 | 1,587,501 |
| 38 | | | | |
| 39 | Memberships and Contributions: | | | |
| 40 | Arizona State University | 41,666 | 1,953 | 39,713 |
| 41 | Associated Taxpayers of Idaho - Membership............................... | 26,000 | 1,219 | 24,781 |
| 42 | Association of Idaho Cities............................................................ | 5,000 | 234 | 4,766 |
| 43 | Boise Valley Eco.......................................................................... | 20,000 | 937 | 19,063 |
| 44 | Business Plus.............................................................................. | 5,000 | 234 | 4,766 |
| 45 | Chambers of Commerce............................................................... | 85,547 | 4,010 | 81,537 |
| 46 | Chartwell Inc................................................................................ | 34,888 | 1,635 | 33,253 |
| 47 | Idaho Association of Commerce and Industry............................... | 15,000 | 703 | 14,297 |
| 48 | Idaho Mining Association.............................................................. | 6,500 | 305 | 6,195 |
| 49 | National Association of Directors.................................................. | 8,075 | 379 | 7,696 |
| 50 | National Hydropower Association.................................................. | 36,935 | 1,731 | 35,204 |
| 51 | Pacific NW Utilities....................................................................... | 42,747 | 2,004 | 40,743 |
| 52 | S&P Global.................................................................................. | 29,261 | 1,372 | 27,889 |
| 53 | Western Energy Institute | 30,962 | 1,451 | 29,511 |
| 54 | Misc Memberships under $2,000.................................................. | 7,444 | 349 | 7,095 |
| 55 | SUBTOTAL............................... | 395,025 | 18,516 | 376,509 |
| 56 | | | | |
| 57 | | | | |
| 58 | **TOTAL** | $ 3,040,562 | $ 138,265 | $ 2,902,297 |

## OFFICERS

1. Report below the name, title and salary for the year 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 date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K identified as

| Line No. | Title (a) | Name of Officer (b) | Salary for year Total | Salary for year Oregon |
|---|---|---|---|---|
| 1 | | | | |
| 2 | President & Chief Executive Officer…...................................... | Darrel T Anderson | $ 800,000 | $ 37,499 |
| 3 | | | | |
| 4 | Senior Vice President, CFO and Treasurer …........................... | Steven R. Keen | 420,000 | $ 19,687 |
| 5 | | | | |
| 6 | Senior Vice President, COO........................................................ | Lisa Grow | 400,000 | $ 18,750 |
| 7 | | | | |
| 8 | Senior Vice President, Public Affairs........................................... | Jeffrey Malmen | 295,000 | 13,828 |
| 9 | | | | |
| 10 | Senior Vice President, Admin Services & Chief HR Officer…….. | Lonnie Krawl | 300,000 | 14,062 |
| 11 | | | | |
| 12 | Senior Vice President & General Counsel | Brian Buckham | 300,000 | 14,062 |
| 13 | | | | |
| 14 | Vice President, T&D Engineering & Contstruction, and CSO...... | Vern Porter | 295,000 | 13,828 |
| 15 | | | | |
| 16 | Vice President of Power Supply.................................................. | Tessia Park | 265,000 | 12,422 |
| 17 | | | | |
| 18 | Vice President, Customer Operations & Bus. Development......... | Adam Richins | 220,000 | 10,312 |
| 19 | | | | |
| 20 | Vice President, Corporate Controller & CAO............................... | Ken Petersen | 255,000 | 11,953 |
| 21 | | | | |
| 22 | Vice President Information Technology & CIO............................ | Jeff Glenn | 240,000 | 11,250 |
| 23 | | | | |
| 24 | Vice President of Rgulatory Affairs.............................................. | Tim Tatum | 180,000 | 8,437 |
| 25 | | | | |
| 26 | Corporate Secretary...................................................................... | Patrick Harrington | 202,000 | 9,469 |
| 27 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | | | |

## 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 |
|---|---|---|
| ADA COUNTY LINCOLN DAY ASSOCIA | 426.400 | 2,000 |
| BRAD LITTLE FOR IDAHO | " | 5,000 |
| BRANDON WOOLF FOR STATE CONTRO | " | 1,000 |
| CANYON COUNTY REPUBLICANS | " | 500 |
| CARL CRABTREE FOR STATE SENATE | " | 250 |
| CAROLINE TROY FOR STATE REPRES | " | 250 |
| CHAMBER OF COMMERCE - TWIN FAL | " | 1,500 |
| CHERIE BUCKNER-WEBB FOR STATE | " | 500 |
| CHUCK WINDER FOR STATE SENATE | " | 1,000 |
| CLARK KAUFFMAN FOR STATE REPRE | " | 250 |
| CLIFF BAYER FOR STATE SENATOR | " | 500 |
| DAN JOHNSON FOR STATE SENATE | " | 500 |
| DUSTIN MANWARING FOR STATE REP | " | 250 |
| ELAINE SMITH FOR STATE | " | 250 |
| FRED WOOD FOR STATE REPRESENTA | " | 500 |
| GARY COLLINS FOR STATE | " | 500 |
| GRANT BURGOYNE FOR STATE SENAT | " | 250 |
| HOUSE REPUBLICAN PAC | " | 1,000 |
| IDAHO ASSOC OF COMMERCE AND IN | " | 1,000 |
| IDAHO COUNCIL ON INDUSTRY | " | 250 |
| IDAHO DEMOCRATIC LEGISLATIVE C | " | 750 |
| IDAHO LIABILITY REFORM COALITI | " | 2,000 |
| IDAHO MINING ASSOCIATION | " | 398 |
| IDAHO PROSPERITY FUND | " | 15,500 |
| IDAHO REALTORS | " | 1,500 |
| IDAHO STATE SOCIETY | " | 11,706 |
| IDAHO WATER USERS ASSOCIA | " | 2,885 |
| ILANA RUBEL FOR STATE REPRESEN | " | 500 |
| INTERMOUNTAIN ENERGY SUMMIT | " | 5000 |
| JAMES HOLTZCLAW FOR STATE REPR | " | 250 |
| JANET TRUJILLO FOR STATE REPRE | " | 250 |
| JASON MONKS FOR STATE REPRESEN | " | 250 |
| JEFF AGENBROAD FOR STATE SENAT | " | 250 |
| JEFF THOMPSON FOR STATE REPRES | " | 250 |
| JIM PATRICK FOT STATE SENATE | " | 500 |
| JIM RICE FOR STATE SENATE | " | 500 |
| JOHN GOEDDE UNUSED POLITI | " | -1000 |
| KELLY ANTHON FOR STATE SENATE | " | 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 |
|---|---|---|
| LAWERENCE DENNEY FOR SECRETARY | 426.400 | 500 |
| LUKE MALEK FOR STATE REPRESENT | " | 250 |
| MARK NYE FOR STATE SENATE | " | 250 |
| MARYANNE JORDAN FOR STATE SENA | " | 250 |
| MAT ERPELDING FOR STATE REPRES | " | 500 |
| MICHELLE STENNETT FOR STATE SE | " | 500 |
| MIKE MOYLE FOR STATE REPRESENT | " | 500 |
| NASDA/WASDA | " | 2000 |
| NEW HORIZONS PAC | " | 1000 |
| OREGONIANS FOR BALANCED CLIMAT | " | 2500 |
| OTTER PAC | " | 5000 |
| PARSONS BEHLE & LATIMER | " | 2000 |
| PAT MCDONALD FOR STATE REPRESE | " | 250 |
| PAUL AMADOR FOR STATE REPRESEN | " | 250 |
| PUGET SOUND ENERGY FEDERAL GOV | " | 500 |
| RANDY ARMSTRONG FOR STATE REPR | " | 250 |
| RICK YOUNGBLOOD FOR STATE REPR | " | 250 |
| ROBERT ANDERST FOR STATE REPRE | " | 250 |
| SCOTT BEDKE FOR STATE REPRESEN | " | 1000 |
| SENATE REPUBLICAN CAUCUS | " | 1000 |
| SOUTH DAKOTA ELECTRIC UTILITY | " | 811 |
| STEVE VICK FOR STATE SENATOR | " | 500 |
| TERRY GESTRIN FOR STATE REPRES | " | 250 |
| THOMAS DAYLEY FOR STATE REPRES | " | 250 |
| TODD LAKEY FOR STATE SENATE | " | 500 |
| TOM KEALEY FOR IDAHO STATE TRE | " | 500 |
| TOM LOERTSCHER FOR STATE REPRE | " | 500 |
| WENDY HORMAN FOR STATE REPRESE | " | 250 |
| **Total Political Contributions** | | **$ 81,800** |

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 | 426101 | 65,877 | None |
| IDACORP EMPLOYEES | " | 154,123 | " |
| **TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND** | **426101** | **220,000** | |
| AMERICAN HEART ASSOCIATION | 426101 | 7,500 | None |
| AMERICAN RED CROSS OF GREATER | " | 1,000 | " |
| BOISE RESCUE MISSION | " | 3,500 | " |
| CANYON COUNTY FESTIVAL | " | 2,263 | " |
| CHILDREN'S HOME SOCIETY OF ID | " | 1,250 | " |
| DESIGNS BY DE | " | 2,000 | " |
| GIRL SCOUTS OF SILVER SAGE COU | " | 5,000 | " |
| IDAHO HUMANE SOCIETY | " | 1,750 | " |
| IDAHO RONALD MCDONALD HOUSE | " | 2,500 | " |
| LIFE'S KITCHEN | " | 1,500 | " |
| LUPO,MARK J | " | 1,089 | " |
| SALVATION ARMY | " | 2,500 | " |
| SHRINER HOSPITALS FOR CHILDREN | " | 1,000 | " |
| ST ALPHONSUS FESTIVAL OF TREES | " | 5,000 | " |
| ST LUKES HEALTH FOUNDATION | " | 7,500 | " |
| ST LUKES MAGIC VALLEY HEALTH F | " | 2,500 | " |
| WESTERN IDAHO TRAINING CO, INC | " | 1,000 | " |
| Misc Health & Human Services - 41 Organizations <$1,000 | " | 11,352 | " |
| **TOTAL HEALTH & HUMAN SERVICES** | **426102** | **60,204** | |
| ACCESS TO JUSTICE IDAHO | **426103** | 2,500 | None |
| BAKER COUNTY FAIR - HALFWAY | " | 1,031 | " |
| BOISE MUSIC WEEK | " | 1,000 | " |
| BOISE PHILHARMONIC ASSOCIATION | " | 2,500 | " |
| BOYS & GIRLS CLUB OF ADA CO | " | 3,500 | " |
| CHAMBER OF COMMERCE | " | 12,267 | " |
| COMMUNITY FORESTRY TRUST ACCOU | " | 7,000 | " |
| DESTINATION CALDWELL | " | 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 |
|---|---|---|---|
| DISCOVERY CENTER OF IDAHO | 426103 | 2,500 | None |
| EAGLE VALLEY RURAL FIRE PROTEC | " | 5,000 | " |
| FRIENDS OF ZOO BOISE | " | 4,000 | " |
| FUNDSY | " | 2,000 | " |
| GARDEN CITY LIBRARY FOUNDATION | " | 1,500 | " |
| HAILEY, CITY OF | " | 1,000 | " |
| HOME PARTNERSHIP FOUNDATION | " | 2,500 | " |
| HORSESHOE BEND CITY | " | 1,300 | " |
| IDAHO BOTANICAL GARDEN | " | 3,000 | " |
| IDAHO CLIMATE SUMMIT | " | 4,000 | " |
| IDAHO COMMISSION ON HISPA | " | 2,000 | " |
| IDAHO COMMUNITY FOUNDATION | " | 5,000 | " |
| IDAHO DEPARTMENT OF COMMERCE | " | 3,500 | " |
| IDAHO FOODBANK | " | 2,750 | " |
| IDAHO HORSE RESCUE | " | 1,000 | " |
| IDAHO HUMANE SOCIETY | " | 11,250 | " |
| IDAHO NONPROFIT CENTER | " | 2,500 | " |
| IDAHO PATRIOT THUNDER RIDE | " | 1,000 | " |
| IDAHO SALMON AND STEELHEAD DAY | " | 2,500 | " |
| IDAHO STATE UNIVERSITY | " | 2,500 | " |
| LAND TRUST OF THE TREASURE VAL | " | 1,000 | " |
| LUPO,MARK J | " | 6,241 | " |
| MALHEUR COUNTY FAIRGROUND | " | 2,000 | " |
| MARTIN,FRANCES J | " | 1,000 | " |
| MCPAWS REGIONAL ANIMAL SHELTER | " | 1,000 | " |
| NEIGHBORWORKS | " | 4,000 | " |
| PCHD FOUNDATION INC | " | 1,000 | " |
| PORTNEUF VALLEY PAINTFEST | " | 1,000 | " |
| ROTARY CLUB, BOISE | " | 2,000 | " |
| SALMON HOCKEY ASSOCIATION | " | 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 |
|---|---|---|---|
| SALVATION ARMY | 426103 | 28,332 | None |
| SERVE IDAHO | " | 1,600 | " |
| SMART WOMEN, SMART MONEY INC | " | 5,000 | " |
| STAFFORD,BRIANNA N | " | 3,000 | " |
| STUTZMAN,SHARON E | " | 2,097 | " |
| THORNTON,DAVID J | " | 2,297 | " |
| TREASURE VALLEY NAACP | " | 1,500 | " |
| TREEFORT LLC | " | 1,000 | " |
| TWIN FALLS COUNTY FAIR FOUNDAT | " | 1,000 | " |
| TWIN FALLS SENIOR CENTER | " | 1,000 | " |
| WASSMUTH CENTER FOR HUMAN RIGH | " | 1,500 | " |
| WEWERS,BRYAN J | " | 1,831 | " |
| WOMEN'S & CHILDREN'S ALLIANCE | " | 10,000 | " |
| WREATHS ACROSS AMERICA | " | 1,000 | " |
| WYAKIN WARRIOR FOUNDATION | " | 3,500 | " |
| Misc Civic and Community Serivices - 146 Organizations < $1,000 | " | 54,798 | " |
| **TOTAL CIVIC & COMMUNITY** | **426103** | **232,294** | |
| BASQUE MUSEUM AND CULTURAL CEN | 426104 | 2500 | " |
| BOISE ART MUSEUM | " | 3000 | " |
| IDAHO SHAKESPEARE FESTIVAL | " | 3500 | " |
| LOG CABIN LITERARY CENTER | " | 2000 | " |
| MAGIC VALLEY ARTS COUNCIL | " | 2500 | " |
| MERIDIAN SYMPHONY ORCHESTRA | " | 1500 | " |
| OPERA IDAHO INC | " | 2500 | " |
| Misc Culture and Arts - 22 Organizations <$1,000 | " | 3,165 | " |
| **TOTAL CULTURE & ARTS** | **426104** | **20,665** | |
| IDAHO PUBLIC TELEVISION | 426105 | 20,000 | None |
| **TOTAL PUBLIC TV & RADIO MATCH** | **426105** | **20,000** | |
| Misc Volunteer Involvement Programs- 44 Organizations <$1,001 | 426106 | 5,600 | None |
| **TOTAL VOLUNTEER INVOLVEMENT PROGRAM** | **426106** | **5,600** | |

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 |
|---|---|---|---|
| SALVATION ARMY | 426107 | 42,743 | None |
| **TOTAL PROJECT SHARE** | **426107** | **42,743** | |
| FRESHWATER TRUST, THE | 426108 | 2,500 | None |
| Misc Education Programs - 3 Organizations <$1,000 | 426108 | 900 | " |
| **TOTAL ENVIROMENT & CONSERVATION** | **426108** | **3,400** | |
| BOISE VALLEY ECONOMIC PARTNERS | 426109 | 1,000 | None |
| FOUNDATION FOR IDAHO HISTORY, | " | 25,000 | " |
| IDAHO BUSINESS FOR EDUCATION | " | 5,000 | " |
| IDAHO GOVERNOR'S CUP SCHOLARSH | " | 17,500 | " |
| IDAHO TECHNOLOGY COUNCIL | " | 1,500 | " |
| JAIME OLIVAS DONATION ACCOUNT | " | 10,000 | " |
| SUPPORT OUR TROOPS | " | 5,000 | " |
| TEACH FOR AMERICA | " | 10,000 | " |
| TRAILHEAD | " | 1,000 | " |
| **TOTAL NON-PROGRAM** | **426109** | **76,000** | " |
| BOISE PUBLIC SCHOOLS | 426110 | 3000 | None |
| BOISE STATE UNIVERSITY FOUNDAT | " | 1000 | " |
| COLLEGE OF IDAHO | " | 3500 | " |
| COLLEGE OF SOUTHERN IDAHO | " | 3000 | " |
| COLLEGE OF WESTERN IDAHO | " | 3500 | " |
| COLLEGE OF WESTERN IDAHO FOUND | " | 1200 | " |
| IDAHO STATE UNIVERSITY | " | 2750 | " |
| IDAHO STEM ACTION CENTER | " | 1500 | " |
| JUNIOR ACHIEVEMENT OF IDAHO | " | 5400 | " |
| LEARNING LAB | " | 1000 | " |
| NORTHWEST NAZARENE UNIVERSITY | " | 3500 | " |
| POCATELLO / CHUBBUCK SCHOOL DI | 426110 | 1500 | " |
| SOCIETY OF WOMEN ENGINEERS | " | 2500 | " |
| TREASURE VALLEY COMMUNITY COLL | " | 3500 | " |
| UNIVERSITY OF IDAHO | " | 6,000 | " |

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

| Description | Account Number | Total Amount | Amount Assigned to Oregon |
|---|---|---|---|
| Misc Education Programs - 48 Organizations <$1,000 | " | 11,923 | " |
| **TOTAL EDUCATION** | **426110** | **54,773** | |
| BOISE STATE UNIVERSITY | 426111 | 4,000 | None |
| BOISE STATE UNIVERSITY - SCHOL | " | 14,000 | " |
| BRIGHAM YOUNG UNIVERSITY CES A | " | 8,000 | " |
| BRIGHAM YOUNG UNIVERSITY IDAHO | " | 2,000 | " |
| COLLEGE OF IDAHO | " | 2,000 | " |
| COLLEGE OF SOUTHERN IDAHO | " | 2,666 | " |
| EASTERN OREGON UNIVERSITY | " | 2,000 | " |
| HUMBOLDT STATE UNIVERSITY | " | 2,000 | " |
| IDAHO STATE UNIVERSITY | " | 10,000 | " |
| NORTHWEST NAZARENE UNIVERSITY | " | 2,000 | " |
| PORTLAND STATE UNIVERSITY | " | 2,000 | " |
| TREASURE VALLEY COMMUNITY COLL | " | 6,000 | " |
| UNIVERSITY OF CALIFORNIA | " | 2,000 | " |
| UNIVERSITY OF IDAHO | " | 2,000 | " |
| Unused Scholorship | " | (666) | " |
| **TOTAL SCHOLARSHIP PROGRAMS** | **426111** | **60,000** | " |
| BOISE STATE UNIVERSITY MS 1045 | 426112 | 1,600 | None |
| COLLEGE OF IDAHO | " | 2,045 | " |
| COLLEGE OF WESTERN IDAHO NAMPA | " | 1,000 | " |
| IDAHO STATE UNIVERSITY | " | 2,735 | " |
| NORTHWEST NAZARENE UNIVERSITY | " | 2,000 | " |
| UNIVERSITY OF IDAHO FOUNDATION | " | 7,275 | " |
| Misc Non-Cash Contributions - 7 Organizations <$1,000 | " | 1,225 | " |
| **TOTAL HIGHER EDUCATION MATCH** | **426112** | **17,880** | |
| EEI | 426120 | 15,000 | None |
| **TOTAL COMM & TRADE MEMBERSHIPS** | **426120** | **15,000** | |
| BANNOCK DEVELOPMENT CORPO | 426121 | 1,500 | None |
| BOISE STATE UNIV. GAMING AND M | " | 5,000 | " |

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

| Description | Account Number | Total Amount | Amount Assigned to Oregon |
|---|---|---|---|
| BOISE VALLEY ECONOMIC PARTNERS | " | 2,345 | " |
| DESTINATION CALDWELL | " | 1,500 | " |
| DOWNTOWN BOISE ASSOCIATION | " | 1,500 | " |
| EASTERN IDAHO ECONOMIC | " | 3,000 | " |
| GREAT RIFT BUSINESS DEVELOPMEN | " | 1,450 | " |
| LEMHI COUNTY ECONOMIC DEVELOPM | " | 2,201 | " |
| MERIDIAN, CITY OF | " | 1,500 | " |
| MOUNTAIN HOME, CITY OF | " | 2,145 | " |
| REGIONAL ECONOMIC DEVELOPMENT | " | 1,000 | " |
| SNAKE RIVER ECONOMIC DEVELOPME | " | 2,250 | " |
| SOUTHERN IDAHO RURAL DEVELOPME | " | 3,215 | " |
| SUN VALLEY ECONOMIC DEVELOPMEN | " | 1,500 | " |
| WEST CENTRAL MOUNTAINS ECONOMI | " | 1,500 | " |
| Misc Match Higher Education - 7 Organizations <$1000 | " | 5,080 | " |
| **TOTAL ECONOMIC DEVELOPMENT** | **426121** | **36,686** | |
| PEREGRINE FUND | 426130 | 8,000 | None |
| SAND HOLLOW FIRE DISTRICT | " | 7,000 | " |
| Misc Non-Cash Contributions - <$1,000 | " | 1,131 | " |
| **TOTAL NON-CASH CONTRIBUTIONS** | **426130** | **16,131** | |
| **TOTAL CONTRIBUTIONS ACCOUNT 426.1** | | **881,377** | |

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<br>(a) | Nature of Service<br>(b) | Amount of Payment Allocated to Oregon<br>(c) |
|---|---|---|---|
| 1 | ANDERSON SCHWARTZMAN WOODARD B | Legal Services | $ 6,399 |
| 2 | AVERTRA CORPORATION | Management Services | 9,855 |
| 3 | BARKER, ROSHOLT & SIMPSON LLP | Legal Services | 24,367 |
| 4 | CGI TECHNOLOGIES AND SOLUTIONS | IT Services | 24,692 |
| 5 | CLEAREDGE PARTNERS | Training Consultants | 5,557.46 |
| 6 | COMPUNET, INC | IT Services | 1,281 |
| 7 | DAVIS WRIGHT TREMAINE LLP | Legal Services | 47,274 |
| 8 | DEERE AND AULT CONSULTANTS INC | Envirnmental Services | 1,239 |
| 9 | EVANS KEANE | Legal Services | 1,549 |
| 10 | EVERGREEN CONSULTING GROUP, LL | Management Services | 18,939 |
| 11 | EXTRAHOP SERVICES A | IT Services | 1,940 |
| 12 | GIVENS PURSLEY LLP | Legal Services | 2,437 |
| 13 | HONEYWELL INTERNATIONAL INC | Management Services | 5,222 |
| 14 | INTELLITECT | Management Services | 7,026 |
| 15 | KEMA INC | Management Services | 3,722 |
| 16 | LEIDOS ENGINEERING LLC | Engineering Services | 2,672 |
| 17 | MCDOWELL RACKNER & GIBSON PC | Legal Services | 26,355 |
| 18 | NIELSEN GROUP INC, THE | IT Services | 7,704 |
| 19 | PERKINS COIE LLP | Legal Services | 10,516 |
| 20 | REED HARRIS ENVIRONMENTAL LTD | Envirnmental Services | 1,992 |
| 21 | REGULUS INTEGRATED SOLUTIONS | Customer Service | 4,219 |
| 22 | RESOURCE DATA, INC | IT Services | 11,822 |
| 23 | RM ENERGY CONSULTING | Management Services | 15,461 |
| 24 | SAP INDUSTRIES | IT Services | 3,094 |
| 25 | SCHWABE WILLIAMSON & WYATT | Legal Services | 2,110 |
| 26 | TATA AMERICA INTERNATIONAL | Management Services | 16,028 |
| 27 | THE REGENTS OF UNIVERSITY OF CA | Environmental Services | 1,766 |
| 28 | TIBCO SOFTWARE INC | IT Services | 4,192.89 |
| 29 | TRINITY CONSULTANTS INC | Environmental Services | 1,638 |
| 30 | TRINOOR LLC | HR Consulting | 7,558 |
| 31 | TUERI LLC | Management Services | 2,567 |
| 32 | UNIVERSITY OF IDAHO | Management Services | 16,157 |
| 33 | UT-BATTELLE LLC | Environmental Services | 4,493 |
| 34 | VAN NESS FELDMAN | Legal Services | 8,832 |
| | **TOTAL** | | $ 310,677 |

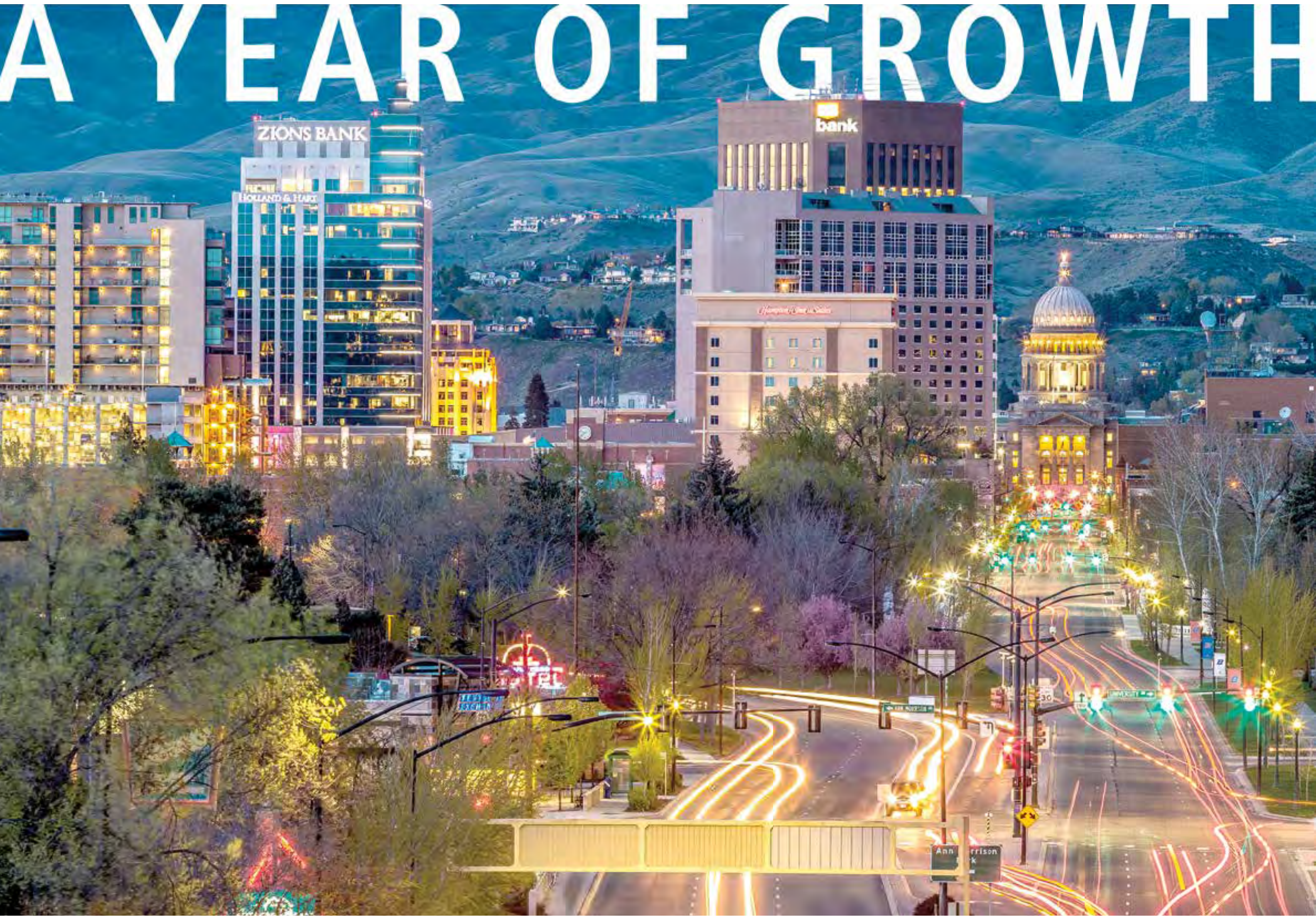
# Annual Report

2017

7% Earnings Growth

2% Customer Growth

7% Dividend Growth




IDACORP

# Annual review

## To Our Valued Shareholders:

2017 was another year filled with many successes for IDACORP, Inc., highlighted by achieving a 10th consecutive year of earnings growth. IDACORP provided a 15 percent cumulative annual total shareholder return over the past three years, including share price appreciation and dividends paid, ranking in the 85th percentile among peer companies in the Edison Electric Institute Electric Utilities Index. A contributing factor in this return has been increases in IDACORP's quarterly common stock dividend, which has increased 97 percent since 2011, most recently from $0.55 to $0.59 per share.

A significant driver of increased earnings has been customer growth at Idaho Power, IDACORP's principal operating subsidiary. Idaho Power's customer count grew by 2.0 percent from 2016 to 2017, and sales volumes to industrial customers increased 3.2 percent over the same period.

We have continued to focus on productive regulatory outcomes, such as Idaho Power's process established with the Idaho and Oregon public utilities commissions to end its participation in coal-fired operations at the North Valmy power plant units 1 and 2 in 2019 and 2025, respectively. In addition, we kept other operations and maintenance expenses relatively flat for the sixth consecutive year.

At the same time, Idaho Power has continued to focus on customer satisfaction, ranking second in J.D. Power's Electric Business Customer Satisfaction Study for the West Midsize segment. We continue to manage our environmental impact by achieving and

## contents



## 2017 HIGHLIGHTS

Dollar Amounts in Thousands, Except Per Share Amounts

| | 2017 | 2016 | % CHANGE |
|---|---|---|---|
| Total Operating Revenues | $1,349,486 | $1,262,020 | 6.93 |
| Net Income | $212,419 | $198,288 | 7.12 |
| Earnings Per Diluted Common Share | $4.21 | $3.94 | 6.85 |
| Dividends Declared Per Common Share | $2.24 | $2.08 | 7.69 |
| Total Assets | $6,045,405 | $6,289,897 | -3.89 |
| Number of Employees (full-time) | 1,972 | 2,008 | -1.79 |

Robert A. Tinstman Darrel T. Anderson

extending our $CO_2$ emissions intensity reduction goal, resulting in coal accounting for less of our total energy supply. Coal accounted for just 18 percent of Idaho Power's total power supply in 2017—down from 24 percent in 2016.

At IDACORP, we are focused on the future. Our four-part strategy focuses first on growth to enhance our financial strength. We have increased our business development efforts, and we expect those increases to bring additional load growth to Idaho Power over the next few years. We are committed to exploring new revenue opportunities, and we foresee opportunities for Idaho Power to provide behind-the-meter services and solutions. We will continue to promote and engage in electrification, such as leveraging electric vehicle partnerships and making progress toward electrifying third-party vehicle and equipment fleets.

The second part of our strategy focuses on improving the core business. We will continue to upgrade our infrastructure for growth, technology changes, renewable energy integration and flexibility by achieving milestones associated with large projects and executing on capital projects highlighted in our most recent Integrated Resource Plan. With efforts such as joining the Western Energy Imbalance Market, we will further work to optimize wholesale transmission and energy sales. We are committed to operating efficiently and controlling expenditures. We are executing our plans to use technology, such as data analytics and security programs, to enhance our grid, system reliability and safety. And we continue to focus on implementing rate structures that are fair and reasonable to all customers, such as ensuring potential cost reductions resulting from the Tax Cuts and Jobs Act are passed along to customers.

The third focus of our strategy is to enhance Idaho Power's brand. We recognize that our customers want choices and transparency. We want our customers to see us as their trusted energy advisor and to feel that they matter to Idaho Power. We are focusing on enhancing our customers' experience and interactions through simplification, transparency and targeted communications. We also believe continued environmental stewardship, emission reductions and constructive regulatory relationships serve to enhance our brand in the eyes of all customers.

The final part of our strategy, which encompasses everything we do, maintains a focus on safety and employee engagement.

We understand our unique role in the communities we serve as energy advisors and environmental stewards. We are adapting to technological changes through our customer-owned generation regulatory filing in Idaho to provide clarity and fairness in response to how all customers choose to utilize the energy grid, as well as utilizing cost-effective, innovative battery storage and end-of-feeder solar solutions in parts of our service area. We are committed to managing our impact on the environment by continuing our excellent track record of stewardship, such as the Bayha Island research project, the Hells Canyon relicensing process and continuing our glide path away from coal.

We believe in our strategy, and we thank you for your continued investment in IDACORP as you join us on our journey to achieve our mission and prosper by providing reliable, responsible, fair-priced energy services, today and tomorrow.

Robert A. Tinstman
Chairman of the Board

Darrel T. Anderson
President and Chief Executive Officer

welcome

In 2017, IDACORP enjoyed a year filled with growth and success. Our primary subsidiary, Idaho Power, continued to benefit from economic development across southern Idaho and eastern Oregon while serving more customers than ever before.

2017 marked our 10th consecutive year of earnings growth. Customer growth of 2.0 percent increased general business revenue $12.1 million in 2017 compared with 2016. Net income increased $14.1 million.

Low-cost energy continued to attract new customers to Idaho Power's service area. In August, Bloomberg named Idaho as the top performing economy in the nation. Idaho also ranked No. 6 on CNBC's recent list of "America's 10 cheapest states to live in 2017," which used a variety of factors to calculate a cost of living score. One of those factors was the average cost of residents' monthly energy bills — Idaho had the second-lowest rates on that list.

We finished the year with under $350 million of O&M expenses, putting us near the $350 million mark for the sixth year in a row. Our efforts to control costs continue to pay off for the company, its customers and its shareholders.

## Guidance

$4.21 PER DILUTED SHARE

2017 ended with earnings of $4.21 per diluted share. On Feb. 22, 2018, we initiated earnings guidance for the full year 2018 in the range of $4.10 to $4.25 per diluted share.

## Dividend Growth

IDACORP continued to advance toward the upper end of its target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, which expanded on progress made in previous years.

From 2011 through 2017, IDACORP's board of directors approved a collective 97% INCREASE in the quarterly dividend, from $0.30 to $0.59 per share. In 2017, we increased IDACORP's quarterly common stock dividend from $0.55 per share to $0.59 per share. We are committed to recommending future dividend growth of at least 5 percent or more to the board of directors until we reach the upper end of our 50-to-60 percent targeted payout ratio.

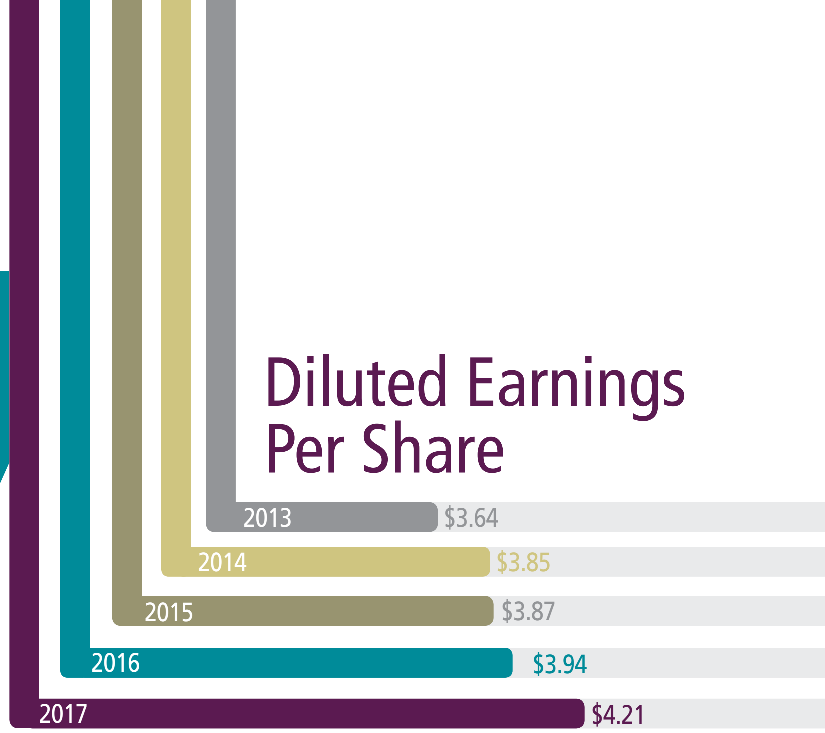
## Capital Expenditures

Idaho Power continues to enhance its utility infrastructure. Noteworthy ongoing capital projects include upgrading aging assets and generation plants, replacing underground conductor and continuing to advance the Boardman to Hemingway and Gateway West 500-kV transmission projects. Idaho Power estimates total capital expenditures of nearly $1.5 billion over the next five years.

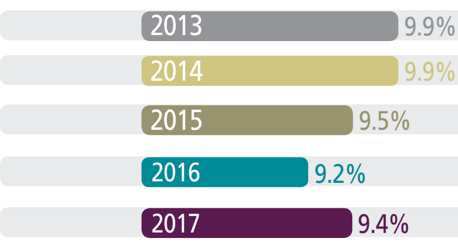
These infrastructure investments help Idaho Power ensure an adequate supply of electricity, provide service to new customers and maintain system reliability. In 2018, we expect capital expenditures to be relatively consistent with 2017, with an estimated range of $280 million to $290 million.

# COMPARING THE NUMBERS 17

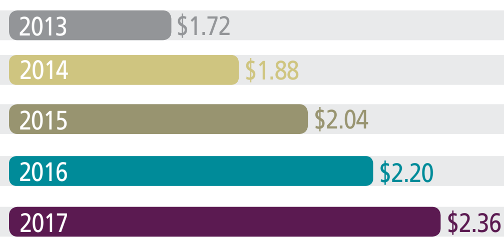
## Diluted Earnings Per Share



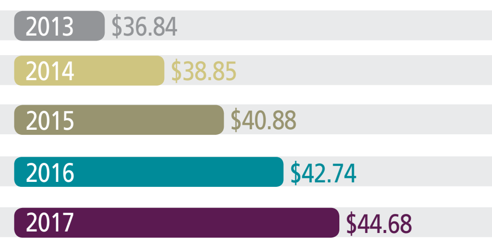

### Return on Year-End Equity



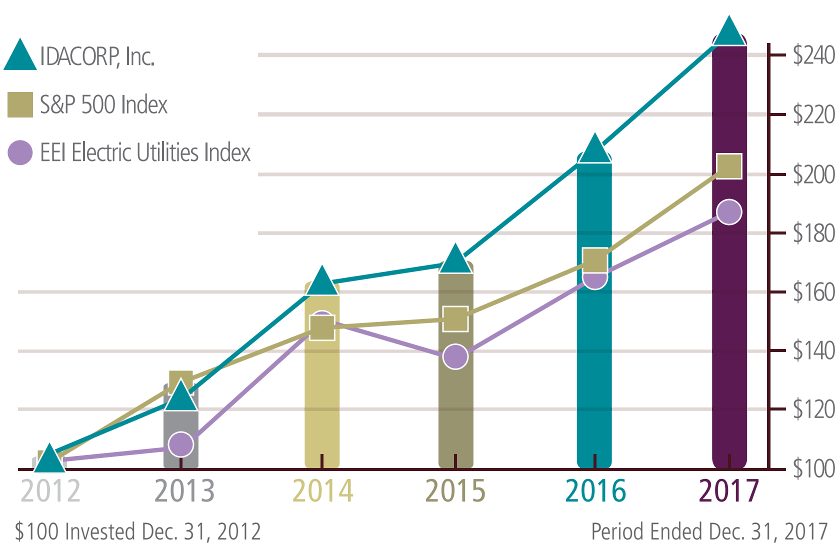

### Annualized Year-End Dividend Per Share



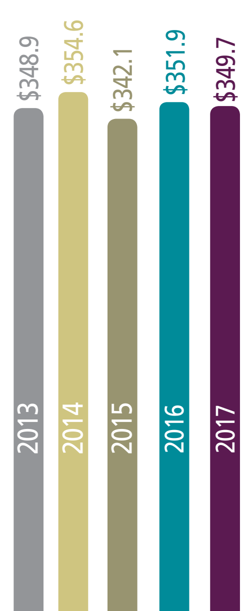

### Book Value Per Share




### Comparison of Cumulative Total Return



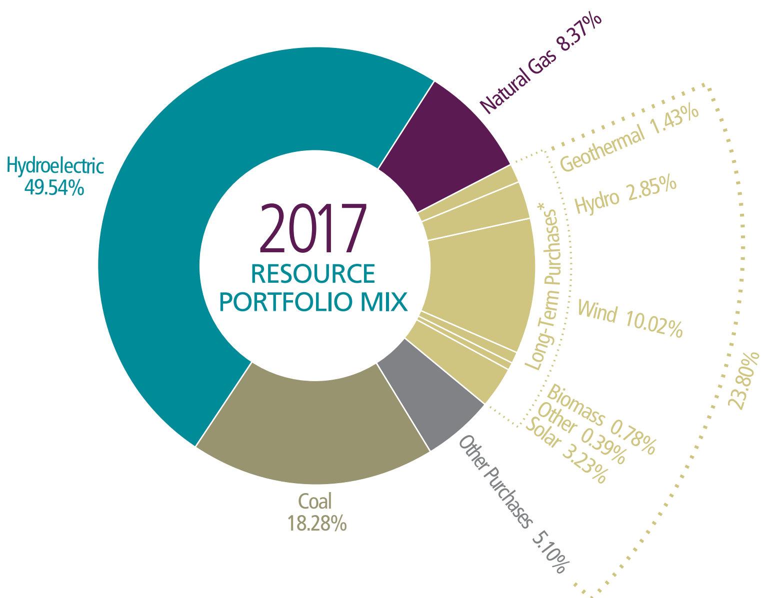

### Operations & Maintenance Expenses

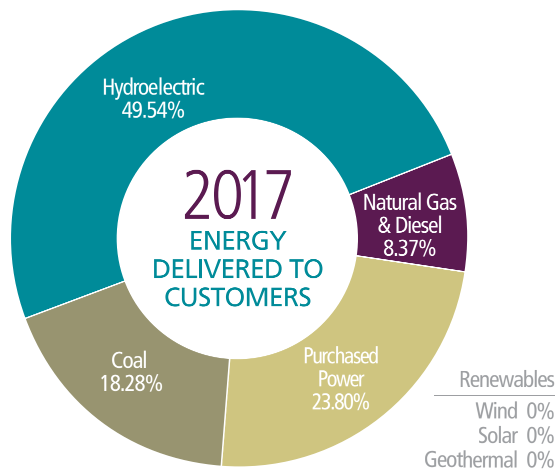


## A Diverse Resource Portfolio

Idaho Power's hydroelectric facilities comprise nearly half of our nameplate generation capacity. Customers are served by 17 dams on the Snake River and its tributaries, as well as three natural gas-fired power plants and three coal-fired plants in which Idaho Power is part-owner. The graphs on this page break down the company's resource portfolio mix.

Idaho Power continues to work toward renewing a long-term federal license for the three-dam Hells Canyon Complex, the company's largest generation resource. In late 2017, the company reached a tentative settlement with IPUC staff calling for approximately $216.5 million in expenditures related to the relicensing of the Hells Canyon Complex to be designated as reasonable and eligible to be recovered in a future rate case. The settlement is pending final approval by the IPUC as of the printing of this report.



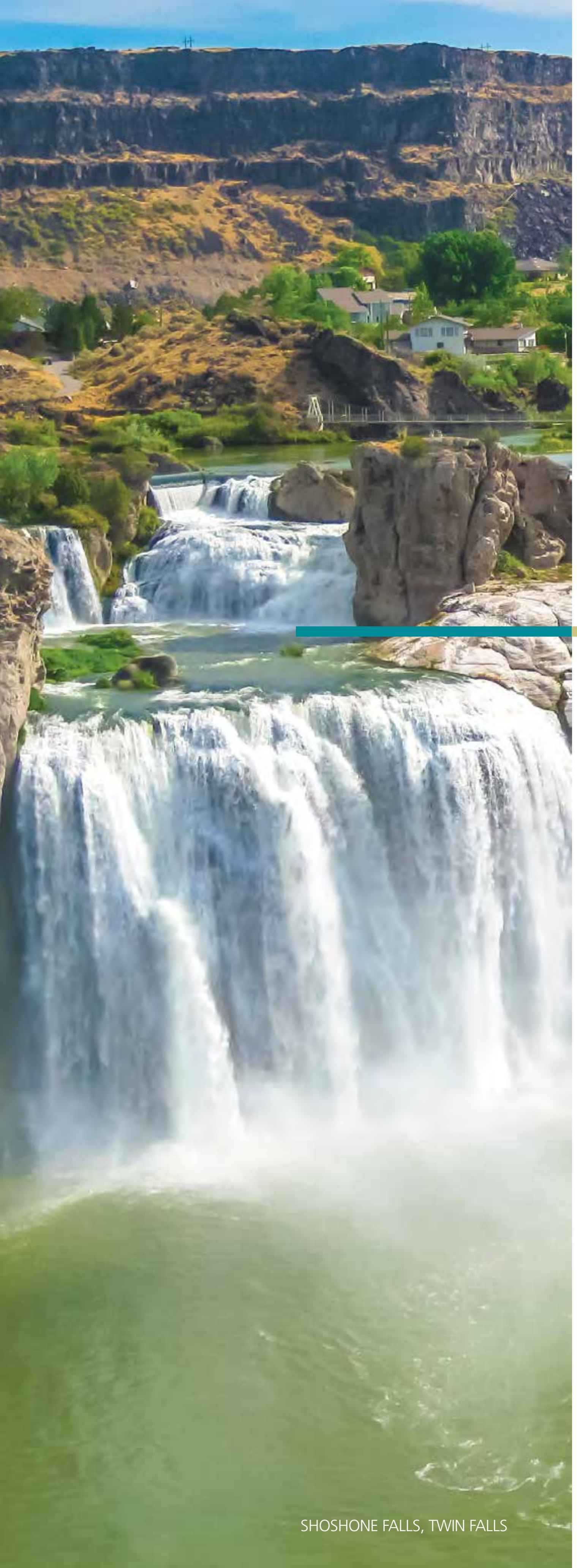




*Idaho Power sells the Renewable Energy Certificates (RECs) that it receives in association with this energy, with proceeds benefiting retail customers. Because Idaho Power does not own the RECs for the other qualified renewable resources included in our Resource Portfolio Fuel Mix, Idaho Power cannot and does not represent that electricity produced by this resource mix is being delivered to its retail customers.

**17 DAMS ON THE SNAKE RIVER & TRIBUTARIES**

**3,422 all-time PEAK demand record MEGAWATTS JULY 7, 2017**

**HYDRO 49.5% OF FUEL MIX**



SHOSHONE FALLS, TWIN FALLS

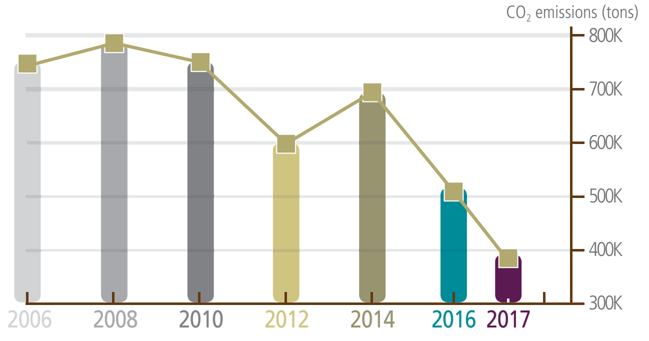


## Renewables and PURPA

Idaho Power has contracts for the purchase of power from both cogeneration and small power production (CSPP) and non-CSPP renewable generation sources such as biomass, wind, solar, small hydroelectric projects and two geothermal projects. Idaho Power purchases wind power from both 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 Dec. 31, 2017, Idaho Power had contracts to purchase energy from 127 on-line CSPP projects, one biomass project expected to come on-line in 2018 and four solar projects scheduled to come on-line in 2019.

### Estimated Idaho Power $CO_2$ Emissions




## Social and Environmental Responsibility

Reducing $CO_2$ emissions continues to be a goal for Idaho Power. The company exceeded its $CO_2$ emissions reduction goals in 2017, with both total emissions and emissions intensity reaching new lows. The company's diverse generation portfolio and long-term resource planning point toward continued $CO_2$ emissions reductions in the future.

In addition, Idaho Power employees continued to practice good environmental stewardship in 2017. Examples include the ongoing Bayha Island research project; work to boost anadromous fish populations and protect birds of prey; and two line crews who demonstrated their commitment to the environment by rescuing a honeybee colony near Twin Falls and a young osprey at Swan Falls Dam.

## 2017 Integrated Resource Plan

Idaho Power plans for infrastructure that will support anticipated growth and allow us to continue to provide reliable, responsible, fair-priced energy to our customers. Every two years, Idaho Power updates its Integrated Resource Plan (IRP) with the participation of the IRP Advisory Council.

The 2017 IRP was filed with state regulators in June. Key action items identified in the IRP include continued planning for participation in the Western Energy Imbalance Market (EIM), planning and coordinating with our operating partners for early retirement of some coal-fired units and pre-construction activities for the Boardman to Hemingway 500-kilovolt transmission line.

HEMINGWAY SUBSTATION

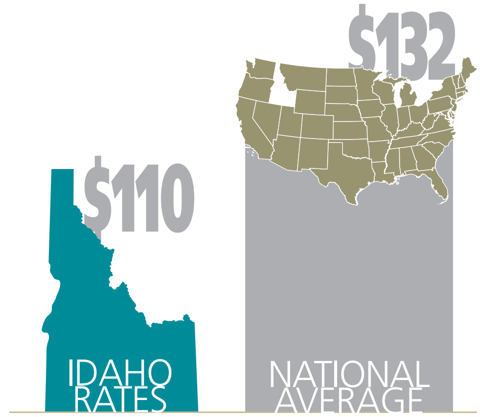
## 500-kilovolt Transmission Projects

The Boardman to Hemingway Transmission Line Project reached a major milestone in November 2017, as the Bureau of Land Management (BLM) released its Record of Decision for the proposed 300-mile, 500-kV transmission line that will run from southern Idaho to northeast Oregon. The project continues to move forward, with an anticipated in-service date of 2025 or beyond.

The Gateway West project also progressed in 2017. Federal legislation included provisions to route the 1,000-mile, 500-kV Gateway West line through the Morley Nelson Snake River Birds of Prey National Conservation Area, and the BLM is expected to soon issue a right-of-way grant for the line sections that cross that area.

## Low Rates

Idaho Power customers continue to enjoy some of the lowest energy rates in the nation. Thanks to our low-cost hydroelectric power, diverse generation portfolio and purposeful regulatory strategy, our business continues to earn a fair return on investments while keeping customer rates low. Our last general rate case was filed in 2011 — in 2018, we will continue assessing the need to file a general rate case in the coming years.




Monthly Residential Rates

Data Source: Edison Electric Institute

## ADITC Preservation

Idaho Power's efforts have been targeted on preserving Accumulated Deferred Investment Tax Credits (ADITC) under a 2014 regulatory settlement. We will continue to be diligent in managing costs and growing revenues with the goal to preserve credits for future years. The company did not use any additional ADITC amortization during 2017. This preserves the full $45 million of credits for future years.


## Valmy Rate Base Adjustment Stipulations

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for the coal-fired North Valmy power plant. The stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year and accelerated depreciationon unit 1 through 2019 and unit 2 through 2025.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through Dec. 31, 2025, cost recovery of incremental Valmy plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, with yearly adjustments to the level of decommissioning cost recovery, if warranted, until decommissioning activities are concluded.

As required by the Idaho stipulation, Idaho Power is working closely with the co-owner of the Valmy plant to end Idaho Power's participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025.

## Energy Imbalance Market

In March 2016, Idaho Power signed an agreement to participate in the Western EIM beginning in April 2018, contingent upon necessary regulatory approvals and other conditions. The Western EIM is intended to reduce the power supply cost to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation resources more effectively and to enhance reliability.

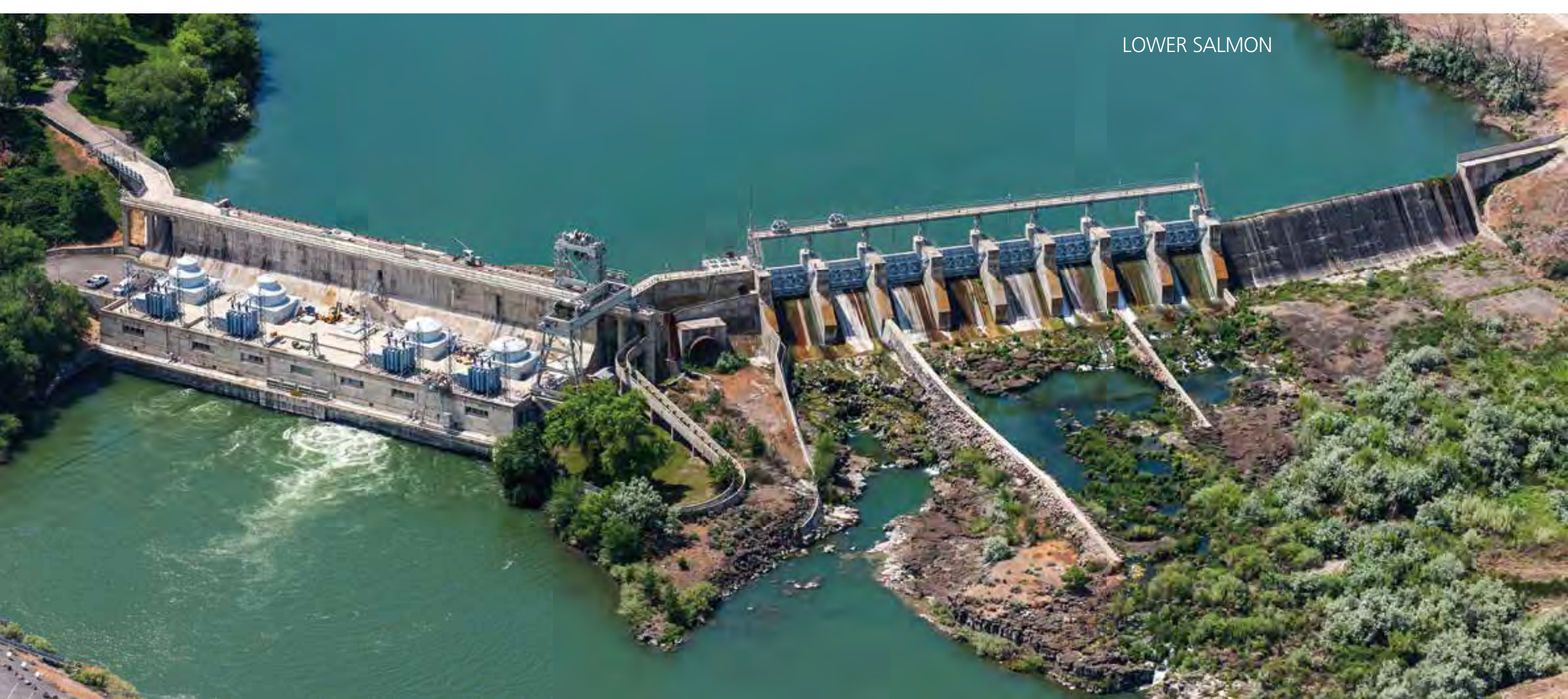
Idaho Power is working on completing its final readiness criteria. On Feb. 1, 2018, Idaho Power entered "parallel operations," where efficient dispatch occurs, but the bids into the market are not financially binding. This is the final stage for operational preparedness prior to expected full participation on April 4, 2018.

## Regulatory Mechanisms

To address the volatility of power supply costs, Power Cost Adjustment (PCA) mechanisms in Idaho and Oregon 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 Idaho Power (5 percent), with the exception of PURPA power purchases and demand response program incentives, which are allocated 100 percent to customers.

As approved, the 2017 PCA increase was $10.6 million, effective June 1, 2017. The main factors contributing to the increase included higher costs associated with new solar and wind power purchase agreements under PURPA, higher coal-fired generation costs, and prior year actual power costs exceeding forecast costs due to worse-than-expected water conditions in 2016.

The 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. In 2017, a $6.9 million increase in annual revenue was approved for the FCA.


LOWER SALMON

**CUSTOMER BASE** MORE THAN
**545,000**
**2% GROWTH**

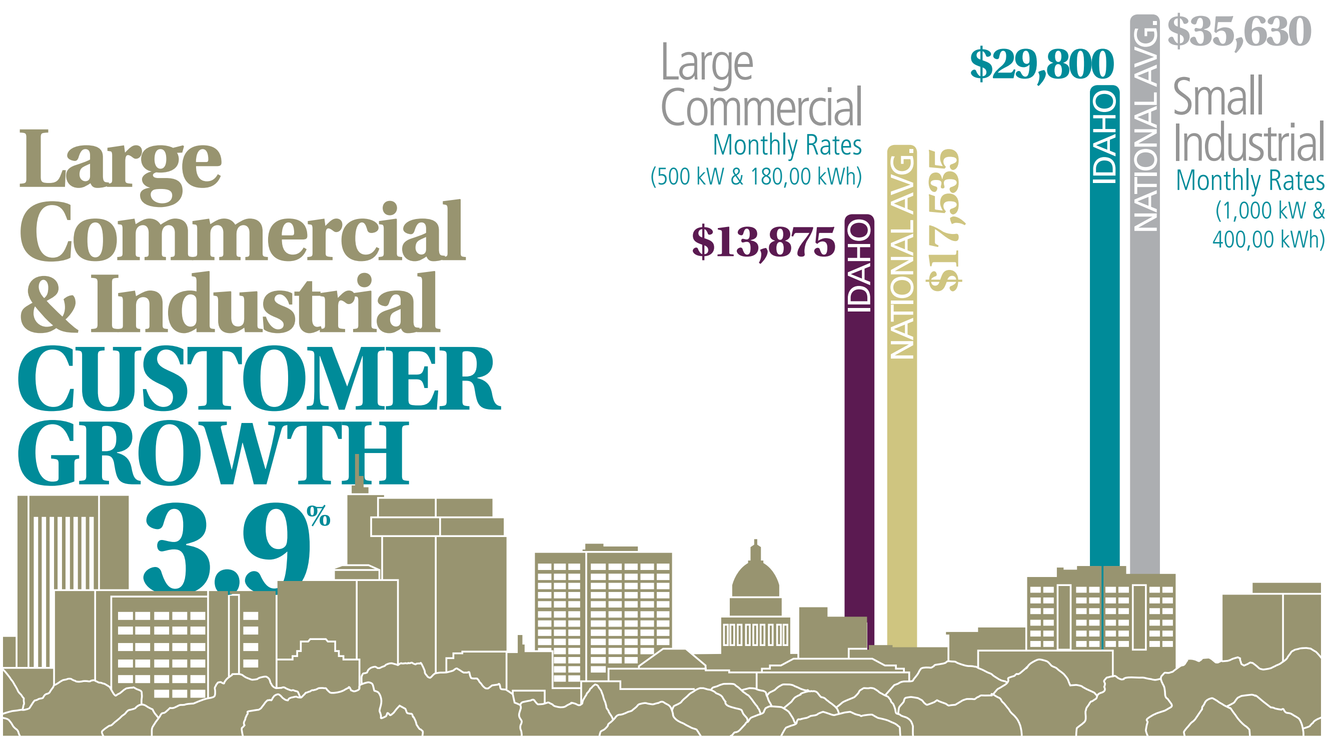
## Customer Growth

Idaho Power continues to see growth within its service area—its customer base grew by 2.0 percent in 2017 and employment grew by approximately 3.7 percent. Our total general business customer base has grown to more than 545,000. And on July 7, the company set an all-time peak demand record of 3,422 MW. Customer growth in Idaho Power's service area continues to positively impact revenues.

## Economic Development

Idaho's economy continues to thrive. According to a recent Bloomberg article, Idaho has the strongest economy in the nation based on an index that measures employment, personal income, home prices, mortgage delinquency, tax revenue and the stock market.

Economic development brings great opportunities for large commercial and industrial growth. Idaho Power's energy sales for this customer segment increased 3.9 percent in 2017, reflecting growth that is largely due to an increase of new and expanding customers, such as CS Beef Packers, Great Western Malting and Woodgrain Millwork. In addition, Capitol Distributing began construction on a 200,000 square-foot distribution center in Caldwell that will serve 450 convenience stores, and McCain Foods announced a $200 million expansion to its frozen potato processing facility in southern Idaho. Future expansions include Jayco, St. Luke's and the Federal Bureau of Investigation, to name a few.




Data Source: Edison Electric Institute

## Customer Experience

Improving the customer experience was a focus for Idaho Power in 2017. We undertook a series of strategic initiatives aimed at showing customers that they matter to us, that they can count on us to provide reliable service and that we promptly address customer needs and find innovative solutions. We streamlined many customer touchpoints to make it easier for people to do business with us, and we continued to be thoughtful, engaged members of the community. Our effort paid off with a 39-point increase in the annual J.D. Power Residential Customer Satisfaction survey, from 704 in 2016 to 743 in 2017 — a new all-time high. We are continuing to emphasize the customer experience going forward.

## Looking Forward

2017 was filled with growth and success for IDACORP. From setting new records in our customer satisfaction rating and peak demand to achieving a 10th consecutive year of earnings growth, Idaho Power continued to thrive. Our 1,972 dedicated employees stood out as environmental stewards and corporate citizens while helping the company reach its business goals.

As we look to the future, we are planning for Idaho Power to continue to grow and prosper as our service area attracts new business and residential customers. In addition to a continued focus on the customer experience, our company's goals in 2018 include growing to enhance financial strength, improving our core business, enhancing our brand and focusing on safety and employee engagement.

Idaho Power remains dedicated to providing reliable, responsible, fair-priced energy, today and tomorrow. Our commitment to our core values of integrity, safety and respect remains strong. And our path forward is clear as we work to continue to grow our business and shareholder value. We appreciate your continued investment in IDACORP, and we look forward to another great year in 2018.

# Board of Directors

## IDACORP & Idaho Power

**Robert A. Tinstman***
(1999) Boise, Idaho
Former Executive Chairman of James Construction Group; former President and Chief Executive Officer and Director of Morrison-Knudsen Corp.; Director of Primoris Services Corp.; Director of Westmoreland Coal Company; former Director of CNA Surety and Home Federal Bancorp.

**Darrel T. Anderson**
(2013) Boise, Idaho
President and Chief Executive Officer of IDACORP, Inc. and Idaho Power.

**Thomas E. Carlile**
(2014) Boise, Idaho
Former Chief Executive Officer of Boise Cascade Company; Director of Boise Cascade Company.

**Richard J. Dahl**
(2008) Kailua, Hawaii
Chairman of the Board and former President and Chief Executive Officer of James Campbell Company, LLC; Director, DineEquity, Inc.; Director, Hawaiian Electric Industries, Inc. and Hawaii Electric Company; former President and Chief Operating Officer of Dole Food Company.

**Annette G. Elg**
(2017) Boise, Idaho
Former Senior Vice President and Chief Financial Officer of J.R. Simplot Company; former Vice President and Controller of J.R. Simplot Company; former Director of Cascade Bancorp.

**Ronald W. Jibson**
(2013) North Salt Lake, Utah
Former President and Chief Executive Officer and Director and Chairman of the Board of Questar Corporation; former President and Chief Executive Officer of Wexpro Corporation and Questar Gas Company; former Chairman of the Board of Directors of Questar Pipeline Company; Director of Dominion Energy, Inc.

( ) year appointed or elected to the board
* Chairman of the Board

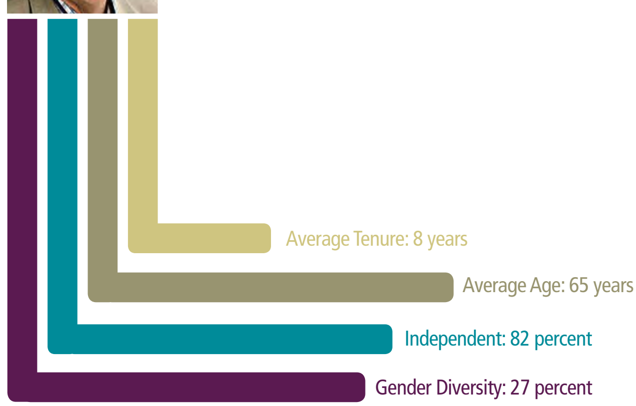
**Judith A. Johansen**
(2007) Scottsdale, Arizona
Former President of Marylhurst University; former President and Chief Executive Officer of PacifiCorp; former Chief Executive Officer and Administrator of the Bonneville Power Administration; Director of Schnitzer Steel and Roseburg Forest Products; former Director of Pacific Continental Corporation.

**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; Director of First Interstate Bancorp; former Director of Cascade Bancorp.

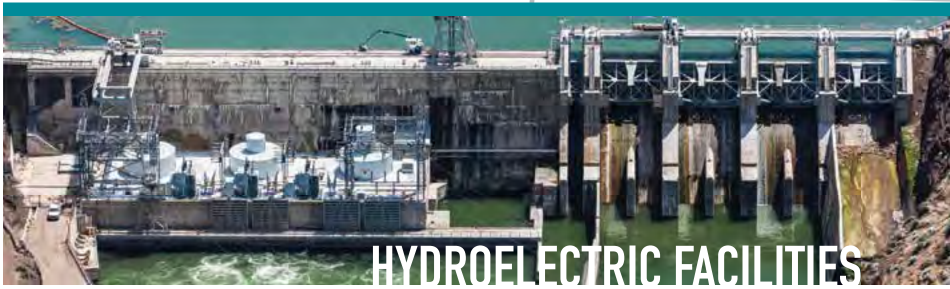
**J. LaMont Keen**
(2004) Boise, Idaho
Former President and Chief Executive Officer, IDACORP, Inc. and Idaho Power; former Director of Cascade Bancorp.

**Christine King**
(2006) Scottsdale, Arizona
Former President and Chief Executive Officer of Standard Microsystems Corporation; former Chief Executive Officer and Director of AMI Semiconductor; Director of Cirrus Logic, Inc. and Skyworks Solutions, Inc.; former Director and Executive Chair of QLogic Corp.; former Director of Standard Microsystems Corporation.

**Richard J. Navarro**
(2015) Boise, Idaho
Former Chief Financial Officer of Albertson's, LLC; former Senior Vice President and Controller at Albertson's, Inc.; former Director of Home Federal Bancorp.



# GENERATION FACILITIES & NAMEPLATE CAPACITIES

## 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 | 6,800 kW |
| 13 | Clear Lake | 2,500 kW |
| 14 | Shoshone Falls | 11,500 kW |
| 15 | Twin Falls | 52,897 kW |
| 16 | Milner | 59,448 kW |
| 17 | American Falls | 92,340 kW |

## 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 |

[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, 2017

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<br>Boise, ID 83702-5627<br>(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 (§ 232.405 of this chapter) 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 (§ 229.405 of this chapter) 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, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

IDACORP, Inc.:
Large accelerated filer _X_ Accelerated filer __ Non-accelerated filer __ (Do not check if a smaller reporting company)
Smaller reporting company __
Emerging growth company __

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. __

Idaho Power Company:
Large accelerated filer __ Accelerated filer __ Non-accelerated filer _X_ (Do not check if a smaller reporting company)
Smaller reporting company
Emerging growth company __

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. __

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, 2017):

| | | | |
|---|---|---|---|
| IDACORP, Inc.: | $ 4,258,357,592 | Idaho Power Company: | None |

Number of shares of common stock outstanding as of February 16, 2018:

| | |
|---|---|
| IDACORP, Inc.: | 50,392,360 |
| 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 2018 annual meeting of shareholders. |

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2018 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 |
| BCC | - | Bridger Coal Company, a joint venture of IERCo |
| BLM | - | U.S. Bureau of Land Management |
| CAA | - | Clean Air Act |
| $CO_2$ | - | Carbon Dioxide |
| CSPP | | Cogeneration and Small Power Production |
| CWA | - | Clean Water Act |
| EIM | - | Energy Imbalance Market |
| EIS | - | Environmental Impact Statement |
| EPA | - | U.S. Environmental Protection Agency |
| ESA | - | Endangered Species Act |
| FCA | - | Idaho Fixed Cost Adjustment |
| FERC | - | Federal Energy Regulatory Commission |
| FIP | - | Federal Implementation Plan |
| FPA | - | Federal Power Act |
| GAAP | - | Generally Accepted Accounting Principles |
| GHG | - | Greenhouse Gas |
| HCC | - | Hells Canyon Complex |
| Ida-West | - | Ida-West Energy Company, 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 |
| 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 |
| LTICP | - | IDACORP 2000 Long-term Incentive and Compensation Plan |
| 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 |
| NEPA | - | National Environmental Policy Act |
| NERC | - | North American Electric Reliability Corporation |
| NMFS | - | National Marine Fisheries Service |
| NOAA Fisheries | - | National Oceanic and Atmospheric Administration's 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 | - | Idaho Power Cost Adjustment |
| PCAM | - | Oregon Power Cost Adjustment Mechanism |
| PEIS | - | Programmatic Environmental Impact Statement |
| PURPA | - | Public Utility Regulatory Policies Act of 1978 |
| REC | - | Renewable Energy Certificate |
| RH BART | - | Regional haze - best available retrofit technology |
| RPS | - | Renewable Portfolio Standard |
| SEC | - | U.S. Securities and Exchange Commission |
| SCR | - | Selective catalytic reduction equipment |
| SMSP | - | Security Plan for Senior Management Employees |
| SO2 | - | Sulfur Dioxide |
| USFWS | - | U.S. Fish and Wildlife Service |
| WECC | - | Western Electricity Coordinating Council |

## 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, future events, or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "guidance," "intends," "potential," "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 U.S. 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, including the impact of settlement stipulations;
- the expense and risks associated with capital expenditures for infrastructure, and the regulatory authorization and timing of cost recovery for such expenditures through customer rates;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area and the loss or change in the business of significant customers, and their associated impacts on loads and load growth, and the availability of regulatory mechanisms that allow for timely cost recovery in the event of those changes;
- the impacts of economic conditions, including inflation, interest rates, supply costs, population growth or decline in the service area, the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and the collection of receivables;
- unseasonable or severe weather conditions, wildfires, drought, and other natural phenomena and natural disasters, including conditions and events associated with climate change, which affect customer demand, hydroelectric generation levels, repair costs, liability for damage caused by utility property, and the availability and cost of fuel for generation plants or purchased power to serve customers;
- advancement of self-generation or energy efficiency technologies that reduce Idaho Power's sale of electric power;
- 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;
- adoption of, changes in, and costs of compliance with laws, regulations, and policies relating to the environment, natural resources, and threatened and endangered species, and the ability to recover associated increased costs through rates;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River Basin, which may impact the amount of power generated by Idaho Power's hydroelectric facilities;
- the ability to acquire fuel, power, and transmission capacity under reasonable terms, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires (either at or caused by Idaho Power facilities), explosions, and mechanical breakdowns that may occur while operating and maintaining Idaho Power assets, 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, and regulatory fines and penalties;
- the increased costs and operational challenges associated with purchasing and integrating intermittent renewable energy sources into Idaho Power's resource portfolio;
- disruptions or outages of Idaho Power's generation or transmission systems or of any interconnected transmission system may cause Idaho Power to incur repair costs and purchase replacement power at increased costs;
- the ability to obtain debt and equity financing or refinance existing debt when necessary and on favorable terms, which can be affected by factors such as credit ratings, volatility or disruptions 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, increase costs of borrowing, and would require the posting of additional collateral to counterparties pursuant to credit and contractual arrangements;
- 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;
- 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;
- 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, regulations and orders, 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;
- 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 resulting operational changes through insurance or rates, or from third parties;
- the failure of information systems or the failure to secure data, failure to comply with privacy laws, security breaches, or the direct or indirect effect on the companies' business, operations or reputation resulting from cyber-attacks, terrorist incidents or the threat of terrorist incidents, and acts of war;
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement new technology solutions; and
- adoption of or changes in accounting policies and principles, changes in accounting estimates, and new U.S. 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, 2017, IDACORP had 1,972 full-time employees, 1,964 of whom were employed by Idaho Power, and 11 part-time employees, 9 of whom were employed by Idaho Power.

IDACORP’s other notable subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments, and 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).

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.

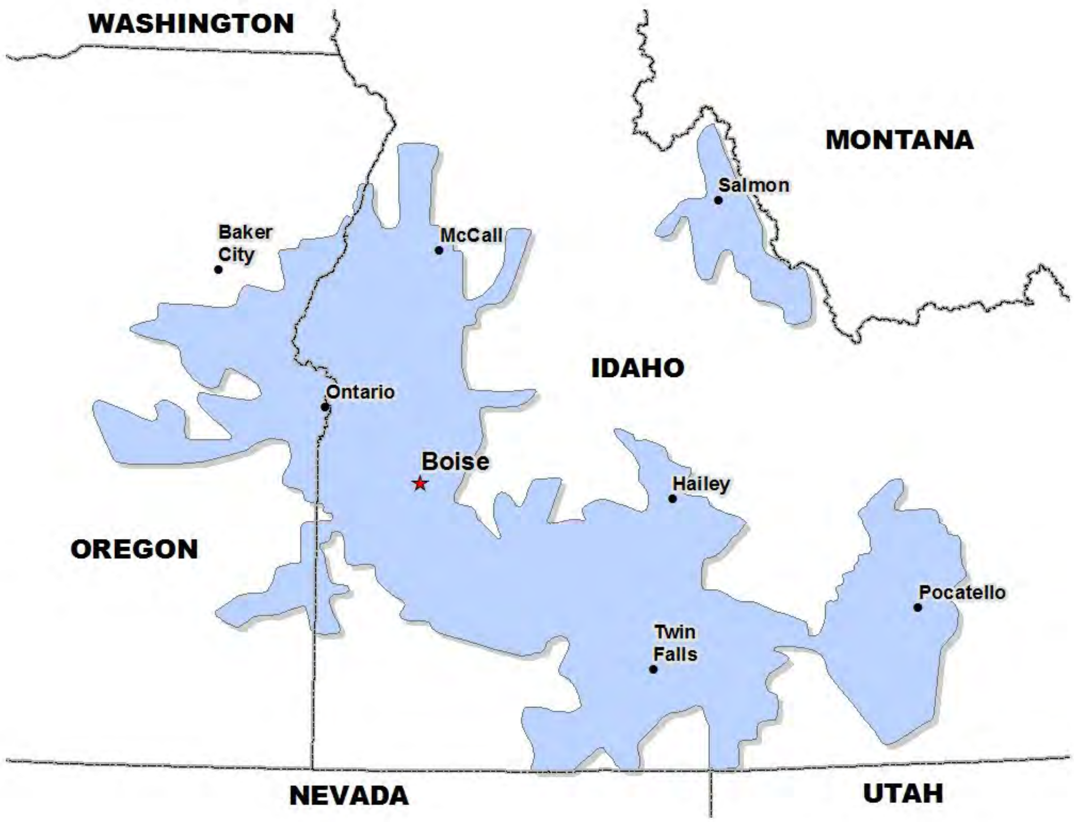
#### Available Information

IDACORP and Idaho Power make available free of charge on their websites their Annual Reports 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 more than 545,000 general business customers in southern Idaho and eastern Oregon as of December 31, 2017. Approximately 454,000 of these customers are residential. Idaho Power’s principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, health care, and winter recreation. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 72 cities in Idaho and 7 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 3 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 1.2 million.




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 (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its open access transmission tariff (OATT). 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 sometimes result 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 or accrued as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates or when otherwise directed to begin amortization by a regulator. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers that are expected to be refunded. 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 is committed to its focus on competitive total returns and generating long-term value for shareholders. IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business, as Idaho Power's regulated utility operations are the primary driver of IDACORP's operating results. IDACORP's board of directors has reviewed and affirmed its and Idaho Power's long-term strategy, which is focused on the following areas and related initiatives:

| Focus Areas | Initiatives |
|---|---|
| Grow to Enhance Financial Strength | - Enhance Business Development Initiatives<br>- Find New Revenue Opportunities<br>- Promote and Engage in Electrification<br>- Optimize Wholesale Transmission and Energy Sales |
| Improve the Core Business | - Upgrade Infrastructure for Growth, Technology Changes, Renewable Energy Integration, and Flexibility<br>- Evaluate and Control Expenditures and Continue Efficient Operations<br>- Use Technology to Enhance the Grid, System Reliability, and Safety<br>- Implement Rate Structures that are Fair and Reasonable to All Customers |
| Enhance Idaho Power's Brand | - Enhance Idaho Power's Customers' Experience and Interactions<br>- Continue Environmental Stewardship and Emission Reductions<br>- Continue Constructive Regulatory Relationships and a Regulatory Compliance Mindset |
| Focus on Safety & Employee Engagement | - Continue Idaho Power's Strong Focus on Safety and Reducing Injuries<br>- Focus on Employee Engagement and Leadership Development |

In executing the focus areas above, IDACORP seeks to balance the interests of shareholders, Idaho Power customers, employees, and other stakeholders. Idaho Power is working to continue to provide safe, affordable, reliable service to its customers from a diversified source of generation resources, with a continued commitment to strong, sustainable financial results and strong credit ratings.

**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 critical factors 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 continually evaluates the need to request changes to its retail electricity price structure to cover its operating costs and to earn a fair return on its investments. Idaho Power uses general rate cases, power cost adjustment mechanisms in Idaho and Oregon, a fixed cost adjustment (FCA) mechanism in Idaho, 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, 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, or that its costs will be recovered in advance of or at the same time as the costs are incurred.

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 amounts recorded under specific authorization from the IPUC or

OPUC but deferred for recovery or refund. 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 power cost adjustment mechanisms, FCA mechanism, and energy efficiency rider. The Idaho and Oregon power cost adjustment 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 or refund 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 most of its energy efficiency program costs through an energy efficiency rider on customer bills.

***Wholesale Markets*****:** 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 market power prices at the time when those resources are available. A reduction in either factor leads to lower off-system sales revenue.

***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, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| General business revenues (thousands of dollars) | | | |
| Residential | $ 552,333 | $ 514,954 | $ 512,068 |
| Commercial | 319,195 | 302,650 | 306,178 |
| Industrial | 195,124 | 182,590 | 182,254 |
| Irrigation | 150,030 | 156,505 | 164,403 |
| Provision for rate refund for sharing mechanism | — | — | (3,159) |
| Deferred revenue related to Hells Canyon Complex relicensing AFUDC | (10,706) | (10,706) | (10,706) |
| Total general business revenues | 1,205,976 | 1,145,993 | 1,151,038 |
| Off-system sales | 33,382 | 25,205 | 30,887 |
| Other | 105,535 | 88,155 | 85,580 |
| Total revenues | $ 1,344,893 | $ 1,259,353 | $ 1,267,505 |
| Energy sales (thousands of Megawatt-hour (MWh)) | | | |
| Residential | 5,355 | 5,004 | 4,977 |
| Commercial | 4,099 | 3,999 | 4,045 |
| Industrial | 3,346 | 3,243 | 3,196 |
| Irrigation | 1,771 | 1,950 | 2,047 |
| Total general business | 14,571 | 14,196 | 14,265 |
| Off-system sales | 2,136 | 1,186 | 1,254 |
| Total | 16,707 | 15,382 | 15,519 |

***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. However, alternative methods of generation, including customer-owned solar and other forms of distributed generation, compete with Idaho Power for sales to existing customers. Also, development of new technologies and services to help energy consumers manage energy in new ways could continue to alter demand for Idaho Power's electric energy. Idaho Power also competes with fuel distribution companies, including natural gas providers, in serving the energy needs of customers for space heating, water heating, and appliances.

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.

In return for agreeing to provide service to all customers within a defined service area, electric utilities are typically provided with an exclusive right to provide service in that service area. However, certain prescribed areas within Idaho Power's service area, such as municipalities or Native American Tribal reservations, may elect not to take service from Idaho Power and instead operate as a municipal electric utility or otherwise as a separate entity. In such cases, the entity would be required to purchase or otherwise obtain rights (such as by contract) to Idaho Power's distribution infrastructure within the municipal or other designated area. Idaho Power would have no responsibility for providing electric service to the municipal or separate entity, absent Idaho Power's voluntary execution of an agreement to provide that service. Separately, the Shoshone-Bannock Tribes, located in southeastern Idaho, have considered the adoption of a utility code applicable to electric utilities operating within the Shoshone-Bannock Tribal Reservation (Reservation). The tribal utility code, if adopted, could ultimately lead to Idaho Power's cessation of its historical provision of service to the Reservation and could result in either no or a limited electric service relationship with the Reservation, or could result solely in Idaho Power's sale of power to the Reservation pursuant to a power purchase agreement. Idaho Power estimates that the average load for the Reservation over the prior five years is approximately 14 Megawatts (MW).

**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, supply constraints, 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's power cost adjustment mechanisms 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 3,422 MW, set on July 7, 2017. On January 6, 2017, Idaho Power tied its highest all-time winter peak demand of 2,527 MW, which was originally 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 that follows shows Idaho Power’s total power supply for the last three years.

| | **Power Supply** | | | **Percent of Total Generation** | | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| | **(thousands of MWh)** | | | | | |
| Hydroelectric plants | 8,900 | 6,408 | 5,910 | 65% | 53% | 47% |
| Coal-fired plants | 3,284 | 4,045 | 4,676 | 24% | 33% | 37% |
| Natural gas-fired plants | 1,504 | 1,722 | 2,076 | 11% | 14% | 16% |
| Total system generation | 13,688 | 12,175 | 12,662 | 100% | 100% | 100% |
| Purchased power - cogeneration and small power production | 2,800 | 2,314 | 2,008 | | | |
| Purchased power - other | 1,442 | 2,023 | 1,784 | | | |
| Total purchased power | 4,242 | 4,337 | 3,792 | | | |
| Total power supply | 17,930 | 16,512 | 16,454 | | | |

***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 1,706 MW and annual generation of approximately 8.5 million MWh under median water conditions. The amount of water available for hydroelectric power generation depends on several factors—the amount of snowpack in the mountains upstream of Idaho Power’s hydroelectric facilities, upstream reservoir storage, springtime precipitation and temperatures, main river and tributary base flows, the condition of the Eastern Snake Plain Aquifer and its spring flow impact, summer time irrigation withdrawals and returns, and upstream reservoir regulation. Idaho Power actively participates in collaborative work groups focused on water management issues in the Snake River Basin, with the goal of preserving the long-term availability of water for use at Idaho Power’s hydroelectric projects on the Snake River.

In 2017, above normal winter and spring precipitation resulted in 8.9 million MWh of hydroelectric generation, a significant increase from the past two years. In 2016, low upstream reservoir carryover (primarily in the upper Snake River basin) resulted in reduced downstream flow releases. Additionally, although snowpack accumulation was near-normal on April 1, 2016, the snowpack melted earlier than usual. The combined effect was lower than median hydro production of 6.4 million MWh in 2016. In 2015, below-normal snow accumulation resulted in a lower than median hydro production of 5.9 million MWh. 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 greater reliance on other generation resources and power purchases. For 2018, Idaho Power estimates annual generation from its hydroelectric facilities to be between 7.5 million MWh and 9.5 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 agencies. 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, 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.

BCC supplies coal to the Jim Bridger power plant. IERCo, a wholly-owned subsidiary of Idaho Power, owns a one-third interest in BCC and PacifiCorp owns a two-third interest in BCC and is the operator of the Bridger Coal Mine. The mine operates under a long-term sales agreement that provides for delivery of coal through 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 2021 from the Black Butte mine located near the Jim Bridger plant. This contract supplements the BCC deliveries and provides another coal supply to fuel 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 (Valmy Plant). Idaho Power's existing coal inventory at the Valmy Plant is expected to meet Idaho Power's projected coal requirements at the plant through at least 2018. Idaho Power expects to be able to obtain future coal requirements through coal supply contracts. In 2017, Idaho Power established a process approved by the IPUC and OPUC for recovery of costs related to Idaho Power’s plan to end its participation in coal-fired operations at the Valmy Plant units 1 and 2 in 2019 and 2025, respectively. In both 2017 and 2016, the Valmy Plant provided 2 percent of Idaho Power's total generation. For additional information on the related settlement stipulations, see Part II, Item 7 – MD&A - "Regulatory Matters - Valmy Base Rate Adjustment Settlement Stipulations and Depreciation Rate Settlement Stipulations."

Portland General Electric Company is the operator of the Boardman power plant. Idaho Power believes that it has sufficient inventory and coal contracts to supply the Boardman plant with fuel through 2018. The Boardman plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Idaho Power expects to meet future coal needs through similar contracts. 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.

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 but generally contain the right for Idaho Power to extend the term. 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, 2017, approximately 6.5 million MMBtu of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through June 2019. 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 requirements, 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 2017 and 2016, Idaho Power purchased 0.9 million MWh and 1.4 million MWh of power through wholesale market purchases at an average cost of $26.32 per MWh and $24.80 per MWh, respectively. During 2017 and 2016, Idaho Power sold 2.1 million MWh and 1.2 million MWh of power in wholesale market sales, with an average price of $15.63 per MWh and $21.25 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:

- 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 ends in 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 contract term continues through 2020. Idaho Power has the right to renew the agreement for an additional five-year term.
- 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 ends in 2033.

PURPA Power Purchase Contracts: Idaho Power purchases power from PURPA projects as mandated by federal law. As of December 31, 2017, Idaho Power had contracts with on-line PURPA-related projects with a total of 1,114 MW of nameplate generation capacity, with an additional 5 MW nameplate capacity of projects projected to be on-line in 2018 and an additional 24 MW expected to be added in 2019. 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 following table:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| PURPA contract expense (in thousands) | $ 169,788 | $ 153,665 | $ 131,340 |
| MWh purchased under PURPA contracts (in thousands) | 2,800 | 2,314 | 2,008 |
| Average cost per MWh from PURPA contracts | $ 60.64 | $ 66.41 | $ 65.41 |

Pursuant to the requirements of PURPA, the IPUC and OPUC 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 area, 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 area 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 Idaho PCA mechanism, and the OPUC jurisdictional portion is recovered through base rates and an Oregon power cost recovery mechanism. Thus, the primary impact of high power purchase costs under PURPA contracts is on customer rates.
- OPUC jurisdictional regulations have generally provided for PURPA standard contract terms of up to 20 years.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 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 IPUC issued an order in August 2015 that revised the standard PURPA power purchase contract term for new contracts to a 2-year term from the previously required 20-year term for projects that exceed the size limitations for published avoided costs.
- The OPUC requires that Idaho Power pay the published avoided costs for solar PURPA qualifying facilities with a nameplate rating of 3 MW or less and all other types of projects with a nameplate rating of 10 MW or less. Idaho Power is required to negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations.

***Anticipated Participation in Western Energy Imbalance Market***: 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 balancing area. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The California ISO and PacifiCorp implemented an energy imbalance market in 2014 (Western EIM) under which the parties enabled their systems to interact for dispatch purposes. The Western EIM is intended to reduce the power supply 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 the Western EIM is voluntary and available to all balancing authorities in the western United States. Following an evaluation of the potential power supply cost savings and other advantages, system upgrade requirements, and estimated capital and ongoing operating costs, Idaho Power executed an agreement under which it intends to, subject to regulatory approval and other conditions, participate in the Western EIM. Idaho Power anticipates that it will commence participation in the Western EIM in April 2018. For information on regulatory proceedings related to costs associated with joining the Western EIM, see Part II, Item 7 – MD&A - "Regulatory Matters - Recovery of Costs for Anticipated Participation in Western Energy Imbalance Market."

**Transmission Services**

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located hundreds of miles away 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, the transmission grid covering much of western North America. Idaho Power provides wholesale transmission service for eligible transmission customers on a non-discriminatory basis. Idaho Power is a member of the WECC, the Northwest PowerPool, 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 1,000-mile, 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 2017 (2017 IRP). 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.

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.

The load forecast assumptions Idaho Power used in the 2017 IRP are included in the table below, together with the average annual growth rate assumptions used in the prior two IRPs. 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.

| | **5-Year Forecast** | | **20-Year Forecast** | |
|---|---|---|---|---|
| | **Annual Growth Rate: Retail Sales (Billed MWh)** | **Annual Growth Rate: Annual Peak (Peak Demand)** | **Annual Growth Rate: Retail Sales (Billed MWh)** | **Annual Growth Rate: Annual Peak (Peak Demand)** |
| 2017 IRP | 1.1% | 1.6% | 0.9% | 1.4% |
| 2015 IRP | 1.1% | 1.5% | 1.1% | 1.4% |
| 2013 IRP | 1.2% | 1.5% | 1.0% | 1.3% |

Idaho Power's 2017 IRP identifies its preferred resource portfolio and action plan. The IRP includes the completion of the Boardman-to-Hemingway 500-kV transmission line by 2026, the end of Idaho Power's participation in coal-fired operations at the North Valmy power plant units 1 and 2 in 2019 and 2025, respectively, and the early retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively, with no other new resource needs prior to 2026. However, as noted in the 2017 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third party development of renewable resources, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These and other uncertainties could result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions.

***Energy Efficiency and Demand Response Programs:*** Idaho Power’s energy efficiency and demand response portfolio is comprised of 24 programs. These energy efficiency programs target energy savings across the entire year, while the demand response programs target system demand reduction in the summer at times of peak loads. The 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 generation or transmission 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 electric heating, ventilation and cooling equipment, as well as energy efficient building techniques, 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 cycling of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through actions taken by business owners and operators; and
- membership in the Northwest Energy Efficiency Alliance, which supports market transformation efforts across the region.

In 2017, Idaho Power’s energy efficiency programs reduced energy usage by approximately 170,000 MWh. For 2017, Idaho Power had a demand response available capacity of approximately 394 MW. In 2017 and 2016, Idaho Power expended approximately $48 million and $43 million, respectively, on both 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 power cost adjustment mechanisms. Energy efficiency program expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings.

**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 impacts Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, the modification of system operations to accommodate environmental regulations, and the cost of acquiring and complying with permits and licenses. In addition to generally applicable regulations, Idaho Power's three coal-fired power plants, three natural gas combustion turbine power plants, and 17 hydroelectric generating plants are subject to a broad range of environmental requirements, including those related to air and water quality, waste materials, and endangered species. 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, particularly given the volume of existing and proposed regulations 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):

| | 2018 | 2019 - 2020 |
|---|---|---|
| **Capital expenditures:** | | |
| License compliance and relicensing efforts at hydroelectric facilities | $ 12 | $ 31 |
| Investments in equipment and facilities at thermal plants | 5 | 18 |
| **Total capital expenditures** | $ 17 | $ 49 |
| **Operating expenses:** | | |
| Operating costs for environmental facilities - hydroelectric | $ 21 | $ 41 |
| Operating costs for environmental facilities - thermal | 11 | 24 |
| **Total operations and maintenance** | $ 32 | $ 65 |

Idaho Power anticipates that finalization, implementation, or modification of a number of federal and state rulemakings and other proceedings addressing, among other things, greenhouse gases and endangered species, could result in substantial changes in operating and compliance costs, but Idaho Power is unable to estimate those changes in costs given the uncertainty associated with existing and potential future regulations. Idaho Power expects that it would seek to recover increases in costs through the ratemaking process. Beyond 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 potential early plant retirements cannot be fully recovered in rates on a timely basis.

Idaho Power monitors environmental requirements and assesses whether environmental control measures are or remain economically appropriate. Continued review of the economic appropriateness of further investments in coal-fired plants 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 Valmy Plant as a coal-fired resource.

In 2017, the IPUC and OPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for the Valmy Plant in connection with Idaho Power's plan to end its participation in the operation of unit 1 at the Valmy Plant by the end of 2019 and unit 2 by 2025. The plan to end Idaho Power's participation in operations of units 1 and 2 at the Valmy Plant was based primarily on the economics of operating the plant. The settlement stipulations are described in Part II, Item 7 - MD&A - "Regulatory Matters" in this report. Additionally, in light of the uncertainty resulting from pending environmental regulation and the substantial estimated cost of selective catalytic reduction equipment (SCR) installation, Idaho Power is assessing whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant.

***Voluntary $CO_2$ Intensity Reduction Goal:*** Idaho Power is engaged in voluntary greenhouse gas emissions (GHG) 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. The combination of effective utilization of hydroelectric projects, above average stream flows in some years, reduced usage of coal-fired facilities, the purchase of renewable energy, and the 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. Idaho Power achieved its initial reduction goal, as well as its extended goal, through 2015. Idaho Power's average $CO_2$ emissions intensity from company-owned resources for the 2010 through 2015 period was 21 percent below the 2005 $CO_2$ emissions intensity level.

In 2015, Idaho Power further extended and expanded the goal, seeking to reduce the company-owned resource portfolio average $CO_2$ emissions intensity to 15-20 percent below 2005 levels for the 2010-2017 period. As of the date of this report, Idaho Power achieved the reduction goal set in 2015, with carbon emissions intensity at 25 percent below the 2005 level, and further extended the current $CO_2$ emissions intensity reduction goal through 2020.

Idaho Power's estimated historic $CO_2$ emissions intensity from its generation facilities was as follows:

| | 2017 | 2016 | 2015 | 2014 | 2013 | 2012 | 2011 | 2010 |
|---|---|---|---|---|---|---|---|---|
| **Emissions Intensity (lbs $CO_2$/MWh)** | 894 | 934 | 945 | 945 | 929 | 867 | 864 | 1,066 |

**IDACORP FINANCIAL SERVICES, INC.**

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, 2017, the unamortized amount of IFS's portfolio was approximately $6 million ($165 million in gross tax credit investments, net of $159 million of accumulated amortization). IFS generated tax credits of $2.6 million in both 2017 and 2016 and $3.3 million in 2015. In 2017 and 2016, IFS received distributions related to fully-amortized affordable housing investments that reduced IDACORP's income tax expense by $1.1 million and $1.7 million, respectively.

**IDA-WEST ENERGY COMPANY**

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 approximately $10 million in 2017 and $8 million in both 2016 and 2015.

**EXECUTIVE OFFICERS OF THE REGISTRANTS**

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below (in alphabetical order), 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.

DARREL T. ANDERSON, 59

- President and Chief Executive Officer of IDACORP, Inc., May 2014 - present
- President and Chief Executive Officer of Idaho Power Company, January 2014 - present
- President and Chief Financial Officer of Idaho Power Company, January 2012 - December 2013
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 2009 - April 2014
- Member of the Boards of Directors of IDACORP, Inc. and Idaho Power Company since September 2013

BRIAN R. BUCKHAM, 39

- Senior Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company, February 2017 - present
- Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company, April 2016 - February 2017
- In-house legal counsel of IDACORP, Inc. and Idaho Power Company, April 2010 - March 2016

LISA A. GROW, 52

- Senior Vice President and Chief Operating Officer of Idaho Power Company, April 2016 - present
- Senior Vice President of Operations of Idaho Power Company, January 2016 - March 2016
- Senior Vice President - Power Supply of Idaho Power Company, October 2009 - December 2015

STEVEN R. KEEN, 57

- Senior Vice President - Chief Financial Officer, and Treasurer of IDACORP, Inc., May 2014 - present
- Senior Vice President - Chief Financial Officer, and Treasurer of Idaho Power Company, January 2014 - present
- Senior Vice President - Finance and Treasurer of Idaho Power Company, January 2012 - December 2013
- Vice President - Finance and Treasurer of IDACORP, Inc., June 2010 - April 2014

LONNIE KRAWL, 54

- Senior Vice President of Administrative Services and Chief Human Resources Officer of Idaho Power Company, April 2016 - present
- Senior Vice President of Administrative Services and Chief Information Officer of Idaho Power Company, January 2016 - March 2016
- Vice President and Chief Information Officer of Idaho Power Company, October 2013 - December 2015
- Director of Human Resources of Idaho Power Company, July 2009 - September 2013

JEFFREY L. MALMEN, 50

- Senior Vice President of Public Affairs of IDACORP, Inc. and Idaho Power Company, April 2016 - present
- Vice President of Public Affairs of IDACORP, Inc. and Idaho Power Company, October 2008 - March 2016

TESSIA PARK, 56

- Vice President of Power Supply of Idaho Power Company, January 2016 - present
- Director of Load Serving Operations of Idaho Power Company, September 2012 - December 2015

KEN W. PETERSEN, 54

- Vice President, Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, January 2014 - present
- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 2010 - December 2013

N. VERN PORTER, 58

- Vice President of Transmission & Distribution Engineering and Construction and Chief Safety Officer, April 2016 - present
- Vice President of Customer Operations of Idaho Power Company, January 2016 - March 2016
- Senior Vice President of Customer Operations of Idaho Power Company, April 2015 - December 2015
- Vice President of Idaho Power Company, January 2014 - April 2015
- Vice President of Delivery Engineering and Construction of Idaho Power Company, May 2012 - December 2013

ADAM RICHINS, 39

- Vice President of Customer Operations and Business Development of Idaho Power Company, March 2017 - Present
- General Manager of Customer Operations, Engineering and Construction, January 2014 - February 2017
- In-house legal counsel of Idaho Power Company, November 2010 - January 2014

## ITEM 1A. RISK FACTORS

IDACORP and Idaho Power operate in a highly regulated 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, including without limitation, in Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Matters Impacting Future Results" in this report, and information in other reports the companies file with the SEC, should be considered carefully when making any investment decisions relating to IDACORP or Idaho Power.

***State or federal regulators may not approve customer rates that provide timely or sufficient recovery of Idaho Power's costs or allow Idaho Power to earn a reasonable rate of return, which could cause IDACORP's and Idaho Power's financial condition and results of operations to be adversely affected.***

The prices that the IPUC and OPUC authorize Idaho Power to charge customers for its retail services, and the tariff rate that the FERC 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, liquidity, and financial condition. Idaho Power's ability to recover its costs and earn a reasonable rate of return can be affected by many regulatory factors, including the timing difference between when costs are incurred and when those costs are recovered in customers’ rates (often called "regulatory lag" in the utility industry), and differences between the costs embedded in rates and the amount of actual costs incurred. Idaho Power is often required to incur costs before the IPUC, OPUC, or FERC approves the recovery of those costs, such as construction costs for new facilities or power lines, the costs of compliance with legislative and regulatory requirements and the costs of damage from natural disasters. The IPUC, OPUC, and FERC may not allow Idaho Power to recover some or all of those costs on the basis that Idaho Power did not reasonably or prudently incur those costs or for other reasons. While rate regulation is premised on the assumption that rates established are fair, just, and reasonable, regulators have considerable discretion in applying this standard. Decisions are subject to judicial appeal, which could lead to further uncertainty in regulatory proceedings. In response to economic, political, legislative, public policy, and regulatory pressures, Idaho Power may be subject to rate increase moratoriums, rate reductions or refunds, limits on rate increases, and lower allowed rates of return on investments. 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. The IPUC and OPUC may adopt different methods of calculating the allocation of the total utility costs in their respective jurisdictions, resulting in certain costs excluded in both states. 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 capital expenditures for long-term projects expenses. Adverse outcomes in regulatory proceedings or significant regulatory lag may cause Idaho Power to record an impairment of its assets or otherwise adversely affect cash flows and earnings and result in lower credit ratings, reduced access to capital and higher financing costs, and reductions or delays in planned capital expenditures.

For additional information relating to Idaho Power's state and federal regulatory framework and 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 mechanisms may not function as intended and are subject to change, 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. 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 of the difference between these two amounts is deferred for future recovery from, or refund to, customers through rates. Volatility in power supply costs continues to be significant, in large part due to fluctuations in hydroelectric generation conditions and high costs for the purchase of renewable energy under mandatory long-term contracts. While the power cost adjustment mechanisms function to mitigate the potentially adverse impact on net income of power supply cost volatility, the mechanisms do not eliminate the cash flow impact of that volatility. When power costs rise above the level recovered in current retail rates, Idaho Power incurs the costs but recovery of those costs is deferred to a subsequent collection period, which can adversely affect Idaho Power’s operating cash flow and liquidity until those costs are recovered from customers. The fixed cost adjustment mechanism is a decoupling mechanism designed to remove Idaho Power's disincentive to invest in energy efficiency activities by allowing Idaho Power to charge residential and small commercial customers when it recovers less than the base level of fixed costs per customer that the IPUC authorized for recovery in the most recent general rate case. The power cost and fixed cost adjustment mechanisms are generally subject to change at the discretion of applicable state regulators, who could decide to modify or eliminate either mechanism in a manner that adversely impacts IDACORP's and Idaho Power's financial condition, cash flows, and results of operations.

***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.*** Growth in the number of customers and customers' use of electricity are affected by a number of factors, such as population growth or decline in Idaho Power's service area, expansion or loss of service area, changes in customer needs and expectations, adoption rates of energy efficiency measures, customer-generated power such as from rooftop solar panels, demand-side management requirements, regulation or deregulation, and adverse economic conditions. An economic downturn or recession could also negatively impact customer use and reduce revenues and cash flows, thus adversely affecting results of operations. Many electric utilities, including Idaho Power, have experienced a decline in usage per customer, in part attributable to energy efficiency activities. State or federal regulations may be enacted to encourage or require mandatory energy conservation or technological advances that increase energy efficiency, which could further reduce usage per customer. Also, changing customer needs and expectations could lead to lower customer satisfaction, reduced loyalty, difficulty in obtaining rate increases, and customers seeking alternative sources of energy and the unbundling of regulated electric service. If customers choose to generate their own energy, discontinue a portion or all service from Idaho Power, or replace electric power for heating with natural gas, demand for Idaho Power's energy may decline and adversely impact the affordability of its services for remaining customers. While Idaho Power has recently experienced a net growth in usage due to an increase in the number of customers, when adjusted for the impacts of weather, the average monthly usage on a per customer basis for Idaho residential customers has declined from 1,051 kWh in 2009 to 952 kWh in 2017. Rate mechanisms, such as the Idaho fixed cost adjustment, are designed to address the financial disincentive associated with promoting energy efficiency activities, but there is no assurance that the mechanism will result in full or timely collection of Idaho Power's fixed costs, which are currently collected in large part through the company's volume-based energy rates that are based on historical sales volume. Any undercollection of fixed costs would adversely impact revenues, earnings, and cash flows. The formation of municipal utilities or similar entities for distribution systems within Idaho Power's service area could also result in a load decrease. The loss of loads resulting from some of these events may result in IDACORP and Idaho Power modifying or eliminating large generation or transmission projects. This could in turn result in reduced revenues as well as write-downs or write-offs if regulators determine that the costs of the projects were incurred imprudently, which could have a material adverse impact on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

Conversely, if Idaho Power were to experience an unanticipated increase in the demand for energy through, for example, the rapid addition of new industrial and commercial customers or population growth in the service area, Idaho Power may be required to rely on higher-cost purchased power to meet peak system demand and may 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 the sales to the new customers, and Idaho Power is unable to secure timely and full rate relief to recover those increased costs, the resulting imbalance could have an adverse effect on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

***IDACORP's and Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather conditions and severe weather.*** 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, can also create significant seasonal changes in usage. Seasonality of revenues may be further impacted by Idaho Power's tiered rate structure, under which rates charged to customers are often higher during higher-load periods, such as hot summers and cold winters. 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, weather conditions and the timing and extent of precipitation can cause IDACORP's and Idaho Power's results of operations and financial condition to fluctuate seasonally, quarterly, and from year to year.

Changes in climate in Idaho Power's service area could also have significant physical effects, such as increased frequency and severity of storms, droughts, heat waves, fires, floods, snow loading, and other extreme weather events. These extreme weather events and their associated impacts can damage transmission, distribution, and generation facilities, causing service interruptions and extended outages, increasing supply chain costs and other operating and maintenance expenses, and limiting Idaho Power's ability to meet customer energy demand. Sustained drought conditions or decreased snow pack due to higher temperatures are likely to decrease power generation from hydroelectric plants. Variations in hydroelectric generation that increase Idaho Power's reliance on market purchases may lead to more costly power supply sources for its customers and reduce benefits from selling surplus hydroelectric power in the wholesale market. The price of power in the wholesale energy markets tends to be higher during periods of high regional demand that tends to occur with weather extremes, which may cause Idaho Power to purchase power in the wholesale market during peak price periods, increasing power supply costs. The costs of repair and replacing infrastructure or liability for personal injury or property damage from utility equipment that fails from significant weather and weather-related events may not be covered in full by insurance. Costs incurred as a result of such events might also not be recovered through customer rates if the costs incurred are greater than those allowed for recovery by regulators.

***New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could decrease revenues***. The increasing cost of energy in the electric utility industry has encouraged the development of new technologies for power generation, power storage, and energy efficiency. In particular, in recent years the cost of solar generation has decreased significantly, and there are federal and state regulations, laws and other incentives in place to help further reduce the cost of solar generation. There is potential that customer-owned 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, which in turn could require changes in the way Idaho Power manages its distribution systems. Additionally, considerable emphasis has been placed on energy efficiency, such as LED lighting and high-efficiency appliances. 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 adjust its rate design or maintain adequate regulatory mechanisms allowing for timely cost recovery, declining usage from customer-owned generation sources and energy efficiency would result in under-recovery of Idaho Power's costs and investment in infrastructure, and reduce revenues, which would impact IDACORP's and Idaho Power's financial condition and results of operations.

***Capital expenditures for infrastructure, risks associated with permitting and 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;
- defaults by contractors;
- equipment, engineering, and design failures;
- unexpected environmental and geological problems;
- the effects of adverse weather conditions;
- availability of financing;
- load forecasts;
- the ability to obtain and comply with permits and land use rights, and environmental constraints; and
- delays and costs associated with disputes and litigation with third parties.

The occurrence of any of these risks could cause Idaho Power to operate at reduced capacity levels, which in turn could reduce revenues, increase expenses, or cause Idaho Power to incur penalties. If Idaho Power is unable or unwilling to complete the permitting or 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. Further, if Idaho Power is unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads or if other resources become more economical, it may terminate those projects and, as alternatives, 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 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 purchase orders 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.

***Changes in legislation, regulation, and government policy may have a material adverse effect on IDACORP’s and Idaho Power’s business in the future.*** Changes in, and uncertainty with respect to, federal, state, and local legislation, regulation, and government policy could significantly impact IDACORP’s and Idaho Power’s businesses and the electric utility industry. Specific legislative and regulatory proposals and recently enacted legislation that could have a material impact on IDACORP and Idaho Power include, but are not limited to, tax reform, infrastructure renewal programs, and modifications to public company reporting requirements and environmental regulation. Further, the proposals and new legislation could have an impact on the rate of growth of Idaho Power’s customers and their willingness to expand operations and increase electric service requirements. IDACORP and Idaho Power are monitoring the implementation by federal, state, and local governmental authorities of various executive orders and are unable to predict whether and to what extent such actions will meaningfully change existing legislative and regulatory environments relevant to the companies, or if any such changes would have a net positive or negative impact on the companies. To the extent that such changes have a negative impact on the companies or Idaho Power’s customers, including as a result of related uncertainty, these changes may materially and adversely impact IDACORP’s and Idaho Power’s business, financial condition, results of operations, and cash flows.

***Changes in income tax laws and regulations, or differing interpretation or enforcement of applicable laws by the U.S. 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 income taxes. Amounts of income 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. In recent years, state regulatory mechanisms with income tax-related provisions (such as Idaho Power's October 2014 regulatory settlement stipulation with the IPUC), has 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 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 net income tax expense or benefit 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. In addition, Idaho Power uses the regulatory flow-through income tax accounting method as described in Note 1 - "Summary of Significant Accounting Policies" to the consolidated financial statements included in this report, and potential changes in income tax laws or interpretations may impact IDACORP's and Idaho Power's income taxes and reporting obligations differently than most other companies.

Due to the enactment of the tax reform act generally referred to as the "Tax Cuts and Jobs Act", which lowered the corporate federal income tax rate, IDACORP and Idaho Power expect the changes in income tax law to reduce annual income tax expense for both companies beginning in 2018. However, due to Idaho Power's use of flow-through income tax accounting which has historically reduced income tax expense and contributed to lower electricity rates for customers, the changes in federal income tax law may not reduce IDACORP's and Idaho Power's income tax expense as significantly as the income tax expense of some peers in the utility industry who use fully normalized income tax accounting or non-utility companies. The IPUC has ordered Idaho Power to record a regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in federal income tax law, and to file a report with the IPUC identifying and quantifying the income tax changes along with proposed tariff schedule changes. Idaho Power also filed an application with the OPUC requesting authority to defer for later ratemaking treatment the Oregon jurisdictional earnings in excess of the currently authorized Oregon jurisdictional rate of return on equity that may result from the Tax Cuts and Jobs Act as measured from the Company's annual Oregon Results of Operations. The OPUC Staff filed an application with the OPUC requesting authority to defer for later ratemaking treatment the difference between Idaho Power's current retail rates and its current retail rates inclusive of the impact of the Tax Cuts and Jobs Act. Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law may benefit Idaho Power customers and 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 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.*** IDACORP's and Idaho Power's operations are subject to a number of federal, state, and local environmental statutes, rules, and regulations relating to air and water quality, natural resources, renewable energy, and health and safety. Many of these laws and regulations 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. Idaho Power devotes significant resources to environmental monitoring, pollution control equipment, and mitigation projects to comply with existing and anticipated environmental regulations. However, it is possible that federal, state and local authorities could attempt to enforce more stringent standards, stricter regulation, and more expansive application of environmental regulations.

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. Compliance with environmental regulations can significantly increase capital spending, operating costs and plant outages, and can negatively affect the affordability of Idaho Power's services for customers. Idaho Power cannot predict with certainty the amount and timing of all future expenditures necessary to comply with, or as a result of liabilities under, these environmental laws and regulations, although Idaho Power expects the expenditures will be substantial. In some cases, the costs to obtain permits and ensure facilities are in compliance may be prohibitively expensive. If the costs of compliance with 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. 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.

The current presidential administration has issued a number of executive orders related to environmental matters designed to ease environmental regulation that the federal agencies are still implementing. However, the outcome of the Environmental Protection Agency's and other federal agencies' review of regulations covered by the executive orders is difficult to predict. Moreover, the executive orders and any resulting federal regulations could be affected by Congressional action and challenged in court. Further, state and local governmental authorities could choose to replace the federal regulations or bolster environmental compliance and enforcement efforts at the local level. Accordingly, Idaho Power may not realize any benefit from changes to federal environmental regulations, if any, resulting from the executive orders and, as of the date of this report, cannot predict whether and to what extent the orders could affect its operations and environmental-related expenditures. Idaho Power is not guaranteed timely or full recovery through customer rates of costs associated with environmental regulations, environmental compliance, and clean-up of contamination, and regulators may not grant prior approval of cost recovery. 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.

In addition, some environmental regulations are currently subject to litigation and not yet final. As a result of this uncertainty, strategies to comply with the regulations, including available control technologies or other allowed compliance measures, are unpredictable and Idaho Power cannot provide any assurance regarding the potential impacts these regulations would have on Idaho Power's operations or 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 2017, 65 percent of Idaho Power's electric power generation was from hydroelectric facilities. Due to Idaho Power’s heavy reliance on hydroelectric generation, factors such as precipitation and snowpack, the timing of run-off, 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 approach to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights 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 market power purchases; therefore, costs increase and opportunities for off-system sales are reduced, reducing revenues and potentially earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most (but not all) of the increase in net power supply costs caused by lower hydroelectric generation. The timing of recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, adversely affecting cash flows and liquidity.

***Obligations 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, including for the Hells Canyon Complex. 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 generation requirements. One 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 a water temperature management apparatus which, if required to be installed, would involve substantial costs to construct, operate, and maintain. Idaho Power may be unable to recover in full or in a timely manner the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Another significant issue related to the relicensing effort involves a dispute between the states of Idaho and Oregon regarding whether to reintroduce or establish spawning populations of fish species into Idaho waters. Idaho Power cannot predict whether and how Idaho and Oregon will negotiate a mutually agreeable approach or whether legal or regulatory action will ultimately be necessary for such resolution, nor can Idaho Power predict the outcome of any such proceedings. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, whether a new multi-year license will ultimately be issued, and whether the IPUC or

OPUC will allow recovery through rates of the substantial costs incurred in connection with the licensing process and subsequent compliance. 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.

***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 volatile and influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Natural gas transportation to Idaho Power's three 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 on satisfactory terms, or at all. There also can be no assurance that counterparties to the natural gas or coal supply agreements will fulfill their obligations to supply natural gas or coal, and they may experience financial or technical problems or unforeseeable events that inhibit their ability to deliver natural gas or coal. 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 or timely recover these increased costs through rates, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

***If the assumptions underlying coal mine reclamation at Bridger Coal Company and related forecast trust fund growth are materially inaccurate, Idaho Power's costs could be greater than anticipated or be incurred sooner than anticipated.*** Bridger Coal Company, a subsidiary of Idaho Power, uses both surface and underground methods to mine coal to be used for power generation at the Jim Bridger power plant. The federal Surface Mining Control and Reclamation Act and state laws and regulations establish operational, reclamation, bonding, and closure obligations and standards for mining of coal. Bridger Coal Company's estimate of reclamation liability and bonding obligations is reviewed periodically by Idaho Power's management committee and by government regulators. Idaho Power funds a trust to cover such projected mine reclamation costs. The trust funds are invested in debt and equity securities and poor performance of these investments would reduce the amount of funds available for their intended purpose, which could require Idaho Power to make additional cash contributions. If actual costs related to those obligations exceed estimates, government regulations relating to those obligations change significantly or unexpected cash funding obligations are required, IDACORP's and Idaho Power's results of operations and financial condition could be adversely affected.

***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, wildfires, 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, liability to third parties, 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. Further, the transmission system in Idaho Power's service area is constrained, limiting the ability to transmit electric energy within the service area and access electric energy from outside the service area 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, and the inability to access lower cost sources of electric energy.

Accidents, electrical contacts, fires, explosions, catastrophic failures, general system damage or dysfunction, uncontrolled release of water from hydroelectric dams, and other unplanned events related to Idaho Power's infrastructure would increase repair costs and may expose Idaho Power to liability for personal injury and property damage. Fires alleged to have been caused by Idaho Power's transmission, distribution, or generation infrastructure could also expose Idaho Power to claims for fire suppression costs and liability for personal injury or property damage, whether based on claims of negligence, trespass or otherwise. Idaho Power maintains insurance coverage for such operating and event risks, but insurance coverage is subject to the terms and limitations of the available policies and may not be sufficient to cover Idaho Power’s ultimate liability. If the amount of insurance is insufficient or otherwise unavailable, or if Idaho Power is unable to recover in rates the costs of any uninsured losses, IDACORP’s and Idaho Power’s financial condition, results of operations, or cash flows could be materially affected.

***Volatility or disruptions in the financial markets, failure of IDACORP or Idaho Power to satisfy conditions necessary for obtaining loans or issuing debt securities, and 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, and ability to execute on their strategic plans.*** IDACORP and Idaho Power use credit facilities, commercial paper markets, and long-term debt as significant sources of liquidity and funding for operating and capital requirements and debt maturities not satisfied by operating cash flow. The credit facilities represent commitments by the participating banks to make loans and issue letters of credit. However, the ability and obligation of the participating banks to make those loans and issue letters of credit is subject to specified conditions and volatility or disruptions in the financial markets could affect the companies' ability to obtain debt financing or draw upon or renew existing credit facilities. Idaho Power's ability to issue long-term debt is also subject to a number of conditions included in an indenture, and Idaho Power's ability to issue long-term debt and commercial paper is subject to the availability of purchasers willing to purchase the securities under reasonable terms or at all. Because of these limitations, IDACORP and Idaho Power may be unable to issue commercial paper or short-term or long-term debt at reasonable interest rates and terms or at all. Also, while the credit facilities represent a contractual obligation to make loans, one or more of the participating banks may default on their obligations to make loans under, or may withdraw from, the credit facilities.

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, capital expenditures, and debt maturities. 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, and Idaho Power's long-term debt has also been issued under an indenture that contains a number of financial covenants. The companies must also make specified representations in connection with request for loans and it is possible that they may be unable to do so at the time of such request, which would limit or eliminate the obligation of the banks to provide loans. Failure to maintain these representations and 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 limit their ability to pursue certain projects and adversely impact IDACORP's and Idaho Power's financial condition, results of operations, 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.*** 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 rate mechanisms, the effectiveness of management, resource risks and power supply costs, and other factors. 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, reduce the pool of potential lenders, increase borrowing costs under existing credit facilities, limit access to the commercial paper market, 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. If access to capital were to become significantly constrained or costs of capital increased significantly due to lowered credit ratings, prevailing industry conditions, regulatory constraints, the volatility of the capital markets or other factors, IDACORP's and Idaho Power's financial condition and results of operations could be adversely affected.

***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 hedge transactions 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 used for hedging 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. Certain of Idaho Power's hedging and derivative agreements may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in Idaho Power's credit ratings may lead to additional collateral posting requirements. 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 and security standards issued by the North American Electric Reliability Corporation and enforced by the FERC. 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 FERC, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council. Potential monetary and non-monetary penalties for a violation of FERC regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The FERC may take action to limit volatility in the energy market by imposing price limits or other market restrictions to control market-based rate sales, which could adversely affect the companies' financial results. The imposition of penalties on Idaho Power for its actual or alleged failure to comply with reliability and security requirements could also 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 has had an impact on the operation of Idaho Power's generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Idaho Power is generally obligated under federal law to purchase power from certain renewable energy projects, regardless of the then-current load demand, availability of lower cost generation resources, or wholesale energy market prices. This increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, which in turn increases power purchase costs and customer rates and impacts Idaho Power's ability to invest in additional generation. Increases in customer rates could make self-generation more financially attractive for customers, which could result in reduced net load and shifts in customer costs. 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. If Idaho Power is unable to timely recover those costs through its power cost adjustment mechanisms or otherwise, those increased costs may negatively affect IDACORP's and Idaho Power's results of operations, financial condition, and cash flows.

***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 or the failure to maintain sustained growth in pension investments over time could increase Idaho Power's plan costs and funding requirements related to the plans. As benefit costs continue to rise, there is no assurance that the state public utility commissions will continue to allow recovery. 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 means. 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, tax obligations, 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.

***IDACORP's and Idaho Power's activities are concentrated in one industry and in one region, which exposes it to risks from lack of diversification, regional economic conditions, and regional legislation and regulation.*** IDACORP and Idaho Power do not have diversified operations or sources of revenue. Idaho Power comprises the bulk of IDACORP's operations, and Idaho Power's business is concentrated solely in the electricity industry. Furthermore, Idaho Power's provision of electric service to retail customers is conducted exclusively in its southern Idaho and eastern Oregon service area. As a result, IDACORP's and Idaho Power's future performance will be affected by economic conditions, regulatory and legislative activity, and other events in its service area and in the electric power industry.

***The impacts of a retiring 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’s operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, engineering and design personnel, and generation plant operators, require extensive, specialized training. Idaho Power has experienced in recent years an above-average number of employee retirements and expects the increased level of retirement of its skilled workforce and persons in key positions will continue in 2018 and in the near-term. At December 31, 2017, approximately 23 percent of Idaho Power's employees were eligible for regular or early retirement under Idaho Power's defined benefit pension plan. This will require Idaho Power to attract, train, and retain new employees to help prevent a loss of institutional knowledge and avoid a skills gap. The loss of skills and institutional knowledge of experienced employees and the failure to hire and the costs associated with attracting, training, and retaining appropriately qualified employees to replace an aging and skilled workforce could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

***IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims*****.** From time to time in the normal course of business, IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other adverse consequences. These matters are subject to a number of uncertainties, and management is often unable to predict the outcome of such matters; resulting liabilities could exceed amounts currently reserved or insured against with respect to such matter. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have reputational impact and a short- or long-term negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their operational practices and procedures, which could also have a negative effect on their financial positions and results of operations.

***Acts or threats of terrorism, cyber attacks, data or physical security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations or the electric power grid could require significant expenditures, or result in claims against the companies, and 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, and public health and safety. 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. Cyber threats and attacks can have cascading impacts that unfold with increasing speed across networks, information systems and other technologies. Network, information systems and technology-related events, including those caused by us, such as process breakdowns, security architecture or design vulnerabilities, or by third parties, such as computer hackings, cyber attacks, computer viruses, worms or other destructive or disruptive software, denial of service attacks, malicious social engineering or other malicious activities, or any combination of the foregoing, or power outages, natural disasters, infectious disease outbreaks, terrorist attacks or other similar events, could result in a degradation or disruption of the products and services of the companies. These events, and governmental actions in response, could result in a material decrease in revenues and increase costs to protect, repair, and insure Idaho Power's assets and operate its business.

Federal regulators have stated that a number of organizations continue to seek opportunities to exploit potential vulnerabilities in the U.S. energy infrastructure and that those attacks have become increasingly sophisticated. Attacks on Idaho Power's infrastructure could result from acts of those organizations or other third parties as well as Idaho Power employees or contractors. At the same time, Idaho Power's energy infrastructure is becoming more reliant on network-based infrastructure. Idaho Power's operations require the continuous availability of information technology systems and network infrastructure, and in the normal course of business, Idaho Power collects sensitive and confidential customer and employee information and proprietary information of Idaho Power. Although Idaho Power actively monitors developments in cyber security, no security measures can completely shield Idaho Power's systems, infrastructure, and data from vulnerabilities to cyber attacks, intrusions, or other catastrophic events that could result in their failure or reduced functionality, and ultimately the potential loss of sensitive information or the loss of Idaho Power's ability to fulfill critical business functions and provide reliable electric power to customers. Any security breaches, such as misappropriation, misuse, leakage, falsification or accidental release or loss of information maintained in IDACORP's and Idaho Power's information technology systems, including customer data, could result in violations of privacy and other laws, financial loss to Idaho Power or to its customers, customer dissatisfaction, and significant litigation and penalty exposure, all of which could materially affect Idaho Power's 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 SEC 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 FERC could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles (GAAP) 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, 2017, the system also includes approximately 4,857 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 223 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,441 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 Part II - Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects” in this report.

Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are included in the table 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 | 11,500 | 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 | 9,300 | |
| Total Hydroelectric | 1,706,045 | |
| **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 | 3,591,398 | |

(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 one-third for Jim Bridger, 50 percent for North 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. Excluding Idaho Power's power generation facilities and substations, Idaho Power owns an additional 1,016,286 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.

Through Idaho Energy Resources Co., Idaho Power 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 nameplate capacity of 44 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) under the trading symbol "IDA". On February 16, 2018, there were 9,340 holders of record of IDACORP common stock and the closing stock price was $85.27 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 $113 million, $105 million, and $97 million in 2017, 2016, and 2015, 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. The IDACORP board of directors has 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. IDACORP's dividends during 2017 were 53 percent of actual 2017 earnings. 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.

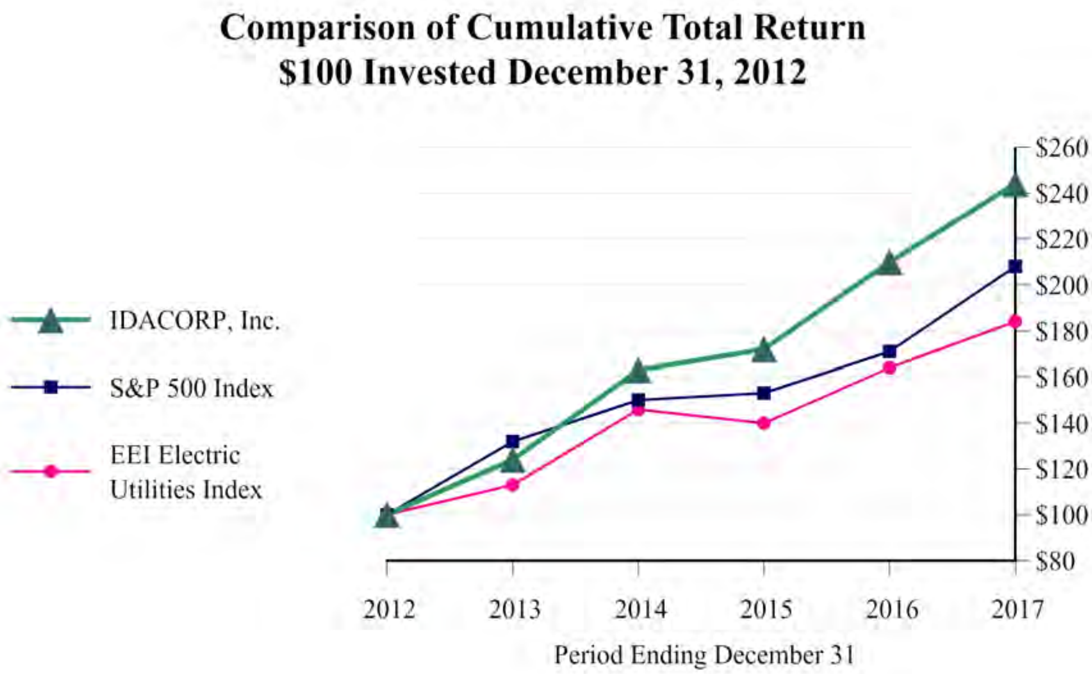
The following table shows the reported high and low sales price of IDACORP’s common stock and dividends paid for 2017 and 2016 as reported by the NYSE:

| | 2017 | | | 2016 | | |
|---|---|---|---|---|---|---|
| **Quarter** | **High** | **Low** | **Dividends paid per share** | **High** | **Low** | **Dividends paid per share** |
| 1st | $ 83.99 | $ 77.49 | $ 0.55 | $ 74.96 | $ 65.03 | $ 0.51 |
| 2nd | 90.67 | 82.08 | 0.55 | 81.36 | 69.83 | 0.51 |
| 3rd | 91.98 | 83.46 | 0.55 | 83.40 | 75.14 | 0.51 |
| 4th | 100.04 | 87.55 | 0.59 | 81.81 | 72.93 | 0.55 |

IDACORP did not repurchase any shares of its common stock during the fourth quarter of 2017.

**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, 2012, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.




Source: Bloomberg and EEI

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 |
|---|---|---|---|---|---|---|
| IDACORP | $ 100.00 | $ 123.51 | $ 162.59 | $ 172.25 | $ 209.83 | $ 244.01 |
| S&P 500 | 100.00 | 132.36 | 150.44 | 152.51 | 170.71 | 207.92 |
| EEI Electric Utilities Index | 100.00 | 113.01 | 145.67 | 139.99 | 164.39 | 183.66 |

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)**

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating revenues | $1,349,486 | $1,262,020 | $1,270,289 | $1,282,524 | $1,246,214 |
| Operating income | 304,351 | 271,776 | 282,097 | 253,696 | 291,742 |
| Net income attributable to IDACORP, Inc. | 212,419 | 198,288 | 194,679 | 193,480 | 182,417 |
| Diluted earnings per share | 4.21 | 3.94 | 3.87 | 3.85 | 3.64 |
| Dividends declared per share | 2.24 | 2.08 | 1.92 | 1.76 | 1.57 |
| | | | | | |
| **Financial Condition:** | | | | | |
| Total assets [1] | $6,045,405 | $6,289,897 | $6,023,314 | $5,701,037 | $5,347,380 |
| Long-term debt (including current portion) [1] | $1,746,123 | $1,745,678 | $1,726,474 | $1,599,686 | $1,599,139 |
| | | | | | |
| **Financial Statistics:** | | | | | |
| Times interest charges earned: | | | | | |
| Before tax[2] | 3.82 | 3.54 | 3.61 | 3.38 | 3.87 |
| After tax[3] | 3.30 | 3.15 | 3.12 | 3.19 | 3.06 |
| Book value per share[4] | $ 44.68 | $ 42.74 | $ 40.88 | $ 38.85 | $ 36.84 |
| Market-to-book ratio [5] | 204% | 188% | 166% | 170% | 141% |
| Payout ratio [6] | 53% | 53% | 50% | 46% | 43% |
| Return on year-end common equity [7] | 9.4% | 9.2% | 9.5% | 9.9% | 9.9% |

(1) Amounts in 2013-2014 adjusted to reflect IDACORP's 2015 adoption of Accounting Standards Update 2015-03, which required debt issuance costs be reported as reductions of long-term debt rather than as long-term assets on the consolidated balance sheets.

The financial statistics listed above are calculated in the following manner:

(2) 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.

(3) 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.

(4) Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

(5) 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 (4) above.

(6) Dividends paid per common share divided by diluted earnings per share.

(7) Net income attributable to IDACORP 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

In Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report, the general financial condition and results of operations for IDACORP and its subsidiaries and Idaho Power and its subsidiary 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.

### INTRODUCTION

IDACORP is a holding company 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 whose rates and other matters are regulated by the Idaho Public Utilities Commission (IPUC), Public Utility Commission of Oregon (OPUC), and Federal Energy Regulatory Commission (FERC). 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 is the parent of IERCo, a joint venturer in BCC, which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power. IDACORP’s other notable subsidiaries include IFS, an investor in affordable housing and other real estate investments; and Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the PURPA.

### EXECUTIVE OVERVIEW

IDACORP is committed to its focus on competitive total returns and generating long-term value for shareholders. IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business, as Idaho Power’s regulated electric utility operations are the primary driver of IDACORP’s operating results. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of IDACORP's and Idaho Power's achievements and recognitions during 2017 include:

- IDACORP achieved net income growth for a tenth consecutive year;
- IDACORP provided a 15 percent cumulative annual total shareholder return over the past three years, including share price appreciation and dividends paid, ranking in the 85th percentile among peer companies in the Edison Electric Institute (EEI) Electric Utilities Index;
- increased IDACORP's quarterly common stock dividend from $0.55 per share to $0.59 per share, as a part of a 97 percent increase in quarterly dividends approved over the last six years under the Board of Directors' objective to pay dividends at the upper end of the range from 50 percent to 60 percent of sustainable earnings;
- Idaho Power's customer count grew 2.0 percent, and sales volumes to industrial customers increased 3.2 percent in 2017 compared with 2016;
- Idaho Power achieved an all-time system peak demand of 3,422 MW on July 7, 2017, and on January 6, 2017, Idaho Power tied its highest all-time winter peak demand of 2,527 MW;
- Idaho Power ranked second in JD Power's Electric Business Customer Satisfaction Study in its West Midsize segment;
- established a process approved by the IPUC and OPUC for recovery of costs related to Idaho Power’s plan to end its participation in coal-fired operations at the North Valmy coal-fired power plant (Valmy Plant) units 1 and 2 in 2019 and 2025, respectively;
- Idaho Power executed on business optimization initiatives, focusing on improving operations and controlling expenditures, which have resulted in no significant increase to total other operations and maintenance (O&M) expenses over the past six years;
- Idaho Power reached milestones on key transmission projects as the U.S. Bureau of Land Management (BLM) issued a record of decision on the siting of the Boardman-to-Hemingway project and a final environmental assessment for the remaining transmission line segments of the Gateway West 500-kV transmission project;
- Idaho Power achieved Idaho Power's $CO_2$ emissions intensity reduction goal and extended the goal into future years; and
- in Idaho, Idaho Power reached agreement on a settlement stipulation that established the reasonableness of Hells Canyon Complex (HCC) relicensing costs incurred through December 2015.

**Summary of 2017 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, 2017, 2016, and 2015 (in thousands, except earnings per share amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Idaho Power net income | $ 206,347 | $ 189,242 | $ 190,983 |
| Net income attributable to IDACORP, Inc. | $ 212,419 | $ 198,288 | $ 194,679 |
| Average outstanding shares – diluted (000's) | 50,424 | 50,373 | 50,292 |
| IDACORP, Inc. earnings per diluted share | $ 4.21 | $ 3.94 | $ 3.87 |

The table below provides a reconciliation of net income attributable to IDACORP, Inc. for year ended December 31, 2017, from the year ended December 31, 2016 (items are in millions and are before tax unless otherwise noted):

| | | |
|---|---|---|
| **Net income attributable to IDACORP, Inc. - December 31, 2016** | | **$ 198.3** |
| Increase (decrease) in Idaho Power net income: | | |
| Customer growth, net of associated power supply costs and power cost adjustment mechanisms | 9.2 | |
| Usage per customer, net of associated power supply costs and power cost adjustment mechanisms | 9.9 | |
| FCA revenues | (12.1) | |
| Revenues per MWh, net of associated power supply costs and power cost adjustment mechanisms | 34.1 | |
| Transmission wheeling and other revenue | 11.9 | |
| O&M expenses | 2.2 | |
| Depreciation expense | (18.4) | |
| Other changes in operating revenues and expenses, net | (1.2) | |
| Increase in Idaho Power operating income | 35.6 | |
| Earnings of unconsolidated equity-method investments | (1.6) | |
| Non-operating income and expenses, net | (2.8) | |
| Income tax expense | (14.1) | |
| Total increase in Idaho Power net income | | 17.1 |
| IDACORP income in 2016 from legal settlement (net of tax) | | (3.7) |
| Other IDACORP changes (net of tax) | | 0.7 |
| **Net income attributable to IDACORP, Inc. - December 31, 2017** | | **$ 212.4** |

IDACORP's 2017 net income increased $14.1 million compared with 2016, primarily from higher net income at Idaho Power. Customer growth in 2017 contributed to an increase in Idaho Power's operating income of $9.2 million compared with 2016, as the number of Idaho Power customers grew by 2.0 percent over 2016. Warmer summer temperatures and colder winter temperatures during 2017 compared with 2016 led to increased sales volumes on a per-customer basis, primarily for residential customers using energy for heating and cooling. The increased residential sales volumes resulted in residential sales making up a larger portion of the sales mix and contributed to a greater proportion of residential sales in higher rate categories under Idaho Power's tiered rate structure. Higher levels of commercial and industrial activity in Idaho Power's service area also led to an increase in sales volumes on a per customer basis for commercial and industrial customers. Higher usage per customer in 2017 compared with 2016 increased Idaho Power's operating income by $9.9 million during that period. The FCA mechanism reduced operating income by $12.1 million during 2017 compared with 2016, as the increased usage per customer led to less FCA revenue needed to recover fixed costs. The Valmy Plant settlement stipulation described below in this MD&A, along with the residential sales changes noted above, led to a $34.1 million increase in operating income due to the resulting increase in revenues per MWh.

During 2017, Idaho Power benefited from an $11.9 million increase in transmission wheeling and other revenue compared with 2016. This change was primarily due to an increase in wheeling volumes, an increase in Idaho Power's OATT rates, and a new long-term wheeling agreement that became effective in July 2016.

In 2017, the IPUC and OPUC each approved settlement stipulations related to Idaho Power's plan to end its participation in coal-fired operations at the Valmy Plant by the end of 2025. The settlement stipulations resulted in increased general business revenues in 2017, increased net depreciation expense, and increased associated income tax expense, including plant-related flow-through tax adjustments. Most of the $34.1 million increase in "Revenues per MWh, net of associated power supply costs and power cost adjustment mechanisms" in the table above reflects the increase in general business revenues from the Valmy Plant settlement stipulations and most of the $18.4 million increase in "Depreciation expense" in the table above reflects the increase in depreciation expense. Compared with Idaho Power's estimate of what ongoing net income would have been without the settlement stipulations, the settlement stipulations are expected to increase after-tax net income by approximately $5 million on an annual basis. Idaho Power expects the ongoing annual benefit to net income from the Valmy Plant settlement stipulations to decline slightly each year through 2028, primarily due to the annual decline in Valmy Plant-related rate base, which is expected to be fully depreciated by December 31, 2028.

O&M expenses decreased $2.2 million in 2017 compared with 2016, primarily due to a $2.4 million benefit related to previously expensed energy efficiency rider-funded costs deemed to be prudently incurred as further discussed in "Regulatory Matters" in this MD&A, and a $2.7 million decrease in thermal O&M expenses due to lower generation at thermal plants. These decreases in O&M were partially offset by a $2.5 million increase in O&M related to a pending settlement stipulation in Idaho that established the reasonableness of HCC relicensing costs incurred through December 2015 as further discussed in "Regulatory Matters" in this MD&A.

Changes in non-operating income and expenses, net, reduced operating income by $2.8 million when compared with 2016, primarily related to a decrease in allowance for funds used during construction (AFUDC). In 2017, Idaho Power reduced AFUDC by $2.5 million related to the pending HCC settlement stipulation noted above.

Idaho Power's income tax expense was higher in 2017 compared with 2016, primarily due to higher pre-tax income and the $5.6 million flow-through benefit of tax deductible make-whole premiums that Idaho Power paid in connection with the early redemption of long-term debt in 2016. There were no early redemptions of long-term debt in 2017. These increases in income tax expense were partially offset by greater net flow-through income tax items at Idaho Power.

IDACORP's 2016 net income also included $3.7 million of income, net of tax, which was the result of a December 2016 settlement relating to the California energy market proceedings.

**2018 Initiatives and Strategy**

IDACORP and Idaho Power's strategy is focused on four strategic areas of growing to enhance financial strength, improving Idaho Power's core business, enhancing Idaho Power's brand, and focusing on safety and employee engagement. IDACORP's board of directors has reviewed and affirmed IDACORP's and Idaho Power's long-term strategy. In executing on these four strategic focus areas, IDACORP seeks to balance the interests of shareowners, Idaho Power customers, employees, and other stakeholders. Idaho Power is working to continue to provide safe, affordable, reliable service to its customers from a diversified source of generation resources, with a continued commitment to strong, sustainable financial results. For more information on the business strategy of the companies, see Part I, Item 1 – "Business - Business Strategy" in this report.

**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 a number of factors, and the impact of those factors is discussed in more detail below in this MD&A. To provide context for the discussion elsewhere in this report, some of the more notable factors include the following:

- ***Tax Cuts and Jobs Act:*** On December 22, 2017, the tax reform act generally referred to as the "Tax Cuts and Jobs Act" was signed into law, which lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. The majority of the law changes, including the rate reduction, became effective on January 1, 2018. IDACORP and Idaho Power expect the changes in income tax law to reduce annual income tax expense for both companies beginning in 2018. Due to Idaho Power's use of regulatory flow-through income tax accounting which has historically reduced income tax expense and contributed to lower electricity rates for customers, the changes in federal income tax law may not reduce IDACORP's and Idaho Power's income tax expense as significantly as some peers in the utility industry who use fully normalized income tax accounting or non-utility companies. Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law may benefit Idaho Power customers and affect IDACORP's and Idaho Power's financial condition and results of operations. The method through which potential cost savings may be accrued for the benefit of customers, including potential reductions to customer rates and to regulatory deferrals, will require approval from the IPUC and OPUC. Refer to "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings.

- ***Regulation of Rates and Cost Recovery:*** The price that Idaho Power is authorized to charge for its electric and transmission service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Those rates are established by state regulatory commissions and the FERC, and are intended to allow Idaho Power an opportunity to recover its expenses and earn a reasonable return on investment. Because of the significant impact of ratemaking decisions, and in pursuit of its goal of advancing a purposeful regulatory strategy, Idaho Power focuses on timely recovery of its costs through filings with the company's regulators, working to put in place innovative regulatory mechanisms, and on the prudent management of expenses and investments. Idaho Power has a regulatory settlement stipulation in Idaho that includes provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent return on year-end equity in the Idaho jurisdiction (Idaho ROE). The settlement stipulation also provides for the potential sharing between the company and customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. The specific terms of the settlement stipulation are described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. During 2018, Idaho Power will continue to assess the need to file a general rate case to reset base rates.

- ***Economic Conditions and Loads:*** Economic conditions impact consumer demand for electricity and revenues, 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. In recent years, Idaho Power has seen growth in the number of customers in its service area. In 2017, Idaho Power's customer count grew by 2.0 percent, and employment in Idaho Power's service area grew by approximately 3.7 percent based on Idaho Department of Labor preliminary December 2017 data. Idaho Power expects its number of customers to continue to increase in the foreseeable future. Idaho Power has in recent years supported State of Idaho-coordinated efforts to promote economic development with an emphasis on attracting industrial and commercial customers to its service area.

  In June 2017, Idaho Power filed its Integrated Resource Plan (2017 IRP), Idaho Power's long-term forecast of loads and resources. The load forecast assumptions Idaho Power used in the 2017 IRP are included in the table below. For comparison purposes, the analogous average annual growth rates used in the prior two IRPs are included.

| | **5-Year Forecast** | | **20-Year Forecast** | |
|---|---|---|---|---|
| | **Annual Growth Rate: Retail Sales (Billed MWh)** | **Annual Growth Rate: Annual Peak (Peak Demand)** | **Annual Growth Rate: Retail Sales (Billed MWh)** | **Annual Growth Rate: Annual Peak (Peak Demand)** |
| 2017 IRP | 1.1% | 1.6% | 0.9% | 1.4% |
| 2015 IRP | 1.1% | 1.5% | 1.1% | 1.4% |
| 2013 IRP | 1.2% | 1.5% | 1.0% | 1.3% |

- ***Rate Base Growth and Infrastructure Investment:*** As noted above, the rates established by the IPUC and OPUC are determined so as to provide an opportunity for Idaho Power to recover authorized operating expenses and earn a reasonable return on “rate base.” Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the IPUC and OPUC. In recent years, Idaho Power has been pursuing significant enhancements to its utility infrastructure, including major ongoing transmission projects such as the Boardman-to-Hemingway and Gateway West projects, 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, and the company is undertaking a significant relicensing effort for the HCC, its largest hydroelectric generation resource. Idaho Power expects to include completed capital projects in its next general rate case or, in circumstances where appropriate, a single-issue rate case for individual projects with a significant capital cost. Depending on the outcome of the regulatory process and items such as the rate of return authorized by the IPUC and OPUC, this growth in rate base has the potential to increase Idaho Power's revenues and earnings.

- ***Weather Conditions:*** Weather and agricultural growing conditions have a significant impact on Idaho Power's energy 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 extent 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. Much of the adverse or favorable impact of weather on sales of energy to residential and small commercial customers is mitigated through the Idaho FCA mechanism.

Further, as Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity, precipitation levels impact the mix of Idaho Power's generation resources. When hydroelectric generation is reduced, Idaho Power must rely on more expensive generation sources and purchased power. When favorable hydroelectric generating conditions exist for Idaho Power, they also may exist for other Pacific Northwest hydroelectric facility operators, lowering regional wholesale market prices and impacting the revenue Idaho Power receives from off-system sales of its excess power. Much of the adverse or favorable impact of this volatility is addressed through the Idaho and Oregon power cost adjustment mechanisms.

- ***Mitigation of Impact of Fuel and Purchased Power Expense:*** In addition to hydroelectric generation, Idaho Power relies significantly on natural gas and coal 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. Recently, low natural gas prices have made operation of Idaho Power's natural gas power plants more economical, resulting in increased operation of those plants and decreased operation of coal-fired plants. 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. The Idaho and Oregon power cost adjustment mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power.

- ***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, the North American Electric Reliability Corporation, and Western Electricity Coordinating Council. Compliance with these requirements directly influences Idaho Power's operating environment and affects Idaho Power's operating costs. Environmental laws and regulations, in particular, may 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. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade.

- ***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 its hydroelectric projects. Also, Idaho Power is involved in renewing its long-term federal license for the HCC, its largest hydroelectric generation source. Given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial. Idaho Power cannot currently determine the terms of, and costs associated with, any resulting long-term license.

## 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 2017 are compared with 2016 and the results for 2016 are compared with 2015.

### 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, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| General business sales | 14,571 | 14,196 | 14,265 |
| Off-system sales | 2,136 | 1,186 | 1,254 |
| Total energy sales | 16,707 | 15,382 | 15,519 |
| Hydroelectric generation | 8,900 | 6,408 | 5,910 |
| Coal generation | 3,284 | 4,045 | 4,676 |
| Natural gas and other generation | 1,504 | 1,722 | 2,076 |
| Total system generation | 13,688 | 12,175 | 12,662 |
| Purchased power | 4,242 | 4,337 | 3,792 |
| Line losses | (1,223) | (1,130) | (935) |
| Total energy supply | 16,707 | 15,382 | 15,519 |

***Sales Volume and Generation:*** In 2017, general business sales volumes increased 375 thousand MWh, or 3 percent, compared with the prior year. Customer growth contributed to increased sales volumes in 2017 compared with 2016, with the number of Idaho Power's customers growing by 2.0 percent in 2017 compared with 2016. In addition, cooling degree days in 2017 were 34 percent higher than 2016, which increased the use of electricity for cooling purposes. Heating degree days in 2017 were 18 percent higher than 2016, which increased the use of electricity for heating purposes. Increased commercial and industrial activity in Idaho Power's service area led to an increase in sales volumes for commercial and industrial customers. These increases in sales volumes were partially offset by a 9 percent decrease in sales volumes for irrigation customers in 2017 compared with 2016. Precipitation in the Idaho Power service area was significantly higher in 2017 compared with 2016, which reduced usage by irrigation customers, particularly in the first six months of 2017.

Off-system sales volumes increased 950 thousand MWh, or 80 percent, during 2017 compared with 2016 due primarily to increased hydroelectric generation exceeding the increased general business sales, resulting in more energy available for off-system sales. During 2017, hydroelectric generation comprised 65 percent of Idaho Power's total system generation compared with 53 percent during 2016. Generation from Idaho Power's hydroelectric plants increased due to significantly greater precipitation in 2017 compared with 2016. Precipitation in Boise, Idaho was 77 percent higher in 2017 compared with 2016.

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 power cost adjustment mechanisms, which are described later in this MD&A.

***General Business Revenues*:** The table below presents Idaho Power's general business revenues (in thousands), MWh sales (in thousands), and number of customers for the last three years.

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| Revenue | | | |
| Residential | $ 552,333 | $ 514,954 | $ 512,068 |
| Commercial | 319,195 | 302,650 | 306,178 |
| Industrial | 195,124 | 182,590 | 182,254 |
| Irrigation | 150,030 | 156,505 | 164,403 |
| Total | 1,216,682 | 1,156,699 | 1,164,903 |
| Provision for sharing | — | — | (3,159) |
| Deferred revenue related to HCC relicensing AFUDC[1] | (10,706) | (10,706) | (10,706) |
| Total general business revenues | $ 1,205,976 | $ 1,145,993 | $ 1,151,038 |
| Volume of Sales (MWh) | | | |
| Residential | 5,355 | 5,004 | 4,977 |
| Commercial | 4,099 | 3,999 | 4,045 |
| Industrial | 3,346 | 3,243 | 3,196 |
| Irrigation | 1,771 | 1,950 | 2,047 |
| Total MWh sales | 14,571 | 14,196 | 14,265 |
| Number of customers at year-end | | | |
| Residential | 453,605 | 444,431 | 436,102 |
| Commercial | 70,411 | 69,344 | 68,352 |
| Industrial | 119 | 121 | 118 |
| Irrigation | 20,932 | 20,638 | 20,293 |
| Total customers | 545,067 | 534,534 | 524,865 |

[1] As part of its January 30, 2009 general rate case order, the IPUC is allowing Idaho Power to recover the allowance for funds used during construction (AFUDC) on construction work in progress related to the HCC relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting approximately $10.7 million annually in the Idaho jurisdiction for AFUDC on HCC construction work in progress, but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs are placed in service.

Changes in rates, changes in customer demand, and changes in FCA revenues are the primary causes for 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 influences on changes in customer demand for electricity are growth in number of customers, weather, economic conditions, and energy efficiency. Rates are seasonally adjusted, providing for higher rates during the summer peak load season, and residential customer rates are tiered, providing for higher rates based on higher levels of usage. The seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings. Precipitation levels and the timing of precipitation during the agricultural growing season also affect sales to customers who use electricity to operate irrigation pumps. Extreme temperatures increase sales to customers who use electricity for cooling and heating, while moderate temperatures decrease sales. For purposes of illustration, Boise, Idaho, weather-related information for the last three years is presented in the following table.

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| | **2017** | **2016** | **2015** | **Normal[2]** |
| Heating degree-days[1] | 5,655 | 4,807 | 4,694 | 5,514 |
| Cooling degree-days[1] | 1,341 | 1,001 | 1,280 | 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 area, the greater Boise area has the majority of Idaho Power's customers.

[2] Normal heating degree-days and cooling degree-days elements are, by convention, the arithmetic mean of the elements computed over 30 consecutive years. The annual normal amounts are the sum of the 12 monthly normal amounts. These normal amounts are computed by the National Oceanic and Atmospheric Administration.

General Business Revenues - 2017 Compared with 2016: General business revenue increased $60.0 million in 2017 compared with 2016. The factors affecting general business revenues during the period are discussed below:

- Rates: Rate changes, including the revenue accruals provided for in the Valmy settlement stipulation, increased general business revenue by $39.8 million for 2017 compared with 2016. In the second quarter of 2017, the IPUC and OPUC each approved settlement stipulations related to Idaho Power’s plan to end its participation in coal-fired operations at the Valmy Plant by the end of 2025, which increased general business revenue collections and general business revenue accruals for 2017 compared with 2016. Colder winter temperatures in early 2017 and warmer summer temperatures during the third quarter of 2017 resulted in residential sales making up a larger portion of the sales mix and led to a greater proportion of residential sales in higher rate categories in Idaho Power's tiered rate structure in 2017 compared with 2016.

- Customers: Customer growth of 2.0 percent increased general business revenue by $12.1 million in 2017 compared with 2016.

- Usage: Higher usage (on a per customer basis), primarily by residential, industrial, and commercial customers increased general business revenue by $20.1 million in 2017 compared with 2016. Increased usage was primarily the result of warmer summer temperatures and colder winter temperatures in Idaho Power's service area, which increased usage by residential customers for cooling and heating. Cooling degree days and heating degree days were significantly higher in 2017 compared with 2016. These increases in usage were partially offset by an 11 percent decrease in usage per irrigation customer due to increased precipitation in Idaho Power's service area during 2017 compared with 2016, particularly in the first six months of 2017. Greater customer participation in energy efficiency programs, resulting in decreased usage, partially offset the increase in total usage during 2017 compared with 2016.

- Idaho FCA Revenue: The FCA mechanism adjusts revenue each year to collect, or refund, the difference between the authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. Higher usage (on a per customer basis) by residential and small general service customers during 2017 compared with 2016, decreased the amount of FCA revenue accrued by $12.1 million for 2017 compared with 2016. Idaho Power accrued $18.2 million of FCA revenue in 2017 compared with $30.3 million of FCA revenue in 2016.

General Business Revenues - 2016 Compared with 2015: General business revenue decreased $5.0 million in 2016 compared with 2015. The factors affecting general business revenues during the period are discussed below:

- Rates: Rate changes decreased general business revenue by $3.9 million in 2016 compared with 2015, primarily due to a decrease in the recovery of power cost adjustment amounts in 2016 compared with 2015. The recovery of power cost adjustment amounts in rates has no effect on operating income as it is amortized into expense in the same period it is recovered through rates.

- Customers: Customer growth of 1.8 percent increased general business revenue by $15.6 million in 2016 compared with 2015.

- Usage: Lower usage (on a per customer basis), primarily by irrigation, commercial, and residential customers, decreased general business revenue by $21.3 million in 2016 compared with 2015. Winter temperatures in 2016 were slightly colder than 2015, but milder summer temperatures in 2016 compared with 2015 led to lower sales volumes. A shorter irrigation season due to a later start in 2016 compared with 2015 resulted in lower usage per irrigation customer in 2016 compared with 2015. Greater customer participation in energy efficiency programs also contributed to lower usage during 2016 compared with 2015.

- Sharing: Idaho Power's sharing mechanism is associated with an 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. During 2015, Idaho Power recorded a total of $3.2 million as a provision against current revenue related to the sharing mechanism. In 2016, no such sharing provision was recorded because Idaho Power's Idaho ROE did not exceed 10.0 percent.

- Idaho FCA Revenue: Partially offsetting lower usage per customer, the Idaho FCA mechanism increased revenues by $1.4 million in 2016 compared with 2015. Idaho Power accrued $30.3 million of Idaho FCA revenues in 2016, compared with $28.9 million in 2015.

***Off-System Sales*:** Off-system sales consist primarily of opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years (in thousands, except for MWh amounts).

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Revenue | $ 33,382 | $ 25,205 | $ 30,887 |
| MWh sold | 2,136 | 1,186 | 1,254 |
| Revenue per MWh | $ 15.63 | $ 21.25 | $ 24.63 |

Off-System Sales - 2017 Compared with 2016: For 2017, off-system sales revenue increased by $8.2 million, or 32 percent compared with 2016 as generation from Idaho Power's hydroelectric plants increased due to significantly greater precipitation in 2017 compared with 2016. The increase in hydroelectric generation resulted in more energy available for off-system sales in 2017 compared with 2016. The average price of off-system sales was 26 percent lower for 2017 compared with 2016, as an increase in output from hydroelectric resources in the northwest United States region due to increased precipitation during the period, as well as additional output from new wind and solar projects throughout the region, increased surplus power available for sale and decreased wholesale power market prices.

Off-System Sales - 2016 Compared with 2015: Off-system sales revenue decreased by $5.7 million, or 18 percent in 2016 compared with 2015. Off-system sales volumes decreased 5 percent in 2016 compared with 2015 as lower wholesale market prices reduced the economic benefits of operating Idaho Power's non-hydroelectric generation facilities for off-system sales. The average price of off-system sales in 2016 was 14 percent lower compared with 2015.

***Other Revenues*:** The table below presents the components of other revenues for the last three years (in thousands).

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Transmission services and other | $ 66,294 | $ 54,401 | $ 55,048 |
| Energy efficiency | 39,241 | 33,754 | 30,532 |
| Total other revenues | $ 105,535 | $ 88,155 | $ 85,580 |

Other Revenues - 2017 Compared with 2016: Other revenues increased $17.4 million, or 20 percent, in 2017 compared with 2016. The increase was largely due to an increase in wheeling volumes, an increase in Idaho Power's OATT rates, and a new long-term wheeling agreement that became effective in July 2016, all of which increased revenues in 2017 compared with 2016. Also, greater customer participation in energy efficiency programs increased other revenues and corresponding expenses by $5.5 million in 2017 compared with 2016.

Most energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from, or obligation to, customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected. At December 31, 2017, Idaho Power's energy efficiency rider balances were a $0.4 million regulatory liability in the Idaho jurisdiction and a $6.3 million regulatory asset in the Oregon jurisdiction. As described in Note 3 - "Regulatory Matters" to the consolidated financial statements in this report, the approved net increase in Idaho power cost adjustment (PCA) rates, effective for the 2017-2018 PCA collection period from June 1, 2017, to May 31, 2018, included a $13.0 million refund of previously collected Idaho energy efficiency rider funds.

Other Revenues - 2016 Compared with 2015: Other revenues increased $2.6 million, or 3 percent, in 2016 compared with 2015. Greater customer participation in energy efficiency programs increased other revenues and corresponding expenses in 2016 compared with 2015. 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. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from, or obligation to, customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that

Idaho Power has spent more than it has collected. At December 31, 2016, Idaho Power's energy efficiency rider balances were a $5.6 million regulatory asset in the Oregon jurisdiction and a $10.7 million regulatory liability in the Idaho jurisdiction.

***Purchased Power*:** The table below presents Idaho Power's purchased power expenses and volumes for the last three years (in thousands, except for MWh amounts).

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Expense | | | |
| PURPA contracts | $ 169,788 | $ 153,665 | $ 131,340 |
| Other purchased power (including wheeling) | 72,179 | 85,040 | 88,430 |
| Demand response incentive payments | 6,983 | 7,059 | 6,701 |
| Total purchased power expense | $ 248,950 | $ 245,764 | $ 226,471 |
| MWh purchased | | | |
| PURPA contracts | 2,800 | 2,314 | 2,008 |
| Other purchased power | 1,442 | 2,023 | 1,784 |
| Total MWh purchased | 4,242 | 4,337 | 3,792 |
| Cost per MWh from PURPA contracts | $ 60.64 | $ 66.41 | $ 65.41 |
| Cost per MWh from other sources | $ 50.05 | $ 42.04 | $ 49.57 |
| Weighted average - all sources (excluding demand response incentive payments) | $ 57.04 | $ 55.04 | $ 57.96 |

Idaho Power is required by federal 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. The intermittent, non-dispatchable nature of the PURPA generation 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 its excess power in the wholesale power market at a significant loss. The other 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 power cost adjustment mechanisms.

Purchased Power - 2017 Compared with 2016: Purchased power expense increased $3.2 million, or 1 percent, in 2017 compared with 2016, primarily due to an increase in generation provided by PURPA solar contracts. The increase in PURPA volumes was partially offset by decreases in costs per MWh. Other purchased power expense decreased $12.9 million, or 15 percent, as abundant hydroelectric generation in 2017 compared with 2016 reduced the need for market purchases to meet load requirements.

Purchased Power - 2016 Compared with 2015: Purchased power expense increased $19.3 million, or 9 percent, in 2016, compared with 2015. The increase was due primarily to increased volumes purchased from both PURPA and non-PURPA sources attributable largely to lower market prices at times that encouraged market purchases rather than operating some generating units. Volume increases were partially offset by lower non-PURPA wholesale market prices.

***Fuel Expense*:** The table below presents Idaho Power's fuel expenses and thermal generation for the last three years (in thousands, except per MWh amounts).

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Expense | | | |
| Coal [1] | $ 107,894 | $ 137,689 | $ 131,286 |
| Natural gas[2] | 37,935 | 41,802 | 54,945 |
| Total fuel expense | $ 145,829 | $ 179,491 | $ 186,231 |
| MWh generated | | | |
| Coal [1] | 3,284 | 4,045 | 4,676 |
| Natural gas[2] | 1,504 | 1,722 | 2,076 |
| Total MWh generated | 4,788 | 5,767 | 6,752 |
| Cost per MWh - Coal | $ 32.85 | $ 34.04 | $ 28.08 |
| Cost per MWh - Natural gas | 25.22 | 24.28 | 26.47 |
| Weighted average, all sources | $ 30.46 | $ 31.12 | $ 27.58 |

(1) 2015 excludes 147 MWh of generation from the Jim Bridger power plant for which costs were capitalized during feasibility testing of capital projects under contemplation.
(2) Includes a negligible amount of expense and generation related to the Salmon diesel-fired generation plant.

The majority of the fuel for Idaho Power's jointly-owned coal-fired plants is purchased through long-term contracts, including purchases from BCC, a one-third owned joint venture of IERCo. The price of coal from BCC is subject to fluctuations in mine operating expenses, geologic conditions, and production levels. BCC supplies up to two-thirds of the coal used by the Jim Bridger plant. Natural gas is mainly purchased on the regional wholesale spot market at published index prices. 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 - 2017 Compared with 2016: Fuel expense decreased $33.7 million, or 19 percent, in 2017 compared with 2016, due primarily to increased output from Idaho Power's hydroelectric plants, which reduced utilization of gas and coal generation. Generation from the hydroelectric plants increased 39 percent during 2017 compared with 2016.

Fuel Expense - 2016 Compared with 2015: Fuel expense decreased $6.7 million, or 4 percent, in 2016 compared with 2015, due primarily to decreased output from coal-fired plants and natural gas plants in 2016 compared with 2015. Overall generation decreased 15 percent in 2016 compared with 2015 due to a change in resource mix resulting from increased purchase requirements from cogeneration and small power production (CSPP) projects, resource constraints at various generating locations, including the Langley Gulch natural gas-fired generation plant and the Jim Bridger coal-fired generating plant, due to scheduled maintenance and other factors, and more open market purchases for economic reasons. The volume decreases were partially offset by higher coal prices due to higher mining costs at BCC. The higher mining costs resulted in part due to issues with underground mining equipment that is no longer in service.

***Power Cost Adjustment Mechanisms*:** Idaho Power's power supply costs (primarily purchased power and fuel expense, 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, 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 power cost adjustment mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from customers, 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 Idaho Power (5 percent), with the exception of PURPA power purchases and demand response program incentives, which are allocated 100 percent to customers. The Idaho deferral period, or PCA year, runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period. Because of the power cost adjustment 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 below presents the components of the Idaho and Oregon power cost adjustment mechanisms for the last three years (in thousands).

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Idaho power supply cost accrual (deferral) | $ 14,658 | $ (43,841) | $ (35,802) |
| Amortization of prior year authorized balances | 37,366 | 38,511 | 52,568 |
| Total power cost adjustment expense | $ 52,024 | $ (5,330) | $ 16,766 |

The power supply accruals (deferrals) represent the portion of the power supply cost fluctuations accrued (deferred) under the power cost adjustment mechanisms. When actual power supply costs are lower than the amount forecasted in power cost adjustment rates, which was the case in 2017, most of the difference is accrued. When actual power supply costs are higher than the amount forecasted in power cost adjustment rates, which was the case for 2016 and 2015, 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 power cost adjustment year that were deferred or accrued in the prior power cost adjustment year (the true-up component of the power cost adjustment mechanism).

Power Cost Adjustment Mechanisms - 2017 Compared with 2016: Actual net power supply costs decreased in 2017 relative to 2016, resulting in a change of $58.5 million—from deferrals of $43.8 million to accruals of $14.7 million. The change from deferrals in 2016 to accruals in 2017 is due in part to the lower fuel costs and purchased power, as explained above, combined with more surplus sales than forecasted. The $37.4 million of amortization of prior year authorized balances offsets the collection from customers of prior years' deferrals.

Power Cost Adjustment Mechanisms - 2016 Compared with 2015: Actual net power supply cost deferrals increased in 2016 relative to 2015, a change of $8.0 million—from $35.8 million to $43.8 million. The increase in the deferral is due in part to higher fuel costs related to coal and purchased power and lower surplus sales than forecasted. The $38.5 million of amortization offsets the collection from customers of 2015 deferrals and was lower in 2016 as Idaho Power amortized a smaller deferral balance in 2016 than in 2015.

***Other Operations and Maintenance Expenses*:** The changes in other O&M expenses for the periods presented are discussed below.

O&M - 2017 Compared with 2016: Other O&M expense decreased by $2.2 million in 2017 compared with 2016, primarily due to a $2.4 million decrease related to previously expensed energy efficiency rider-funded costs deemed to be prudently incurred as further discussed in "Regulatory Matters" of this MD&A, and a $2.7 million decrease in thermal O&M expenses due to lower generation at thermal plants. These decreases in O&M were partially offset by a $2.5 million increase in O&M related to a settlement stipulation in Idaho, which established the reasonableness of the HCC relicensing costs incurred through December 2015 as further discussed in "Regulatory Matters" in this MD&A.

O&M - 2016 Compared with 2015: Other O&M expense increased by $9.7 million, or 3 percent, in 2016 compared with 2015 primarily due to a $6.5 million increase in labor-related expenses in 2016 due to normal increases in labor and benefits costs and higher variable employee costs, a $1.6 million increase due to scheduled maintenance at the Langley Gulch natural gas-fired generation plant, and a $1.1 million increase primarily related to transmission agreements entered into in October 2015, which also resulted in a corresponding increase in other revenue.

**Income Taxes**

IDACORP's and Idaho Power's 2017 income tax expense increased $12.2 million and $14.1 million, respectively, when compared with 2016. The increase was primarily due to higher pre-tax earnings at Idaho Power in 2017, and the $5.6 million flow-through benefit of tax deductible make-whole premiums that Idaho Power paid in connection with the early redemption of long-term debt in 2016. There were no early redemptions of long-term debt in 2017. These increases in income tax expense were partially offset by greater net flow-through income tax items at Idaho Power.

IDACORP's and Idaho Power's 2016 income tax expense decreased $9.3 million and $11.0 million, respectively, when compared with 2015. The decrease was primarily due to greater net flow-through income tax benefits at Idaho Power, a tax benefit from the adoption of a new accounting standard for share-based compensation, distributions related to fully-amortized affordable housing investments at IDACORP, and lower Idaho Power pre-tax earnings in 2016.

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reforms the Internal Revenue Code of 1986, as amended. Effective January 1, 2018, the Tax Cuts and Jobs Act permanently lowers the corporate tax rate to 21 percent from the existing maximum rate of 35 percent, provides for expanded bonus depreciation, limits the deductibility of interest expense, eliminates alternative minimum tax, repeals the manufacturing deduction, and imposes additional limitations on the deductibility of executive compensation. Public utility companies, such as Idaho Power, retain the full deductibility of interest expense and are excluded from the bonus depreciation provisions; however, traditional accelerated tax depreciation methods are still available.

As a result of the reduction of the corporate tax rate to 21 percent, generally accepted accounting principles require companies to remeasure their deferred tax assets and liabilities as of the date of enactment, with resulting tax effects accounted for in the reporting period of enactment. This remeasurement resulted in a $1.7 million and $2.0 million increase in income tax expense at IDACORP and Idaho Power, respectively, and an approximate $672 million reduction to net deferred tax liabilities of both companies. For additional information relating to IDACORP's and Idaho Power's income taxes, the effects of the Tax Cuts and Jobs Act, and 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 continues to pursue 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 $277 million in 2017, $287 million in 2016, and $284 million in 2015. Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of approximately $1.5 billion expected over the period from 2018 through 2022.

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. As of February 16, 2018, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $100 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement filed with the SEC on May 20, 2016, which may be used for the issuance of debt securities and common stock;
- Idaho Power's shelf registration statement filed with the SEC on May 20, 2016, which may be used for the issuance of first mortgage bonds and debt securities; $500 million is available for issuance 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.

Based on planned capital expenditures and operating and maintenance expenses for 2018, the companies believe they will be able to meet capital requirements and fund corporate expenses during 2018 with a combination of existing cash and operating cash flows generated by Idaho Power's utility business, together with proceeds from either draws on credit facilities or Idaho Power's issuance of debt securities. IDACORP and Idaho Power believe they could meet any short-term cash shortfall with existing credit facilities and expect to continue to manage short-term liquidity through commercial paper markets.

IDACORP and Idaho Power monitor capital markets with a view toward opportunistic debt and equity transactions, taking into account current and potential future long-term needs. As a result, IDACORP may issue debt securities or common stock, 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. To that end, on March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, Series J, maturing on March 1, 2046. On April 11, 2016, Idaho Power redeemed, prior to maturity, its $100 million in principal amount of 6.15% first mortgage bonds, Series H, due April 2019. In accordance with the redemption provisions of the original terms of the notes, the redemption included payment by Idaho Power of a make-whole premium of $14 million. The make-whole premium resulted in a current income tax deduction, which under Idaho Power's regulatory flow-through tax accounting produced an income tax benefit of approximately $5.6 million recorded in the second quarter of 2016. Idaho Power also expects to receive an incremental net benefit to net income as a result of the lower interest rate of the notes issued in March 2016 compared with the interest rate associated with the redeemed notes. Idaho Power used a portion of the net proceeds of the March 2016 sale of first mortgage bonds, medium-term notes to effect the redemption.

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, 2017, IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

| | **IDACORP** | **Idaho Power** |
|---|---|---|
| Debt | 44% | 46% |
| Equity | 56% | 54% |

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, income taxes, 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 2017 were $438 million and $420 million, respectively, an increase of $90 million for IDACORP and a $109 million increase for Idaho Power when compared with 2016. Significant items that affected the companies' operating cash flows in 2017 relative to 2016 were as follows:

- a $15 million increase and $17 million increase in IDACORP and Idaho Power net income, respectively, which includes a $19 million increase in non-cash depreciation and amortization at both companies;
- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho rate mechanisms, increased operating cash inflows by $63 million. The increase is mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho power cost adjustment and FCA mechanisms, partially offset by revenues accrued in excess of collections from the Valmy Plant settlement stipulation that will be collected in future periods;
- changes in deferred taxes and in taxes accrued and receivable combined to increase cash flows by $1 million and decrease cash flows by $23 million at IDACORP and Idaho Power, respectively;
- changes in working capital balances due primarily to timing, including fluctuations in accounts receivable, other current assets, accounts payable, and other current liabilities, as follows:
    - timing of collections of accounts receivable balances increased operating cash flows by $7 million for IDACORP and decreased operating cash flows by $6 million for Idaho Power. IDACORP collected a $8 million receivable in the first quarter of 2017 from a legal settlement;
    - the changes in other current assets increased cash flows by $14 million, which was primarily due to fluctuations in the balance in accrued unbilled revenues as energy sales near the end of the respective periods were impacted by weather; and
    - timing of accounts payable payments decreased operating cash flows by $31 million for IDACORP and increased operating cash flows by $25 million for Idaho Power (the difference relates to a $55 million payable from Idaho Power to IDACORP relating to estimated income tax payments).

IDACORP's and Idaho Power's operating cash inflows in 2016 were $348 million and $311 million, respectively, a decrease of $5 million for IDACORP and $35 million decrease for Idaho Power when compared with 2015. Significant items that affected the companies' operating cash flows in 2016 relative to 2015 were as follows:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho rate mechanisms, decreased operating cash inflows by $19 million;
- changes in deferred taxes and in taxes accrued and receivable combined to decrease cash flows by $3 million and $34 million at IDACORP and Idaho Power, respectively;
- Idaho Power received $24 million of distributions from IERCo's investment in BCC for 2016, compared with $11 million in 2015. Changes in distributions from year to year are primarily driven by changes in the timing of cash needs associated with BCC; and
- comparative changes in working capital and other assets and liabilities increased cash flows by $7 million in 2016 compared with 2015, primarily related to changes in accounts payable due to timing of payments.

**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 the allowance for borrowed funds used during construction, were $285 million, $297 million, and $294 million in 2017, 2016, and 2015, 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. As discussed in "Capital Requirements" below, Idaho Power received $6 million and $8 million in 2017 and 2016 from Boardman-to-Hemingway project joint permitting participants relating to a portion of these construction expenditures.

Idaho Power has a Rabbi trust designated to provide funding for obligations of its nonqualified defined benefit plans. In the Rabbi trust, Idaho Power purchased $11 million, $15 million, and $14 million of available-for-sale securities in 2017, 2016, and 2015, respectively. In 2017, 2016, and 2015, Idaho Power received $5 million, $16 million and $34 million, respectively, of proceeds from the sales of available-for-sale securities. Idaho Power did not use any of these proceeds to acquire company-owned life insurance in 2017, but used $10 million and $30 million of the proceeds to acquire company-owned life insurance in 2016 and 2015, respectively.

**Financing Cash Flows**

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, 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 2017, 2016, and 2015:

- on March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds Series J, maturing March 1, 2046;
- on April 11, 2016, Idaho Power redeemed, prior to maturity, $100 million of its 6.15% first mortgage bonds, Series H, due April 1, 2019, and paid a related make-whole premium of $14 million;
- on March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, Series J, maturing on March 1, 2045;
- on April 23, 2015, Idaho Power redeemed, prior to maturity, $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes due July 2018, and paid a related make-whole premium of $18 million;
- IDACORP and Idaho Power paid dividends of approximately $113 million, $105 million, and $97 million in 2017, 2016, and 2015, respectively;
- IDACORP's net change in commercial paper borrowings used cash of $22 million in 2017 and provided cash of $2 million and used cash of $11 million in 2016 and 2015, respectively; and
- Idaho Power borrowed $22 million in commercial paper in December 2016, which was paid off in January of 2017.

**Financing Programs and Available Liquidity**

***IDACORP Equity Programs:*** In recent years IDACORP has entered into sales agency agreements under which IDACORP could offer and sell shares of its common stock from time to time through BNY Mellon Capital Markets, LLC as IDACORP's agent. The most recent agency agreement terminated in May 2016, but IDACORP may choose to enter into a new sales agency agreement in the future. On May 20, 2016, IDACORP filed a shelf registration statement with the SEC, which became effective upon filing, for the potential offer and sale of an unspecified amount of shares of common stock. As of the date of this report, IDACORP is assessing whether to execute a new sales agency agreement for the issuance and sale of common stock, as the company does not anticipate issuing any shares of its common stock outside of its equity or deferral compensation programs in 2018.

Since 2012, IDACORP has not used original issue shares of common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan or the Idaho Power Company Employee Savings Plan, but instead plan administrators have used market purchases of IDACORP common stock. However, IDACORP may determine at any time to use 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.

***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 and May 2016, 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 effective through May 31, 2019, 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 requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum interest rate limit of seven percent.

On September 27, 2016, Idaho Power entered into a selling agency agreement with seven 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, secured medium term notes, Series K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture (Forty-eighth Supplemental Indenture). The Forty-eighth Supplemental Indenture provides for, among other items, (a) the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture and (b) the increase of the maximum amount of obligations to be secured by the Indenture to $2.5 billion (which maximum amount may be further increased or decreased by Idaho Power without the consent of the holders of first mortgage bonds). As of the date of this report, Idaho Power had not sold any first mortgage bonds, including Series K Notes, 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 amount of first mortgage bonds at any one time outstanding to $2.5 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2017, was limited to approximately $759 million. Idaho Power may increase the $2.5 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, 2017, Idaho Power could issue approximately $1.8 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*****:** In November 2015, IDACORP and Idaho Power entered into credit agreements for $100 million and $300 million credit facilities, respectively. These facilities replaced IDACORP's and Idaho Power's existing Second Amended and Restated Credit Agreements, dated October 26, 2011, as amended. 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 $100 million at any one time outstanding, including swingline loans not to exceed $10 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 and letters of credit not to exceed $100 million at any 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, provided that the federal funds rate and LIBOR rate will not be less than zero percent. 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, 2017, the leverage ratios for IDACORP and Idaho Power were 44 percent and 46 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. 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, 2017, 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 2018.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

While the credit facilities provide for an original maturity date of November 6, 2020, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On November 7, 2016, IDACORP and Idaho Power executed the first extension agreement and on November 7, 2017, executed the second extension agreement with the consent of all the lenders, extending the maturity date under both credit agreements to November 4, 2022. No other terms of the credit facilities, including the amount of permitted borrowing under the credit agreements, were affected by the extensions.

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. Idaho Power has obtained approval of the state public utility commissions of Idaho, Oregon, and Wyoming for the issuance of short-term borrowings through November 2022.

***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, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | IDACORP[2] | Idaho Power | IDACORP[2] | Idaho Power |
| Revolving credit facility | $ 100,000 | $ 300,000 | $ 100,000 | $ 300,000 |
| Commercial paper outstanding | — | — | — | (21,800) |
| Identified for other use[1] | — | (24,245) | — | (24,245) |
| Net balance available | $ 100,000 | $ 275,755 | $ 100,000 | $ 253,955 |

[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.

The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2017 and 2016:

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | IDACORP[1] | Idaho Power | IDACORP[1] | Idaho Power |
| **Commercial paper:** | | | | |
| Year end: | | | | |
| Amount outstanding | $ — | $ — | $ — | $ 21,800 |
| Weighted average interest rate | —% | —% | —% | 1.13% |
| Daily average amount outstanding during the year | $ 588 | $ 839 | $ 15,692 | $ 438 |
| Weighted average interest rate during the year | 1.42% | 1.12% | 0.82% | 1.13% |
| Maximum month-end balance | $ 2,425 | $ — | $ 23,900 | $ 21,800 |

[1] Holding company only.

At February 16, 2018, IDACORP had no loans outstanding under its credit facility and no commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding.

### 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 Moody’s Investors Service and Standard & Poor’s Ratings Services as of the date of this report:

| | IDACORP | Idaho Power |
|---|---|---|
| **Moody's Investors Service:** | | |
| Rating Outlook | Stable | Stable |
| Long-Term Issuer Rating | Baa1 | A3 |
| First Mortgage Bonds | None | A1 |
| Senior Secured Debt | None | A1 |
| Commercial Paper | P-2 | P-2 |
| **Standard & Poor's Rating Services:** | | |
| Corporate Credit Rating | BBB | BBB |
| Rating Outlook | Stable | Stable |
| Short-Term Rating | A-2 | A-2 |

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, 2017, Idaho Power had posted $0.9 million 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, 2017, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $5.0 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 $277 million during the year ended December 31, 2017. The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2018 through 2022 (in millions of dollars). However, 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.

| | 2018 | 2019 | 2020-2022 |
|---|---|---|---|
| Expected capital expenditures (excluding AFUDC) | $ 280-290 | $ 285-300 | $ 850-900 |

***Infrastructure Projects:*** A significant portion of expected capital expenditures included in the five-year forecast above relate to a large number of small projects as Idaho Power continues to add to its system to accommodate growth and improve reliability and operational effectiveness. These projects involve significant capital expenditures. Examples of anticipated system enhancements planned for 2018 through 2022 and estimated costs include the following:

- $35-$65 million per year for transmission system projects other than the Boardman-to-Hemingway and Gateway West projects;
- $85-$105 million per year for construction and replacement of distribution lines and stations, including replacement of underground distribution cables;
- $20-$40 million per year for ongoing improvements and replacements at coal- and natural gas-fired plants;
- $40-$65 million per year for hydroelectric plant improvement programs, including relicensing costs; and
- $45-$75 million per year for general plant improvements, such as land and buildings, vehicles, information technology, and communication equipment.

***Other Major Infrastructure Projects:*** Idaho Power has recently completed or is engaged in the development of a number of significant projects and has entered into arrangements with third parties for joint development of infrastructure projects. The most notable projects are described below.

<u>Jim Bridger Plant Selective Catalytic Reduction Equipment</u>: Idaho Power and the plant co-owners recently completed installation of 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 provided for installation of SCR on unit 3 and unit 4. The rules provide for an equivalent technology for $NO_x$ reductions on unit 2 by 2021 and unit 1 by 2022.The unit 3 SCR was operating as of November 2015, and the unit 4 SCR was operating as of November 2016. In light of the substantial estimated cost of the SCR installation, as of the date of this report, Idaho Power is assessing whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant. The expected capital expenditures in the table above do not include any estimated expenditures relating to the installation of SCR on units 1 and 2.

<u>Boardman-to-Hemingway Transmission Line</u>: 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. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration 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. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including Idaho Power's AFUDC. This

cost estimate is preliminary and 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 in addition to approximately $50 million of Idaho Power's share of costs related to early construction efforts primarily included in the periods 2020-2022. These preliminary estimates of Idaho Power's share of early construction costs could significantly change as the construction timeline nears and as the project participants further align on future activities and estimates.

Approximately $95 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through December 31, 2017. Pursuant to the terms of the joint funding arrangements, Idaho Power has received $68 million, including $19 million received in January 2018, due from project partners for their share of those costs. As of the date of this report, no material partner reimbursements are outstanding. Joint permitting participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

The permitting phase of the Boardman-to-Hemingway project is subject to federal review and approval by the U.S. Bureau of Land Management (BLM), the U.S. Forest Service, the Department of the Navy, and certain other federal agencies. The BLM issued its record of decision for the project in November 2017. The U.S. Forest Service and Department of Navy are expected to issue their respective decisions in 2018.

In the separate Oregon state permitting process, in June 2017, Idaho Power submitted its amended preliminary application for site certificate and expects the Oregon Department of Energy to issue a draft proposed order on the application in 2018. Given the status of ongoing permitting activities and construction period, Idaho Power expects the in-service date for the line would be in 2025 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 joint funding agreement for permitting of the project. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $60 million, including AFUDC. Idaho Power has expended approximately $35 million on the permitting phase of the project through December 31, 2017. 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. Idaho Power's share of potential early construction costs are excluded from the capital requirements table above because the timing of construction of Idaho Power's portion of the project is uncertain.

The permitting phase of the Gateway West project is subject to review and approval of the BLM. The BLM released its record of decision in November 2013 for eight of the ten transmission line segments. In May 2017, a federal bill was signed into law that issued a right-of-way for certain portions of the remaining Gateway West segments. The other portions of the remaining segments continue to be subject to the BLM's review and approval. Idaho Power expects the BLM to issue a record of decision for the outstanding portions of the remaining segments in 2018.

Hells Canyon Complex Relicensing: 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. Idaho Power has been engaged in the process of obtaining from the FERC a new long-term license for the HCC. The past and anticipated future costs associated with obtaining a new long-term license for the HCC are significant. As of the date of this report, Idaho Power estimates that the annual costs it will incur to obtain a new long-term license for the HCC, including AFUDC but excluding costs expected to be incurred for complying with the license after issuance, are likely to range from $25 million to $35 million until issuance of the license, which Idaho Power estimates will occur no earlier than 2022. Idaho Power expects that the annual capital expenditures and operating and maintenance expenses associated with compliance with the terms and conditions of the long-term license could also be substantial, but the company is currently unable to estimate those costs in light of the uncertainty surrounding the ultimate terms and conditions that may be included in the license. Idaho Power intends to seek recovery of those relicensing and compliance costs in rates through the regulatory process. In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future rate proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third party intervenor recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. The settlement stipulation is subject to review and approval by the IPUC. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017. As of the date of this report, the IPUC has not issued an order in this matter. Refer to "Regulatory Matters" in this MD&A for additional details relating to the relicensing process.

***Environmental Regulation Costs:*** Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal-fired plants and for its hydroelectric relicensing efforts. The near-term cost estimates for environmental matters 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 does 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.

***Long-Term Resource Planning:*** The IPUC and OPUC require that Idaho Power prepare biennially an IRP. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side, demand-side, and transmission options, and identifies potential near-term and long-term actions. Idaho Power filed its most recent IRP with the IPUC and OPUC in June 2017. The 2017 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line by 2026, the end to Idaho Power's participation in coal-fired operations at the Valmy Plant units 1 and 2 in 2019 and 2025, respectively, and the early retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively, with no other new resource needs prior to 2026. However, as noted in the 2017 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third party development of renewable resources, fuel commodity prices, environmental requirements, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant operation and retirements. These uncertainties, as well as others, could result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. Additional information on Idaho Power's 2017 IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

**Defined Benefit Pension Plan Contributions and Recovery**

Idaho Power contributed $40 million in both 2017 and 2016 to its defined benefit pension plan and $39 million in 2015. Idaho Power estimates that it has no minimum contribution requirement for 2018. Depending on market conditions and cash flow considerations in 2018, Idaho Power could contribute up to $40 million to the pension plan during 2018. Idaho Power's contributions are made in a continued effort to balance the regulatory collection of these expenditures with the amount and timing of contributions to mitigate the cost of being in an underfunded position. Beyond 2018, Idaho Power expects continuing significant contribution obligations under the pension plan. Refer to Note 10 - "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, 2017, Idaho Power's deferral balance associated with the Idaho jurisdiction was $128 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. The IPUC has authorized Idaho Power to recover and amortize $17 million of deferred pension costs annually, and has applied $68 million against the deferred amount under its Idaho sharing mechanisms since 2011. The primary impact of pension contributions is on the timing of cash flows, as cost recovery lags behind the timing of contributions.

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. The majority of the law changes, including the rate reduction, became effective on January 1, 2018. Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law will benefit Idaho Power customers and affect IDACORP's and Idaho Power's financial condition and results of operations. Although not expected by Idaho Power, if the regulatory decisions of the IPUC and OPUC result in significant reductions to Idaho Power revenues in excess of any cash savings from the federal income tax law changes, it could adversely affect IDACORP's and Idaho Power's cash flows from operations and potentially require Idaho Power to increase cash from financing activities. At this time, the companies are unable to determine what impact the regulatory proceedings related to the Tax Cuts and Jobs Act will have on future IDACORP and Idaho Power liquidity. See "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings.

## Contractual Obligations

The following table presents IDACORP’s and Idaho Power’s contractual cash obligations as of December 31, 2017, for the respective periods in which they are due:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| | Total | 2018 | 2019-2020 | 2021-2022 | Thereafter |
| | (millions of dollars) | | | | |
| Long-term debt[1] | $ 1,765 | $ — | $ 230 | $ 75 | $ 1,460 |
| Future interest payments[2] | 1,383 | 82 | 160 | 144 | 997 |
| Operating leases[3][4] | 52 | 4 | 9 | 9 | 30 |
| Purchase obligations: | | | | | |
| Cogeneration and small power production | 4,124 | 234 | 460 | 479 | 2,951 |
| Fuel supply agreements | 229 | 43 | 57 | 36 | 93 |
| Other[4][5] | 235 | 49 | 45 | 37 | 104 |
| Pension and postretirement benefit plans[6] | 252 | 10 | 93 | 98 | 51 |
| Other long-term liabilities - IDACORP only[4] | 2 | — | — | — | 2 |
| Total | $ 8,042 | $ 422 | $ 1,054 | $ 878 | $ 5,688 |

(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, 2017.

(3) The operating leases include right-of-way easements.

(4) Approximately $34 million of the amounts in operating leases, $80 million of the amounts in other purchase obligations, and $2 million of the amounts in IDACORP only other long-term liabilities are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(5) Other purchase obligations also include 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 2022 with any level of precision, and amounts through 2022 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 September of 2015, 2016, and 2017, IDACORP's board of directors voted to increase the quarterly dividend to $0.51 per share, $0.55 per share, and $0.59 per share of IDACORP common stock, respectively. IDACORP's dividends during 2017 were 53 percent of actual 2017 earnings.

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. 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 $56.7 million at December 31, 2017, representing IERCo's one-third share of BCC's total reclamation obligation of $170.1 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2017, the value of the reclamation trust fund totaled $103.4 million. During 2017, the reclamation trust fund made no distributions 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 adds a per-ton surcharge to coal sales. 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 regulatory strategy takes into consideration short-term and long-term needs for rate relief and involves several factors that can affect the timing of rate filings. These factors include, among others, in-service dates of major capital investments, the timing of changes in major revenue and expense items, and customer growth rates. Idaho Power's most recent general rate cases in Idaho and Oregon were filed during 2011, and Idaho Power filed a large 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. Idaho Power also reset its base-rate power supply expenses in the Idaho jurisdiction for purposes of updating the collection of costs through retail rates in 2014 but without a resulting net increase in rates. Between general rate cases, Idaho Power relies upon customer growth, power cost adjustment mechanisms, tariff riders, and other mechanisms to reduce the impact of 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 regulatory focus in recent years has been largely on regulatory settlement stipulations and the design of rate mechanisms. Idaho Power continues to assess the need and timing of filing a general rate case in its two retail jurisdictions, based on its consideration of the factors described above, but does not anticipate filing a general rate case in 2018.

### Notable Retail Rate Changes in Idaho and Oregon

Included in the table that follows are notable regulatory developments during 2017, 2016, and 2015 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 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 Rate Impact (millions)[1] |
|---|---|---|
| Oregon Valmy Plant Settlement Stipulation | 7/1/2017 | $ 1 |
| Idaho Valmy Plant Settlement Stipulation | 6/1/2017 | 13 |
| 2017 Idaho PCA[2] | 6/1/2017 | 11 |
| 2017 Idaho FCA | 6/1/2017 | 7 |
| 2016 Idaho PCA[3] | 6/1/2016 | 17 |
| 2016 Idaho FCA | 6/1/2016 | 11 |
| 2015 Idaho PCA[4] | 6/1/2015 | (12) |
| 2015 Idaho FCA | 6/1/2015 | 2 |

(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. The rate changes for the Idaho PCA and FCA are applicable only for one-year periods.

(2) 2017 Idaho PCA rates reflect the application of $13.0 million of surplus Idaho energy efficiency rider funds.

(3) 2016 Idaho PCA rates reflect the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of an October 2014 settlement stipulation and (b) $4.0 million of surplus Idaho energy efficiency rider funds.

(4) 2015 Idaho PCA rates reflect the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of a December 2011 settlement stipulation, (b) a $1.5 million customer benefit relating to a change to the PCA methodology described below, and (c) $4.0 million of surplus Idaho energy efficiency rider funds.

### Idaho and Oregon General Rate Cases and Base Rate Adjustments

Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from the regulatory settlement of a general rate case filing Idaho Power made in 2011. In the general rate case, the IPUC issued an order approving a settlement stipulation that provided for an overall 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a $34.0 million overall increase in Idaho Power's annual Idaho-jurisdictional base rate revenues. Neither the IPUC's order nor the settlement stipulation specified an authorized rate of return on equity.

Effective March 1, 2012, Idaho Power implemented new Oregon base rates resulting from its receipt of an order from the OPUC approving a settlement stipulation in its general rate case proceedings that provided for a $1.8 million base rate revenue increase, a rate of return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction.

Idaho and Oregon base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. In June 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rate revenues, effective July 1, 2012, for inclusion of the investment and associated costs of the plant in rates. The order also provided for a $335.9 million increase in Idaho rate base. On September 20, 2012, the OPUC issued an order approving a $3.0 million increase in annual Oregon jurisdiction base rate revenues, effective October 1, 2012, for inclusion of the investment and associated costs of the plant in Oregon rates.

In March 2014, the IPUC issued an order approving Idaho Power's application 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 became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the PCA mechanism and instead results in collecting that portion through base rates.

### Valmy Base Rate Adjustment Settlement Stipulations and Depreciation Rate Settlement Stipulations

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for the Valmy Plant. The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017 in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted.

In May 2017, the IPUC and OPUC approved settlement stipulations related to revised depreciation rates for Idaho Power's other electric plant in service, and adjusted base rates in Oregon to reflect the revised depreciation rates applied to electric plant-in-service based on balances from the most recent general rate case. These settlement stipulations provided for new depreciation rates to go into effect on June 1, 2017, with no significant resulting increase in revenue.

In 2017, the settlement stipulations increased general business revenue collections, general business revenue accruals, net depreciation expense, and income tax expense, including plant-related flow-through tax adjustments. Compared with Idaho Power’s estimate of what ongoing net income would have been without the settlement stipulations, the settlement stipulations are expected to increase after-tax net income by approximately $5 million on an annual basis. Idaho Power expects the ongoing annual benefit to net income from the Valmy Plant settlement stipulations to decline slightly each year through 2028, primarily due to the annual decline in Valmy Plant-related rate base, which is expected to be fully depreciated by December 31, 2028.

**Non-Base Rate Idaho Regulatory Settlement Stipulations**

***Settlement Stipulation for 2012 to 2014***: 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. Under the December 2011 settlement stipulation, 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.

***Settlement Stipulation for 2015 to 2019***: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 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 October 2014 settlement stipulation are described in Note 3 - "Regulatory Matters - *Notable 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.

In 2017, Idaho Power's Idaho ROE was between 9.5 and 10.0 percent, and thus Idaho Power recorded no additional ADITC amortization and no provision for sharing with customers. Accordingly, at December 31, 2017, the full $45 million of additional ADITC remains available for future use under the terms of the settlement stipulation.

Idaho Power recorded the following for sharing with customers under the December 2011 and October 2014 Idaho Settlement Stipulations (in millions):

| Year | Recorded as Refunds to Customers | Recorded as a Pre-tax Charge to Pension Expense | Total |
|---|---|---|---|
| 2017 | $ — | $ — | $ — |
| 2016 | — | — | — |
| 2015 | 3.2 | — | 3.2 |
| 2014 | 8.0 | 16.7 | 24.7 |
| 2013 | 7.6 | 16.5 | 24.1 |
| 2012 | 7.2 | 14.6 | 21.8 |
| Total | $ 26.0 | $ 47.8 | $ 73.8 |

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. On January 17, 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to 1) record a deferred regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in federal income tax law and 2) to file a report with the IPUC by March 30, 2018, identifying and quantifying the income tax changes along with proposed tariff schedule changes. The IPUC order requires Idaho Power to estimate the income tax changes by comparing actual 2017 federal income tax expense components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full year of 2017. Idaho Power is currently working to comply with the IPUC order.

On December 29, 2017, Idaho Power filed an application with the OPUC requesting authority to defer for later ratemaking treatment the Oregon jurisdictional earnings in excess of the currently authorized Oregon jurisdictional rate of return on equity that may result from the Tax Cuts and Jobs Act. On December 29, 2017, OPUC Staff also filed an application with the OPUC requesting authority to defer for later ratemaking treatment the difference between Idaho Power’s current retail rates and its current retail rates inclusive of the impact of the Tax Cuts and Jobs Act.

Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law may benefit Idaho Power customers and affect IDACORP's and Idaho Power's financial condition and results of operations. The method through which potential cost savings may be accrued for the benefit of customers, including potential reductions to customer rates and to regulatory deferrals, will require approval from the IPUC and OPUC.

**Idaho Energy Efficiency Rider**

On an annual basis, Idaho Power applies to the IPUC for an order designating Idaho Power’s prior calendar year Idaho Energy Efficiency Rider (Idaho Rider) funded expenses as prudently incurred. In October 2017, the IPUC issued its order determining that the 2011 - 2016 incremental Idaho Rider funded labor expenses of $1.9 million were prudently incurred. In its order, the IPUC also authorized actual Idaho Rider funded wage increases after 2016. The prudence order resulted in a $2.4 million increase in operating income in 2017. For more information on the order and its impacts on results, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

**Customer-Owned Generation Filing**

On July 27, 2017, Idaho Power filed an application with the IPUC requesting the creation of two new classes for residential and small general service customers who choose to install customer-owned generation on or after January 1, 2018. If approved as proposed, Idaho Power does not, as of the date of this report, anticipate that the creation of these new rate classes would impact in the near term the current rates for the approximately 1,700 residential and small general service customers and applicants who currently take or are requesting net metering services from Idaho Power for their customer-owned generation.

**Deferred 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 power cost adjustment mechanisms in its Idaho and Oregon jurisdictions provide for annual adjustments to the rates charged to retail customers. The power cost adjustment mechanisms 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 power cost adjustment 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, these factors can vary significantly, which can result in significant accruals and deferrals under the power cost adjustment mechanisms. The power cost adjustment rate changes reflected in the table under the heading "Notable Retail Rate Changes in Idaho and Oregon" are illustrative of the volatility of net power supply costs and the impact on power cost adjustment rates.

The following table summarizes the change in deferred net power supply costs over the prior two years (in thousands):

| | Idaho | Oregon[1] | Total |
|---|---|---|---|
| Balance at December 31, 2015 | $ 44,556 | $ 2,664 | $ 47,220 |
| Current period net power supply costs deferred | 43,841 | — | 43,841 |
| Revenue sharing | (3,171) | — | (3,171) |
| Energy efficiency rider funds transferred to Idaho PCA mechanism | (3,970) | — | (3,970) |
| Prior amounts recovered through rates | (27,316) | (2,502) | (29,818) |
| Sulfur Dioxide ($SO_2$) allowance and renewable energy certificate (REC) sales | (874) | (41) | (915) |
| Interest and other | 376 | 307 | 683 |
| Balance at December 31, 2016 | 53,442 | 428 | 53,870 |
| Current period net power supply costs accrual | (14,658) | — | (14,658) |
| Energy efficiency rider funds transferred to Idaho PCA mechanism | (13,000) | — | (13,000) |
| Prior amounts recovered through rates | (26,121) | (508) | (26,629) |
| $SO_2$ allowance and renewable energy certificate (REC) sales | (2,104) | (65) | (2,169) |
| Interest and other | 240 | 40 | 280 |
| Balance at December 31, 2017 | $ (2,201) | $ (105) | $ (2,306) |

(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.

**Recovery of Costs for Anticipated Participation in Western Energy Imbalance Market**

In January 2017, the IPUC issued an order authorizing Idaho Power’s requested deferral accounting treatment for costs associated with joining the Western EIM. Idaho Power can defer costs incurred until the earlier of when Idaho Power begins recovery of the costs and the deferral balance or the end of 2018. Idaho Power anticipates that it will begin participating in the Western EIM in April of 2018. The Western EIM is intended to reduce the power supply 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.

In November 2017, Idaho Power filed an application with the IPUC requesting approval to establish an interim method of recovery for costs associated with participation in the Western EIM. If the IPUC approves the application as filed, Idaho Power intends to include $3.6 million in costs for recovery through the PCA, beginning June 1, 2018. Idaho Power has requested a decision from the IPUC by March 31, 2018.

### Open Access Transmission Tariff Rate Proceedings

Idaho Power uses 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. In August 2017, Idaho Power filed its 2017 final transmission rate with the FERC, reflecting a transmission rate of $34.90 per kW-year, to be effective for the period from October 1, 2017 to September 30, 2018. Idaho Power's final rate was based on a net annual transmission revenue requirement of $130.4 million. The OATT rate in effect from October 1, 2016 to September 30, 2017, was $25.52 per kW-year based on a net annual transmission revenue requirement of $127.4 million. The increase in the OATT rate was largely attributable to an asset exchange transaction with one transmission customer, and the termination of legacy long-term transmission service agreements and its impact on the transmission formula rate, which was fully incorporated in the new formula rate, effective October 1, 2017. For more information on the new formula rate, refer to *Transmission Revenues Associated with Asset Exchange Transaction* below in this "Regulatory Matters" section in this MD&A.

Historic OATT rate information is included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

### Transmission Revenues Associated with Asset Exchange Transaction

Effective in October 2015, Idaho Power and PacifiCorp each transferred to the other certain interests in transmission-related equipment. In connection with that transaction, the companies terminated or amended a number of long-term agreements between Idaho Power and PacifiCorp related to the ownership and operation of transmission-related equipment and transmission services. In 2014, Idaho Power collected approximately $8 million in transmission revenues under long-term transmission agreements that were terminated in connection with the asset exchange transaction. As a result of the transaction and termination of those long-term transmission agreements, Idaho Power's OATT rate increased; however, in accordance with FERC's current formula rate methodology the increase phased in over two annual rate proceedings. The impact of the asset exchange on the transmission formula rate was fully incorporated in the new formula rate, effective October 1, 2017.

In compliance with the IPUC's order approving the asset exchange transaction, Idaho Power submitted to the IPUC a request for verification that its regulatory accounting method reflecting a symmetrical tracking of changes in transmission revenues resulting specifically from the asset exchange with PacifiCorp complies with the IPUC’s order. As an alternative proposed by Idaho Power to its symmetrical tracking, in August 2016, the IPUC ordered that any changes in transmission revenues resulting from the asset exchange will be addressed, prospectively, in Idaho Power's next general rate case.

### Relicensing of Hydroelectric Projects

***Overview:*** Idaho Power, like other utilities that operate non-federal 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 a new multi-year license is issued by the FERC, at which time the charges are transferred to electric plant in service. Idaho Power expects to seek recovery of relicensing costs and costs related to a new long-term license through the regulatory process and, in December 2016, submitted a request for a determination of prudence of HCC relicensing costs, which is described below. Relicensing costs of $268.7 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, 2017. 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 when grossed-up for the effect of 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, 2017, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $120 million. In addition to the discussion below, refer to "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 environmental impact statement (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 the 2016 Section 401 certification application process, Oregon required Idaho Power to comply with fish passage and reintroduction conditions. Idaho's water quality certification, however, provides that Idaho Power shall take no action that may result in the reintroduction or establishment of spawning populations of any fish species into Idaho's waters without consultation with and express approval of the State of Idaho. On November 30, 2016, Idaho Power filed a petition with the FERC requesting that the FERC resolve the conflict between Oregon's and Idaho's conditions and declare that the FPA pre-empts the Oregon state law. In January 2017, the FERC issued an order denying Idaho Power’s petition, stating that the petition for a declaratory order was premature, cannot realistically be considered separately from the issue of the states’ certification authority under the CWA Section 401, and raises issues that are beyond the FERC’s authority to decide. In February 2017, Idaho Power sought rehearing before the FERC on the January 2017 order, which the FERC denied. On February 16, 2018, Idaho Power filed an appeal of the FERC's January 2017 order with the D.C. Circuit Court.

In April 2017, the governors of Oregon and Idaho jointly requested that Idaho Power withdraw and resubmit its Section 401 certification applications in both states to allow the states additional time to negotiate a potential resolution of the disputed issues. As of November 2017, the states were not able to resolve their differences timely enough within the one-year cycle, requiring Idaho Power to again withdraw and resubmit its Section 401 certification applications in both states. Idaho Power withdrew and refiled a 401 certification application on November 22, 2017. Idaho Power continues to work with the states towards a mutually agreeable solution.

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. 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 construction of new aerated runners at the Brownlee project (part of the HCC) at an estimated cost of $57 million. Two of four units were installed by the end of 2017 and Idaho Power plans to install the third and fourth units in 2018 and 2019, respectively. Other measures that have been proposed or considered have included modification of spillways at two dams in the HCC 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 Section 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. However, as of the date of this report, Idaho Power estimates that the annual costs it will incur to obtain a new long-term license for the HCC, including AFUDC but excluding costs expected to be incurred for complying with the license after issuance, are likely to range from $25 million to $35 million until issuance of the license, which Idaho Power estimates will occur no earlier than 2022. In light of the costs incurred and the considerable passage of time, in December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future rate proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC Staff, and a third party intervenor recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. The settlement stipulation is subject to review and approval by the IPUC. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017. As of the date of this report, the IPUC has not issued an order in this matter.

**2017 Integrated Resource Plan**

The IPUC and OPUC require that Idaho Power prepare biennially an IRP. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side, demand-side, and transmission options, and identifies potential near-term and long-term actions. Idaho Power filed its most recent IRP with the IPUC and OPUC in June 2017. In October 2017, OPUC Staff and third party intervenors filed comments to the 2017 IRP with the OPUC, requesting additional information related to the need for the Boardman-to-Hemingway transmission line and Idaho Power's forecasts, among other items. Idaho Power filed its response to the comments and supplemental information for the 2017 IRP in December 2017. On February 9, 2018, the IPUC issued an order acknowledging the 2017 IRP. As of the date of this report, the OPUC has not issued an order acknowledging the 2017 IRP.

**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 five- or ten-percent RPS in Oregon beginning in 2025 (depending on loads at that time), and Idaho Power expects to meet either RPS requirement with Renewable Energy Certificates (REC) obtained from the purchase of power from the Elkhorn Valley wind project.

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95 percent with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2017, 2016, and 2015, Idaho Power's REC sales totaled $2.3 million, $1.0 million, and $1.8 million, respectively.

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 2012 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 power cost adjustment mechanisms.

***Renewable and Other Energy Contracts:*** Idaho Power has contracts for the purchase of electricity produced by third-party generation facilities, most of which produce energy with the use of renewable generation sources such as wind, solar, biomass, small hydroelectric and geothermal. The majority of these contracts are entered into as mandatory purchases under PURPA. As of December 31, 2017, Idaho Power had contracts to purchase energy from 127 on-line PURPA projects. An additional three contracts are with non-PURPA projects, including the Elkhorn Valley wind project with a 101-MW nameplate capacity. The following table sets forth, as of December 31, 2017, the resource type and nameplate capacity of Idaho Power's signed agreements for power purchases from PURPA and non-PURPA generating facilities. These agreements have original contract terms ranging from one to 35 years.

| Resource Type | Total On-line (MW) | Under Contract but not yet On-line (MW) | Total Projects under Contract (MW) | Began Operating During 2017 (MW) |
|---|---|---|---|---|
| **PURPA:** | | | | |
| Wind | 627 | — | 627 | 50 |
| Solar | 290 | 24 | 314 | 120 |
| Hydroelectric | 147 | — | 147 | — |
| Other | 50 | 5 | 55 | — |
| Total PURPA | 1,114 | 29 | 1,143 | 170 |
| **Non-PURPA:** | | | | |
| Wind | 101 | — | 101 | — |
| Geothermal | 35 | — | 35 | — |
| Total non-PURPA | 136 | — | 136 | — |

Of the five projects not yet on-line, one biomass project is expected to be on-line in 2018 and four solar projects are scheduled to be on-line in 2019.

## ENVIRONMENTAL MATTERS

### Overview

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 environment, including the CAA, the CWA, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the ESA, among other laws. 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 fossil fuel-fired generation plants and constructing new generation and transmission facilities, in large part through the substantial cost of permitting activities and the required installation of additional pollution control devices. In many parts of the United States, some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate. The decision to agree to cease operation of the Boardman coal-fired plant, in which Idaho Power owns a 10 percent interest, by the end of 2020, was based in part on the significant future cost of compliance with environmental laws and regulations. The decision to pursue an end to participation in coal-fired operations at the Valmy Plant was also based primarily on the economics of operating the plant. Additionally, in light of the uncertainty resulting from pending environmental regulation and the substantial estimated cost of selective catalytic reduction equipment (SCR) installation, Idaho Power is assessing whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant. Beyond 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 2018 to 2020.

Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2020, though they could be substantial. Furthermore, several executive orders issued in 2017 concerning environmental regulations, as described below, could result in significant changes in, and uncertainty with respect to, legislation, regulation, and government policy regarding environmental matters. Idaho Power may delay making operational changes or environmental-related expenditures while such changes are pending to avoid implementing uncertain laws, rules, and policies.

**Executive Orders on Environmental Matters**

In March 2017, an executive order was issued directing the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan (CPP), the greenhouse gas new source performance standards (GHG NSPS), and the proposed Federal Implementation Plan (FIP) for CPP and, if appropriate, to propose rules suspending, revising, or rescinding the CPP, GHG NSPS, and proposed FIP within 45 to 120 days after the date of the order. The order also directed the Secretary of the Interior to lift the moratorium on federal land for coal leasing activities and revoke certain Obama Administration directives regarding the nature and extent of mitigation required for projects on federal lands. The order also addressed other climate-related issues, including rescinding the technical support documents that estimate the social cost of carbon, rescinding the National Environmental Policy Act (NEPA) guidance on greenhouse gases, and rescinding climate-related actions undertaken by the previous presidential administration, among other issues. Shortly after the orders were issued, the EPA notified each state’s governor that if any deadlines under the CPP become relevant in the future, the EPA will toll its requirement for states to comply with the regulation. In October 2017, the EPA announced a proposal to repeal the CPP, and in December 2017, provided an advance notice of rulemaking, asking for public input in early 2018 on a rule to replace the CPP. The proposed replacement rule focuses on limiting pollution reduction measures to those measures that can be applied at the energy source. As of the date of this report and in light of these executive actions, Idaho Power is uncertain whether and to what extent the replacement CPP may impact its operations in the near term.

In August 2017, another executive order was issued to accelerate federal agencies' environmental review and permitting for major infrastructure projects. The outcome of the EPA’s and other federal agencies' review of regulations covered by the executive orders is difficult to predict. Changes to or elimination of regulations may lower Idaho Power's costs of operating and maintaining fossil fuel-fired generation plants and transmission lines, due to the reduction of potential environmental infrastructure upgrades or reduction or elimination of permitting requirements. The executive orders and resulting federal regulations could, on the other hand, be affected by Congressional action and challenged in court. Further, state and local governmental authorities could choose to replace the federal regulations or bolster environmental compliance and enforcement efforts at the local level, and therefore, Idaho Power is uncertain whether and to what extent the orders could affect its operations and environmental-related expenditures. Idaho Power plans to continue to monitor actions associated with or resulting from the executive orders.

**Endangered Species Act 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 agencies also designate “any habitat of such species which is then considered to be critical habitat.” The ESA also provides that each federal agency must 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 agency must adopt changes to the proposed action to avoid the adverse modification. These changes are often quite extensive and can affect the size, scope, and even the feasibility of a project moving forward. In February 2016, the U.S. Fish and Wildlife Service (USFWS) and the NMFS issued a set of regulatory and policy changes relating to critical habitat and adverse modification determinations under the ESA. While the ultimate impact of implementation of those changes is yet to be determined, taken as a whole, Idaho Power believes that the changes could result in the applicable agencies having greater authority in making 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, including the slickspot peppergrass. 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 operational adjustments and could adversely impact the amount of output from hydroelectric dams, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

***Developments in Regulation of Sage Grouse Habitat:*** In February 2016, a lawsuit was filed in the U.S. District Court of Idaho challenging the BLM's sage grouse resource management and land use plan revisions that became effective in 2015 under the Federal Land Policy and Management Act. The lawsuit challenges the plans and associated environmental impact statements across the sage grouse range and alleges that the plans fail to ensure that sage grouse populations and habitats will be protected and restored in accordance with the best available science and legal mandates. Further, the complaint challenges certain exemptions provided for the Boardman-to-Hemingway and Gateway West transmission line projects. Idaho Power has intervened in the proceedings in an effort to support the exemptions provided for in the BLM's plans. If the exemptions are overturned, Idaho Power may be required to re-route the projects, which could lead to substantially higher construction and permitting costs and could delay construction.

In May 2016, a separate lawsuit was filed in the U.S. District Court of North Dakota, challenging the BLM's sage grouse resource management and land use plan revisions, including the exemptions provided for the Boardman-to-Hemingway and Gateway West transmission line projects. In October 2016, the plaintiffs amended their complaint to no longer challenge the exemptions; however, in December 2016, the North Dakota court transfered claims challenging certain Idaho land use plan amendments to the U.S. District Court for the District of Columbia. Idaho Power is participating in the proceedings in an effort to protect its interests.

In June 2017, the Secretary of the Interior issued an order directing the BLM to review the 2015 sage grouse resource management and land use plan revisions and to identify provisions that may require modification or rescission to address energy and other development of public lands. In October 2017, the Secretary of the Interior issued a notice of intent declaring the Department of the Interior’s intent to consider amending the 2015 sage grouse resource management and land use plan revisions. As of the date of this report, the above lawsuits are stayed as the parties and the courts consider the Department of the Interior’s review of the sage grouse resource management and land use plan revisions.

***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 2018 is unlikely.

Boardman-to-Hemingway and Gateway West Transmission Projects: In August 2016, the USFWS re-instated the threatened species status of slickspot peppergrass. Most of the species are located on federal land. Idaho Power expects the listing of the slickspot peppergrass and its existence within or near the proposed routes for the Boardman-to-Hemingway and Gateway West transmission line projects to continue to impact the cost and timing of permitting and construction of the projects, as it requires an ESA Section 7 consultation. The USFWS has also indicated it intends to designate critical habitat for the species. If critical habitat is designated within the vicinity of the transmission line projects, Idaho Power expects that the designation could increase the cost of obtaining permits for the projects and could further delay the in-service date of the projects.

***Endangered Species Act and National Environmental Policy Act Developments:*** In May 2016, the United States District Court for the District of Oregon issued an opinion finding that in the context of hydroelectric facilities owned and operated by the U.S. Army Corps of Engineers and located on the lower Snake River, National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NOAA Fisheries) violated the ESA by using improper standards, failing to consider adequately the impact of climate change on habitat conditions, and placing undue reliance on unproven, future federal habitat conservation measures, particularly to the degree that the success of the measures could be undermined by climate change. The court also found that other federal agencies violated the National Environmental Policy Act (NEPA) by failing to prepare a comprehensive environmental impact statement on implementation of the conservation measures ordered by NOAA Fisheries, including analysis of the measures directed by NOAA Fisheries and other reasonable alternatives. The court's opinion and its emphasis on a climate change-driven analysis element, if generalized to other situations, could require ESA-driven avoidance, minimization, and compensatory mitigation efforts to incorporate surplus measures to ensure species' protection, which could result in considerable increases in cost beyond the cost of additional analysis in the NEPA process. In September 2016, federal agencies initiated an environmental impact statement process to examine hydroelectric dams on the lower Snake River, which Idaho Power expects will take place over a five-year period. None of Idaho Power's hydroelectric facilities are included in the studies.

**Climate Change and the Regulation of Greenhouse Gas 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, wildfires, drought, and other natural phenomena and natural disasters 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 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 have raised uncertainty about the future viability of fossil fuels, most notably 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. Some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate, particularly in light of continued low natural gas prices that decrease the cost to operate natural gas-fired power plants.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions. These include the specific GHG emissions limits imposed, 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 the timing and amount of 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; Clean Power Plan:*** The EPA has been 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.

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. While the rule is complex, Idaho Power believes that its owned and co-owned fossil fuel-fired generation plants are, as of the date of this report, in compliance with the GHG Tailoring Rule.

In June 2014, the EPA released, under Section 111(d) of the CAA, a proposed rule for addressing GHG from existing fossil fuel-fired electric generating units (EGUs). The proposed rule was intended to achieve a 30 percent reduction in $CO_2$ emissions from the power sector by 2030. On August 3, 2015, the EPA released the final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan (CPP), which requires states to adopt plans to collectively reduce 2005 levels of power sector $CO_2$ emissions by 32 percent by the year 2030. The final rule provides states until September 2018 to submit implementation plans, phasing in several compliance periods beginning in 2022 and achieving the final emissions goals by 2030. In October 2017, the EPA announced a proposal to repeal the CPP, and in December 2017 provided an advance notice of rulemaking, asking for public input in early 2018 on a rule to replace the CPP. The proposed replacement rule focuses on limiting pollution reduction measures to those measures that can be applied at the energy source.

Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, and due to the existing and potential changes in legislation, regulation, and government policy with respect to environmental matters as a result of the presidential administration's executive orders and the EPA's proposal to repeal and replace the CPP discussed above, as of the date of this report and in light of these executive actions, Idaho Power is uncertain whether and to what extent the replacement CPP may impact its operations in the near term.

***State GHG Initiatives and Idaho Power's Voluntary GHG Reduction Initiative:*** 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 but is scheduled to cease coal-fired operations in 2020.

In Oregon, legislation referred to as the Oregon Clean Electricity and Coal Transition Plan was enacted in March 2016, and requires certain Oregon utilities to remove coal-fired generation from their Oregon retail rates by 2030. Oregon utilities would be permitted to sell the output of coal-fired plants into the wholesale market or reallocate such plants to other states. To the extent Idaho Power is subject to the legislation, it plans to seek recovery, through the ratemaking process, of operating and capitalized costs related to its coal-fired generation assets and removal of any of those assets from Oregon rate base.

The State of Idaho has not passed legislation specifically regulating GHGs. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but they 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 is engaged in voluntary GHG emissions intensity reduction efforts, which is discussed in Part I, Item 1 - "Business - Utility Operations - *Environmental Regulation and Costs*."

**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 apply to Idaho Power. These include the final Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards (NAAQS), New Source Review / Prevention of Significant Deterioration (NSR/PSD) Rules, and the Regional Haze Rule.

***MATS Implementation:*** The final MATS rule under the CAA, previously referred to as the Utility MACT Rule, was issued in February 2012. The final rule established emission limits for hazardous air pollutants from new and existing coal-fired and oil-fired steam electric generating units. The MATS rule provided that sources must be in compliance with emission limits by April 2015. Idaho Power and the plant co-owners have installed mercury continuous emission monitoring systems on all of the coal-fired units at the Jim Bridger, Boardman, and North Valmy coal-fired generating plants, along with control technology to reduce mercury, acid gases, and particulate matter emissions for purposes of compliance with the MATS rule. Idaho Power believes that as of the date of this report, the coal-fired plants are in compliance with the MATS rule. Legal challenges relating to the MATS rule, to which Idaho Power is not a party and pursuant to which the EPA is performing a court-mandated cost analysis for the rule, are pending.

***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 and pending actions related to certain of those items relevant to Idaho Power include the following:

- *$NO_X$*: 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 would 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.

- *$SO_2$*: 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. On October 1, 2015, the EPA issued a final rule lowering the national ozone standard under the CAA to 70 parts per billion. The EPA stated that the vast majority of U.S. counties will meet the standards by 2025 with federal and state rules and programs now in place or underway. The EPA's plan provides for finalizing non-attainment designations in 2017, and it plans to propose rules and guidance over the next year to help states with potential non-attainment areas implement the revised standards. Non-attainment areas will have until 2020 to late 2037 to meet the new standard, with attainment dates varying based on the ozone level in the area. Due to high levels of background ozone, which can be caused by factors such as elevation, vegetation, wildfire, and international transport, attainment in areas within the Intermountain West may be difficult, and the formulation of state implementation plans to bring an area into compliance with the new standard may be challenging due to the existence of ozone caused by factors outside of local control. If the EPA were to make non-attainment determinations in areas where Idaho Power owns or co-owns power plants, or proposes to construct power plants, the state implementation plan for those areas could result in changes to the nature and frequency of operation of existing generation plants and make more difficult or costly the construction of new power generation plants. Idaho Power will seek to work with state regulators on implementation plans for any non-attainment areas, in an effort to reduce the potential adverse impact on Idaho Power's operation of its existing power generation plants and construction of future facilities.

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 if areas in which Idaho Power operate, or adjacent areas, receive non-attainment designations.

***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. The RH BART rules would have required installation of a suite of emissions controls at the Boardman plant; however, in December 2010, the Oregon Environmental Quality Commission approved a plan to install a less costly suite of environmental controls and cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

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 required 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, which has been completed, 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, which was submitted in December 2017. 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. In January 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 regional haze 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.

**Clean Water Act Matters**

***Definition of "Waters of the United States" Under the CWA***: On August 28, 2015, the EPA's and U.S. Army Corps of Engineers' final rule defining the phrase "waters of the United States" under the CWA became effective (WOTUS Rule). Idaho Power believes that the final rule potentially expanded 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 WOTUS Rule was widely challenged in both federal district and circuit courts. The State of Idaho, and several other parties, challenged the rule in North Dakota federal court. That court held that it had jurisdiction and enjoined the implementation of the WOTUS Rule. In February 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to rescind the WOTUS Rule. In July 2017, the EPA and the U.S. Army Corps of Engineers issued a notice of their intent to rescind and replace the definition of "waters of the United States" under the CWA, which Idaho Power expects would reduce the number of waters in Idaho Power's service area subject to the WOTUS Rule. In November 2017, the EPA issued a notice that it will delay the effectiveness of the WOTUS Rule until 2020 while the U.S. Army Corps of Engineers considers a replacement rule. On January 22, 2018, the U.S. Supreme Court issued a unanimous ruling that challenges to the WOTUS Rule must begin with the federal district courts, effectively negating a nationwide stay issued by the Sixth Circuit in 2016. However, because the State of Idaho remains a party to the federal court action in North Dakota, that court's enjoinder remains in effect, meaning the WOTUS Rule currently does not apply to actions brought in Idaho.

Idaho Power has analyzed the WOTUS Rule and expects that, even if the WOTUS Rule is reinstated in Idaho, while it may cause Idaho Power to incur additional permitting, regulatory requirements, and other costs associated with the rule, the aggregate amount of increased costs is unlikely to have a material adverse effect on Idaho Power's operations or financial condition, in part due to the relatively arid climate of Idaho Power's service area. Similarly, because the CWA, as interpreted even prior to the WOTUS Rule, applies to most of Idaho Power's facilities, including its hydroelectric plants, Idaho Power does not expect this proposal to have a material benefit to Idaho Power's operations or financial condition.

***CWA Matters Related to Hydroelectric Relicensing:*** 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.

**Review of Federal Coal Leases**

In January 2016, the Secretary of the U.S. Department of the Interior issued an order directing the BLM to prepare a Programmatic Environmental Impact Statement (PEIS) to analyze potential reforms to the federal coal lease program and placed a moratorium on new federal coal leasing, with limited exceptions, pending completion of the PEIS. In January 2017, the Secretary of the Department of the Interior ordered a cessation of all work on the PEIS and in March 2017 lifted the moratorium on new federal coal leases. As of the date of this report, Idaho Power believes that BCC has adequate reserves under existing leases to satisfy its coal delivery obligations to the Jim Bridger plant during the term of the existing coal supply contract through 2024, and that the Jim Bridger plant will otherwise have access to sufficient coal supplies for its operation for the foreseeable future. However, the lifting of the moratorium could increase the availability of coal resources and lower the cost of leases for coal resources, which could reduce the fuel cost for each of Idaho Power's co-owned coal-fired plants.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with 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 area 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 approximately $1.1 billion of regulatory assets and $0.7 billion of regulatory liabilities at December 31, 2017. 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, which could have a material effect on Idaho Power's financial condition or results of operations.

Refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for additional information relating to regulatory matters.

### 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, 2017, with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2018 pension expense will be decreased to 3.95 percent from the 4.45 percent used in 2017.

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 2018 pension expense will be 7.5 percent, the same assumption as was used for 2017.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $50.4 million, $51.8 million, and $51.4 million for the years ended December 31, 2017, 2016, and 2015, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2018, gross pension and other postretirement benefit costs are expected to total approximately $48 million, which takes into account the change in the 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** | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| | **(millions of dollars)** | | | |
| Effect of 0.5% rate increase on net periodic benefit cost | $ (7.9) | $ (7.2) | $ (3.7) | $ (3.2) |
| Effect of 0.5% rate decrease on net periodic benefit cost | 8.8 | 7.9 | 3.6 | 3.2 |

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $84.7 million decrease in the combined benefit obligations of the plans as of December 31, 2017. A 0.5 percent decrease in the plans' discount rates would have resulted in an $95.7 million increase in the combined benefit obligations of the plans as of December 31, 2017.

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, 2017, a total of $127.7 million of expense was deferred as a regulatory asset. Approximately $20 million is expected to be deferred in 2018. Idaho Power recorded pension expense of approximately $19 million in 2017, 2016, and 2015.

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.

**RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS**

For a listing of new and recently adopted accounting standards, see Note 1 - "Summary of Significant Accounting Policies" to the notes to the consolidated financial statements included in this report.

## 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, 2017. IDACORP and Idaho Power have 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, 2017, IDACORP and Idaho Power had no net floating rate debt, as the carrying value of short-term investments exceeded the carrying value of outstanding variable-rate debt.

***Fixed Rate Debt*****:** As of December 31, 2017, both IDACORP and Idaho Power had $1.7 billion in fixed rate debt, with a fair market value of approximately $1.9 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 $260 million if market interest rates were to decline by one percentage point from their December 31, 2017, 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 power cost adjustment 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, 2017, Idaho Power had posted $0.9 million performance assurance collateral related to these contracts. 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, 2017, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $5 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 levels of 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 consolidated financial statements included in this report.

## 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, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars except for per share amounts) | | |
| **Operating Revenues:** | | | |
| Electric utility: | | | |
| General business | $ 1,205,976 | $ 1,145,993 | $ 1,151,038 |
| Off-system sales | 33,382 | 25,205 | 30,887 |
| Other revenues | 105,535 | 88,155 | 85,580 |
| Total electric utility revenues | 1,344,893 | 1,259,353 | 1,267,505 |
| Other | 4,593 | 2,667 | 2,784 |
| Total operating revenues | 1,349,486 | 1,262,020 | 1,270,289 |
| **Operating Expenses:** | | | |
| Electric utility: | | | |
| Purchased power | 248,950 | 245,764 | 226,470 |
| Fuel expense | 145,829 | 179,491 | 186,231 |
| Power cost adjustment | 52,024 | (5,330) | 16,766 |
| Other operations and maintenance | 349,725 | 351,893 | 342,146 |
| Energy efficiency programs | 39,241 | 33,754 | 30,532 |
| Depreciation | 162,091 | 143,661 | 138,110 |
| Taxes other than income taxes | 34,089 | 32,823 | 32,808 |
| Total electric utility expenses | 1,031,949 | 982,056 | 973,063 |
| Other | 13,186 | 8,188 | 15,129 |
| Total operating expenses | 1,045,135 | 990,244 | 988,192 |
| **Operating Income** | 304,351 | 271,776 | 282,097 |
| **Allowance for Equity Funds Used During Construction** | 20,784 | 22,031 | 21,785 |
| **Earnings of Unconsolidated Equity-Method Investments** | 11,374 | 12,871 | 11,128 |
| **Other Income, Net** | 9,085 | 9,874 | 7,159 |
| **Interest Expense:** | | | |
| Interest on long-term debt | 81,198 | 81,956 | 83,056 |
| Other interest | 11,242 | 10,273 | 8,922 |
| Allowance for borrowed funds used during construction | (8,694) | (10,194) | (10,044) |
| Total interest expense, net | 83,746 | 82,035 | 81,934 |
| **Income Before Income Taxes** | 261,848 | 234,517 | 240,235 |
| **Income Tax Expense** | 48,660 | 36,429 | 45,760 |
| **Net Income** | 213,188 | 198,088 | 194,475 |
| Adjustment for (income) loss attributable to noncontrolling interests | (769) | 200 | 204 |
| **Net Income Attributable to IDACORP, Inc.** | $ 212,419 | $ 198,288 | $ 194,679 |
| Weighted Average Common Shares Outstanding - Basic (000's) | 50,361 | 50,298 | 50,220 |
| Weighted Average Common Shares Outstanding - Diluted (000's) | 50,424 | 50,373 | 50,292 |
| **Earnings Per Share of Common Stock:** | | | |
| Earnings Attributable to IDACORP, Inc. - Basic | $ 4.22 | $ 3.94 | $ 3.88 |
| Earnings Attributable to IDACORP, Inc. - Diluted | $ 4.21 | $ 3.94 | $ 3.87 |

The accompanying notes are an integral part of these statements.

**IDACORP, Inc.**
**Consolidated Statements of Comprehensive Income**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | |
| **Net Income** | $ 213,188 | $ 198,088 | $ 194,475 |
| **Other Comprehensive Income:** | | | |
| Unfunded pension liability adjustment, net of tax of $(1,555), $253, and $1,851 | (5,990) | 394 | 2,882 |
| **Total Comprehensive Income** | 207,198 | 198,482 | 197,357 |
| Comprehensive (income) loss attributable to noncontrolling interests | (769) | 200 | 204 |
| **Comprehensive Income Attributable to IDACORP, Inc.** | $ 206,429 | $ 198,682 | $ 197,561 |

The accompanying notes are an integral part of these statements.

**IDACORP, Inc.**
**Consolidated Balance Sheets**

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | (in thousands) | |
| **Assets** | | |
| **Current Assets:** | | |
| Cash and cash equivalents | $ 76,649 | $ 61,480 |
| Receivables: | | |
| Customer (net of allowance of $2,013 and $968, respectively) | 75,249 | 71,557 |
| Other (net of allowance of $180 and $164, respectively) | 30,438 | 15,280 |
| Income taxes receivable | 8,147 | 12,781 |
| Accrued unbilled revenues | 75,120 | 80,738 |
| Materials and supplies (at average cost) | 55,745 | 57,858 |
| Fuel stock (at average cost) | 56,638 | 53,698 |
| Prepayments | 16,984 | 18,389 |
| Current regulatory assets | 48,613 | 62,570 |
| Other | 18 | 5,961 |
| Total current assets | 443,601 | 440,312 |
| **Investments** | 115,698 | 125,164 |
| **Property, Plant and Equipment:** | | |
| Utility plant in service | 5,906,162 | 5,732,044 |
| Accumulated provision for depreciation | (2,098,274) | (1,988,477) |
| Utility plant in service - net | 3,807,888 | 3,743,567 |
| Construction work in progress | 452,424 | 405,069 |
| Utility plant held for future use | 8,075 | 7,441 |
| Other property, net of accumulated depreciation | 15,488 | 15,922 |
| Property, plant and equipment - net | 4,283,875 | 4,171,999 |
| **Other Assets:** | | |
| Company-owned life insurance | 59,323 | 57,553 |
| Regulatory assets | 1,083,483 | 1,409,329 |
| Long-term receivables (net of allowance of $402) | 4,307 | 23,482 |
| Other | 55,118 | 62,058 |
| Total other assets | 1,202,231 | 1,552,422 |
| **Total** | $ 6,045,405 | $ 6,289,897 |

The accompanying notes are an integral part of these statements.

**IDACORP, Inc.**
**Consolidated Balance Sheets**

| | December 31, | |
|---|---|---|
| | **2017** | **2016** |
| | (in thousands) | |
| **Liabilities and Equity** | | |
| **Current Liabilities:** | | |
| Current maturities of long-term debt | $ — | $ 1,064 |
| Notes payable | — | 21,800 |
| Accounts payable | 90,277 | 106,194 |
| Taxes accrued | 11,075 | 11,348 |
| Interest accrued | 22,379 | 22,377 |
| Accrued compensation | 47,018 | 45,787 |
| Current regulatory liabilities | 1,404 | 9,944 |
| Advances from customers | 18,414 | 21,438 |
| Other | 10,182 | 9,763 |
| Total current liabilities | 200,749 | 249,715 |
| **Other Liabilities:** | | |
| Deferred income taxes | 660,940 | 1,244,250 |
| Regulatory liabilities | 698,044 | 436,845 |
| Pension and other postretirement benefits | 438,869 | 411,523 |
| Other | 44,566 | 45,084 |
| Total other liabilities | 1,842,419 | 2,137,702 |
| **Long-Term Debt** | 1,746,123 | 1,744,614 |
| **Commitments and Contingencies** | | |
| **Equity:** | | |
| IDACORP, Inc. shareholders' equity: | | |
| Common stock, no par value (120,000 shares authorized; shares issued 50,420) | 857,207 | 851,833 |
| Retained earnings | 1,426,528 | 1,323,198 |
| Accumulated other comprehensive loss | (30,964) | (20,882) |
| Treasury stock (28 and 23 shares at cost, respectively) | (1,386) | (243) |
| Total IDACORP, Inc. shareholders' equity | 2,251,385 | 2,153,906 |
| Noncontrolling interests | 4,729 | 3,960 |
| Total equity | 2,256,114 | 2,157,866 |
| **Total** | $ 6,045,405 | $ 6,289,897 |

The accompanying notes are an integral part of these statements.

**IDACORP, Inc.**
**Consolidated Statements of Cash Flows**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | |
| **Operating Activities:** | | | |
| Net income | $ 213,188 | $ 198,088 | $ 194,475 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 165,933 | 147,294 | 142,581 |
| Deferred income taxes and investment tax credits | 33,245 | 35,732 | 38,645 |
| Changes in regulatory assets and liabilities | 57,131 | (5,650) | 13,699 |
| Pension and postretirement benefit plan expense | 28,911 | 29,581 | 30,207 |
| Contributions to pension and postretirement benefit plans | (46,589) | (45,301) | (42,843) |
| Earnings of unconsolidated equity-method investments | (11,374) | (12,871) | (11,128) |
| Distributions from unconsolidated equity-method investments | 24,975 | 25,641 | 12,458 |
| Allowance for equity funds used during construction | (20,784) | (22,031) | (21,785) |
| Gain on sale of investments and assets | (131) | (103) | (97) |
| Other non-cash adjustments to net income, net | 8,454 | 5,108 | 2,788 |
| Change in: | | | |
| Accounts receivable | 4,005 | (2,671) | 4,740 |
| Accounts payable and other accrued liabilities | (17,208) | 13,300 | 2,440 |
| Taxes accrued/receivable | 4,361 | 662 | 818 |
| Other current assets | 2,814 | (10,887) | (14,861) |
| Other current liabilities | 1,017 | (3,283) | 403 |
| Other assets | (8,835) | (3,897) | 3,021 |
| Other liabilities | (1,093) | (1,006) | (2,367) |
| Net cash provided by operating activities | 438,020 | 347,706 | 353,194 |
| **Investing Activities:** | | | |
| Additions to property, plant and equipment | (285,488) | (296,950) | (294,021) |
| Payments received from transmission project joint funding partners | 6,074 | 7,586 | 11,377 |
| Purchase of available-for-sale securities | (11,356) | (14,917) | (14,106) |
| Proceeds from sale of available-for-sale securities | 4,989 | 15,693 | 34,243 |
| Purchase of life insurance investment | — | (10,000) | (30,000) |
| Other | 2,481 | 1,144 | 801 |
| Net cash used in investing activities | (283,300) | (297,444) | (291,706) |
| **Financing Activities:** | | | |
| Issuance of long-term debt | — | 120,000 | 250,000 |
| Retirement of long-term debt | (1,064) | (101,064) | (121,064) |
| Dividends on common stock | (113,127) | (104,984) | (96,810) |
| Net change in short-term borrowings | (21,800) | 1,800 | (11,300) |
| Acquisition of treasury stock | (3,212) | (3,329) | (3,277) |
| Make-whole premium on retirement of long-term debt | — | (13,895) | (17,872) |
| Other | (348) | (2,112) | (3,171) |
| Net cash used in financing activities | (139,551) | (103,584) | (3,494) |
| Net increase (decrease) in cash and cash equivalents | 15,169 | (53,322) | 57,994 |
| Cash and cash equivalents at beginning of the year | 61,480 | 114,802 | 56,808 |
| Cash and cash equivalents at end of the year | $ 76,649 | $ 61,480 | $ 114,802 |
| **Supplemental Disclosure of Cash Flow Information:** | | | |
| Cash paid during the year for: | | | |
| Income taxes | $ 14,742 | $ 3,302 | $ 8,857 |
| Interest (net of amount capitalized) | $ 80,004 | $ 78,334 | $ 79,442 |
| Non-cash investing activities: | | | |
| Additions to property, plant and equipment in accounts payable | $ 33,220 | $ 34,603 | $ 23,840 |

The accompanying notes are an integral part of these statements.

**IDACORP, Inc.**
**Consolidated Statements of Equity**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | |
| **Common Stock:** | | | |
| Balance at beginning of year | $ 851,833 | $ 849,112 | $ 845,402 |
| Cumulative effect of change in accounting principle | — | 234 | — |
| Share-based compensation expense and other | 5,374 | 2,487 | 3,710 |
| Balance at end of year | 857,207 | 851,833 | 849,112 |
| **Retained Earnings:** | | | |
| Balance at beginning of year | 1,323,198 | 1,230,105 | 1,132,237 |
| Cumulative effect of change in accounting principle | 4,092 | (234) | — |
| Net income attributable to IDACORP, Inc. | 212,419 | 198,288 | 194,679 |
| Common stock dividends ($2.24, $2.08, and $1.92 per share, respectively) | (113,181) | (104,961) | (96,811) |
| Balance at end of year | 1,426,528 | 1,323,198 | 1,230,105 |
| **Accumulated Other Comprehensive (Loss) Income:** | | | |
| Balance at beginning of year | (20,882) | (21,276) | (24,158) |
| Cumulative effect of change in accounting principle | (4,092) | — | — |
| Unfunded pension liability adjustment (net of tax) | (5,990) | 394 | 2,882 |
| Balance at end of year | (30,964) | (20,882) | (21,276) |
| **Treasury Stock:** | | | |
| Balance at beginning of year | (243) | (57) | (280) |
| Issued | 2,069 | 3,143 | 3,500 |
| Acquired | (3,212) | (3,329) | (3,277) |
| Balance at end of year | (1,386) | (243) | (57) |
| Total IDACORP, Inc. shareholders’ equity at end of year | 2,251,385 | 2,153,906 | 2,057,884 |
| **Noncontrolling Interests:** | | | |
| Balance at beginning of year | 3,960 | 4,160 | 4,364 |
| Net income (loss) attributable to noncontrolling interests | 769 | (200) | (204) |
| Balance at end of year | 4,729 | 3,960 | 4,160 |
| Total equity at end of year | $ 2,256,114 | $ 2,157,866 | $ 2,062,044 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Statements of Income**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| | (thousands of dollars) | | |
| **Operating Revenues:** | | | |
| General business | $ 1,205,976 | $ 1,145,993 | $ 1,151,038 |
| Off-system sales | 33,382 | 25,205 | 30,887 |
| Other revenues | 105,535 | 88,155 | 85,580 |
| Total operating revenues | 1,344,893 | 1,259,353 | 1,267,505 |
| **Operating Expenses:** | | | |
| Operation: | | | |
| Purchased power | 248,950 | 245,764 | 226,470 |
| Fuel expense | 145,829 | 179,491 | 186,231 |
| Power cost adjustment | 52,024 | (5,330) | 16,766 |
| Other operations and maintenance | 349,725 | 351,893 | 342,146 |
| Energy efficiency programs | 39,241 | 33,754 | 30,532 |
| Depreciation | 162,091 | 143,661 | 138,110 |
| Taxes other than income taxes | 34,089 | 32,823 | 32,808 |
| Total operating expenses | 1,031,949 | 982,056 | 973,063 |
| **Income from Operations** | 312,944 | 277,297 | 294,442 |
| **Other Income (Expense):** | | | |
| Allowance for equity funds used during construction | 20,784 | 22,031 | 21,785 |
| Earnings of unconsolidated equity-method investments | 9,267 | 10,855 | 9,773 |
| Other expense, net | (1,726) | (1,944) | (5,071) |
| Total other income | 28,325 | 30,942 | 26,487 |
| **Interest Charges:** | | | |
| Interest on long-term debt | 81,198 | 81,956 | 83,056 |
| Other interest | 11,156 | 10,050 | 8,706 |
| Allowance for borrowed funds used during construction | (8,694) | (10,194) | (10,044) |
| Total interest charges | 83,660 | 81,812 | 81,718 |
| **Income Before Income Taxes** | 257,609 | 226,427 | 239,211 |
| **Income Tax Expense** | 51,262 | 37,185 | 48,228 |
| **Net Income** | $ 206,347 | $ 189,242 | $ 190,983 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Statements of Comprehensive Income**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| | (thousands of dollars) | | |
| **Net Income** | $ 206,347 | $ 189,242 | $ 190,983 |
| **Other Comprehensive Income:** | | | |
| Unfunded pension liability adjustment, net of tax of $(1,555), $253, and $1,851 | (5,990) | 394 | 2,882 |
| **Total Comprehensive Income** | $ 200,357 | $ 189,636 | $ 193,865 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Balance Sheets**

| | December 31, | |
|---|---|---|
| | **2017** | **2016** |
| | (in thousands) | |
| **Assets** | | |
| **Electric Plant:** | | |
| In service (at original cost) | $ 5,906,162 | $ 5,732,044 |
| Accumulated provision for depreciation | (2,098,274) | (1,988,477) |
| In service - net | 3,807,888 | 3,743,567 |
| Construction work in progress | 452,424 | 405,069 |
| Held for future use | 8,075 | 7,441 |
| Electric plant - net | 4,268,387 | 4,156,077 |
| **Investments and Other Property** | 99,904 | 107,379 |
| **Current Assets:** | | |
| Cash and cash equivalents | 44,646 | 44,140 |
| Receivables: | | |
| Customer (net of allowance of $2,013 and $968, respectively) | 75,249 | 71,557 |
| Other (net of allowance of $180 and $164, respectively) | 30,274 | 7,555 |
| Income taxes receivable | 26,492 | 23,334 |
| Accrued unbilled revenues | 75,120 | 80,738 |
| Materials and supplies (at average cost) | 55,745 | 57,858 |
| Fuel stock (at average cost) | 56,638 | 53,698 |
| Prepayments | 16,866 | 18,270 |
| Current regulatory assets | 48,613 | 62,570 |
| Other | 18 | 5,962 |
| Total current assets | 429,661 | 425,682 |
| **Deferred Debits:** | | |
| Company-owned life insurance | 59,323 | 57,553 |
| Regulatory assets | 1,083,483 | 1,409,329 |
| Long-term receivables | 503 | 19,677 |
| Other | 54,174 | 61,047 |
| Total deferred debits | 1,197,483 | 1,547,606 |
| **Total** | $ 5,995,435 | $ 6,236,744 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Balance Sheets**

| | December 31, | |
|---|---|---|
| | **2017** | **2016** |
| | (in thousands) | |
| **Capitalization and Liabilities** | | |
| **Capitalization:** | | |
| Common stock equity: | | |
| Common stock, $2.50 par value (50,000 shares authorized; 39,151 shares outstanding) | $ 97,877 | $ 97,877 |
| Premium on capital stock | 712,258 | 712,258 |
| Capital stock expense | (2,097) | (2,097) |
| Retained earnings | 1,308,702 | 1,211,547 |
| Accumulated other comprehensive loss | (30,964) | (20,882) |
| Total common stock equity | 2,085,776 | 1,998,703 |
| Long-term debt | 1,746,123 | 1,744,614 |
| Total capitalization | 3,831,899 | 3,743,317 |
| **Current Liabilities:** | | |
| Current maturities of long-term debt | — | 1,064 |
| Notes payable | — | 21,800 |
| Accounts payable | 89,978 | 105,846 |
| Accounts payable to affiliates | 57,562 | 1,056 |
| Taxes accrued | 10,904 | 11,348 |
| Interest accrued | 22,379 | 22,377 |
| Accrued compensation | 46,832 | 45,622 |
| Current regulatory liabilities | 1,404 | 9,944 |
| Advances from customers | 18,414 | 21,438 |
| Other | 9,556 | 9,103 |
| Total current liabilities | 257,029 | 249,598 |
| **Deferred Credits:** | | |
| Deferred income taxes | 725,942 | 1,351,415 |
| Regulatory liabilities | 698,044 | 436,845 |
| Pension and other postretirement benefits | 438,869 | 411,523 |
| Other | 43,652 | 44,046 |
| Total deferred credits | 1,906,507 | 2,243,829 |
| **Commitments and Contingencies** | | |
| **Total** | $ 5,995,435 | $ 6,236,744 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Statements of Cash Flows**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | |
| **Operating Activities:** | | | |
| Net income | $ 206,347 | $ 189,242 | $ 190,983 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 165,337 | 146,694 | 141,972 |
| Deferred income taxes and investment tax credits | (10,875) | 25,780 | 25,702 |
| Changes in regulatory assets and liabilities | 57,131 | (5,651) | 13,699 |
| Pension and postretirement benefit plan expense | 28,894 | 29,597 | 30,185 |
| Contributions to pension and postretirement benefit plans | (46,573) | (45,317) | (42,821) |
| Earnings of unconsolidated equity-method investments | (9,267) | (10,855) | (9,773) |
| Distributions from unconsolidated equity-method investments | 23,000 | 23,716 | 10,833 |
| Allowance for equity funds used during construction | (20,784) | (22,031) | (21,785) |
| Gain on sale of investments and assets | (131) | (103) | (97) |
| Other non-cash adjustments to net income, net | 1,069 | (454) | (687) |
| Change in: | | | |
| Accounts receivable | (2,321) | 3,590 | 1,998 |
| Accounts payable | 38,111 | 13,308 | 2,646 |
| Taxes accrued/receivable | (3,601) | (17,299) | 17,179 |
| Other current assets | 2,812 | (10,902) | (14,849) |
| Other current liabilities | 996 | (3,322) | 443 |
| Other assets | (8,835) | (3,897) | 3,021 |
| Other liabilities | (967) | (829) | (2,222) |
| Net cash provided by operating activities | 420,343 | 311,267 | 346,427 |
| **Investing Activities:** | | | |
| Additions to utility plant | (285,471) | (296,948) | (293,968) |
| Payments received from transmission project joint funding partners | 6,074 | 7,586 | 11,377 |
| Purchase of available-for-sale securities | (11,356) | (14,917) | (14,106) |
| Proceeds from the sale of available-for-sale securities | 4,989 | 15,693 | 34,243 |
| Purchase of life insurance investment | — | (10,000) | (30,000) |
| Other | 2,316 | 1,000 | 706 |
| Net cash used in investing activities | (283,448) | (297,586) | (291,748) |
| **Financing Activities:** | | | |
| Issuance of long-term debt | — | 120,000 | 250,000 |
| Retirement of long-term debt | (1,064) | (101,064) | (121,064) |
| Dividends on common stock | (113,284) | (105,121) | (96,907) |
| Net change in short term borrowings | (21,800) | 21,800 | — |
| Make-whole premium on retirement of long-term debt | — | (13,895) | (17,872) |
| Other | (241) | (2,017) | (4,775) |
| Net cash (used in) provided by financing activities | (136,389) | (80,297) | 9,382 |
| Net increase (decrease) in cash and cash equivalents | 506 | (66,616) | 64,061 |
| Cash and cash equivalents at beginning of the year | 44,140 | 110,756 | 46,695 |
| Cash and cash equivalents at end of the year | $ 44,646 | $ 44,140 | $ 110,756 |
| **Supplemental Disclosure of Cash Flow Information:** | | | |
| Cash paid to IDACORP related to income taxes | $ 12,444 | $ 29,341 | $ 7,487 |
| Cash paid for interest (net of amount capitalized) | $ 79,918 | $ 78,111 | $ 79,226 |
| Non-cash investing activities: | | | |
| Additions to property, plant and equipment in accounts payable | $ 33,220 | $ 34,603 | $ 23,840 |

The accompanying notes are an integral part of these statements.

**Idaho Power Company**
**Consolidated Statements of Retained Earnings**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | |
| **Retained Earnings, Beginning of Year** | $ 1,211,547 | $ 1,127,426 | $ 1,033,350 |
| Net Income | 206,347 | 189,242 | 190,983 |
| Dividends on Common Stock | (113,284) | (105,121) | (96,907) |
| Cumulative Effect of Change in Accounting Principle | 4,092 | — | — |
| **Retained Earnings, End of Year** | $ 1,308,702 | $ 1,211,547 | $ 1,127,426 |

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, these 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 engaged in the generation, transmission, distribution, sales, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the state utility regulatory commissions of Idaho and Oregon and the Federal Energy Regulatory Commission (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.

IDACORP's other significant wholly-owned subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments, and 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).

### Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the assets, liabilities, revenues and expenses of each company and its wholly-owned subsidiaries listed above, as well as any variable interest entities (VIEs) for which the respective company is the primary beneficiary. 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.

IDACORP also consolidates one variable interest entity (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, 2017, Marysville had approximately $18 million of assets, primarily a hydroelectric plant, and approximately $9 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 from Marysville and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is identified as the primary beneficiary because the combination of its ownership interest in the joint venture with the intercompany note and the EEC note result in Ida-West's ability to control the activities of the joint venture. 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 $68.6 million at December 31, 2017, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $56.7 million guarantee for mine reclamation costs, which is discussed further in Note 9 - "Commitments."

IFS's affordable housing limited partnership and other real estate investments are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 2 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 $5.5 million at December 31, 2017.

Ida-West's other investments in PURPA facilities, BCC, and IFS's investments are accounted for under the equity method of accounting (see Note 14 - "Investments").

Except for amounts related to sales of electricity by Ida-West's PURPA projects to Idaho Power, all intercompany transactions and balances have been eliminated in consolidation.

The accompanying consolidated financial statements include Idaho Power's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 12 - "Property, Plant and Equipment").

**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 or accrued 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 - "Regulatory Matters."

**Management Estimates**

Management makes estimates and assumptions when preparing financial statements in conformity with generally accepted accounting principles. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, 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. Accordingly, 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.

**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.

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, 2017 and 2016. 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 does not report any collections of franchise fees and similar taxes related to energy consumption on the income statement. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 - "Regulatory Matters" for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho; and
- collection in base rates of 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 deferred 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 2.9 percent in 2017, 2.6 percent in 2016, and 2.7 percent in 2015.

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. 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 long-lived assets in 2017, 2016, or 2015.

**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 7.6 percent for 2017, 2016 and 2015.

**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 - "Income Taxes."

**Other Accounting Policies**

Debt discount, expense, and premium are deferred and amortized over the terms of the respective debt issues. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

**Supplemental Cash Flows Information**

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million. Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged. Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

**Reclassifications**

In these consolidated financial statements, certain amounts in prior periods' consolidated financial statements have been reclassified to conform with current period presentation. On both IDACORP's and Idaho Power's 2016 consolidated balance sheets, the $9.5 million of American Falls and Milner water rights which had previously been reported separately was reclassified to "Other" within Other Assets and Deferred Debits, respectively. Also, on Idaho Power's 2016 consolidated balance sheet, $19.7 million was reclassified from "Other" in other assets to the newly created "Long-term receivables" within Deferred Debits.

**New and Recently Adopted Accounting Pronouncements**

*Recently Adopted Accounting Pronouncements*

In February 2018, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*, which permits a reclassification from Accumulated Other Comprehensive Income (AOCI) to retained earnings for the stranded tax effects resulting from the decrease in corporate tax rate from the enactment in December 2017 of a tax reform act, generally referred to as the “Tax Cuts and Jobs Act.” For more information on other impacts of the Tax Cuts and Jobs Act, see Note 2 - "Income Taxes." As permitted by the FASB, IDACORP and Idaho Power elected to early adopt the provisions of the new standard at December 31, 2017, resulting in a $4.1 million cumulative effect adjustment for a change in accounting principle to both AOCI and retained earnings. The amount relates to stranded tax effects in AOCI resulting from the Tax Cuts and Jobs Act related to annual valuation adjustments for two nonqualified defined benefit pension plans.

*Recent Accounting Pronouncements Not Yet Adopted*

In May 2014, the FASB issued 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 FASB amended certain aspects of ASU 2014-09 to clarify the implementation guidance, including clarifications related to principal versus agent considerations, licensing and identifying performance obligations, narrow scope improvements, and practical expedients. The companies have assessed the impacts of ASU 2014-09 on their financial statements and have concluded the new guidance will not affect the timing and amount of revenue recognized. However, the presentation and disclosure requirements of the standard will result in a change in the presentation of revenue on the companies' consolidated statements of income as well as expanded disclosures around the disaggregation of revenue, performance obligations, and transaction price. The guidance in ASU 2014-09 is effective for interim and annual reporting periods beginning after December 15, 2017. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years (full retrospective approach) and the other requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under previous standards (modified-retrospective approach). IDACORP and Idaho Power will adopt ASU 2014-09 on January 1, 2018, using the modified-retrospective approach. As the standard does not change the timing and amount of revenue recognized for the companies, no cumulative-effect adjustment is required.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities*, which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. IDACORP and Idaho Power concluded the adoption will not have a material impact on their financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* intended to improve financial reporting about leasing transactions. The ASU significantly changes the accounting model used by lessees to account for leases, requiring that all material leases be presented on the balance sheet. Under the current model, some leases are classified as capital leases and recorded on the balance sheet while other leases classified as operating leases are not recognized on the balance sheet. The new standard is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted. The standard must be adopted using a modified-retrospective approach. IDACORP and Idaho Power are evaluating the impact of ASU 2016-02 on their financial statements. Specifically, the companies are considering whether the new guidance will affect their accounting for purchase power agreements, easements and rights-of-way, utility pole attachments, and other utility industry-related arrangements. At this time, the companies do not know, and cannot reasonably estimate, the dollar impact of the adoption.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230)*, which amends ASC 230 to clarify guidance on the classification of certain cash receipts and payments in the statement of cash flows. The FASB issued the ASU with the intent of reducing diversity in practice with respect to eight types of cash flows. The companies expect the ASU to affect the classification of proceeds from the settlement of corporate-owned life insurance policies and related costs, which will be classified as investing activities under the new guidance. The companies already present debt prepayment and extinguishment costs, proceeds from the settlement of insurance claims (other than corporate-owned life insurance), and distributions received from equity-method investments in accordance with the new guidance. ASU 2016-15 is effective for interim and annual reporting periods beginning after December 15, 2017. The standard must be adopted retrospectively to all periods presented, unless impracticable to do so. IDACORP and Idaho Power do not believe the adoption will have a material impact on their financial statements.

In March 2017, the FASB issued ASU 2017-07, *Compensation -- Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*, which requires employers to disaggregate the service cost component from other components of net periodic benefit costs and to disclose the amounts of net periodic benefit costs that are included in each income statement line item. The standard requires employers to present the service cost component in the same line item as other compensation costs and to present the other components of net periodic benefit costs (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income. In addition, only the service cost component is eligible for capitalization. Idaho Power currently capitalizes amounts of pension or postretirement costs that are insignificant to the consolidated financial statements. The amendments in ASU 2017-07 are effective for interim and annual reporting periods beginning after December 15, 2017. Entities must use (1) a retrospective transition method to adopt the requirement for separate presentation in the income statement of service costs and other components and (2) a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service cost component. While ASU 2017-07 will result in changes to the classification of the other components of net periodic benefit costs on the consolidated statements of income of IDACORP and Idaho Power, the new standard will not materially affect the consolidated financial statements of the companies.

## 2. INCOME TAXES

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

| | IDACORP | | | Idaho Power | | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| | | | (thousands of dollars) | | | |
| Federal income tax expense at 35% statutory rate | $ 91,378 | $ 82,151 | $ 84,154 | $ 90,163 | $ 79,250 | $ 83,724 |
| Change in taxes resulting from: | | | | | | |
| AFUDC | (10,318) | (11,278) | (11,140) | (10,318) | (11,278) | (11,140) |
| Capitalized interest | 1,513 | 2,000 | 2,693 | 1,513 | 2,000 | 2,693 |
| Investment tax credits | (3,081) | (2,922) | (2,963) | (3,081) | (2,922) | (2,963) |
| Removal costs | (6,280) | (5,559) | (4,807) | (6,280) | (5,559) | (4,807) |
| Capitalized overhead costs | (11,200) | (10,500) | (8,750) | (11,200) | (10,500) | (8,750) |
| Capitalized repair costs | (28,700) | (28,000) | (28,700) | (28,700) | (28,000) | (28,700) |
| Bond redemption costs | — | (4,997) | (6,459) | — | (4,997) | (6,459) |
| Remeasurement of deferred taxes | 1,690 | — | — | 1,970 | — | — |
| State income taxes, net of federal benefit | 8,153 | 5,071 | 7,343 | 8,108 | 4,880 | 7,503 |
| Depreciation | 18,953 | 18,673 | 17,149 | 18,953 | 18,673 | 17,149 |
| Share-based compensation | (1,508) | (1,614) | — | (1,483) | (1,583) | — |
| Affordable housing tax credits | (2,559) | (2,579) | (3,258) | — | — | — |
| Affordable housing investment distributions | (1,124) | (1,717) | — | — | — | — |
| Affordable housing investment amortization | 1,271 | 1,380 | 1,519 | — | — | — |
| Other, net | (9,528) | (3,680) | (1,021) | (8,383) | (2,779) | (22) |
| Total income tax expense | $ 48,660 | $ 36,429 | $ 45,760 | $ 51,262 | $ 37,185 | $ 48,228 |
| Effective tax rate | 18.6% | 15.5% | 19.0% | 19.9% | 16.4% | 20.2% |

The items comprising income tax expense are as follows:

| | IDACORP | | | Idaho Power | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| | (thousands of dollars) | | | | | |
| **Income taxes current:** | | | | | | |
| Federal | $ 11,726 | $ 1,181 | $ 4,831 | $ 51,575 | $ 7,639 | $ 16,470 |
| State | 5,418 | 2,158 | 2,704 | 10,562 | 3,766 | 6,056 |
| Total | 17,144 | 3,339 | 7,535 | 62,137 | 11,405 | 22,526 |
| **Income taxes deferred:** | | | | | | |
| Federal | 24,018 | 33,205 | 34,770 | (13,002) | 27,506 | 27,696 |
| State | (154) | 100 | 626 | (5,298) | (2,031) | (2,486) |
| Total | 23,864 | 33,305 | 35,396 | (18,300) | 25,475 | 25,210 |
| **Investment tax credits:** | | | | | | |
| Deferred | 10,506 | 3,227 | 3,455 | 10,506 | 3,227 | 3,455 |
| Restored | (3,081) | (2,922) | (2,963) | (3,081) | (2,922) | (2,963) |
| Total | 7,425 | 305 | 492 | 7,425 | 305 | 492 |
| **Affordable housing investments** | 227 | (520) | 2,337 | — | — | — |
| Total income tax expense | $ 48,660 | $ 36,429 | $ 45,760 | $ 51,262 | $ 37,185 | $ 48,228 |

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

| | IDACORP | | Idaho Power | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| | (thousands of dollars) | | | |
| **Deferred tax assets:** | | | | |
| Regulatory liabilities | $ 98,744 | $ 51,326 | $ 98,744 | $ 51,326 |
| Deferred compensation | 21,066 | 29,490 | 21,025 | 29,424 |
| Deferred revenue | 31,086 | 40,354 | 31,086 | 40,354 |
| Tax credits | 109,673 | 142,627 | 44,106 | 33,589 |
| Partnership investments | 3,540 | 6,543 | — | — |
| Retirement benefits | 94,493 | 132,362 | 94,493 | 132,362 |
| Other | 8,636 | 11,401 | 8,435 | 11,069 |
| Total | 367,238 | 414,103 | 297,889 | 298,124 |
| **Deferred tax liabilities:** | | | | |
| Property, plant and equipment | 306,002 | 500,987 | 306,002 | 500,987 |
| Regulatory assets | 584,329 | 948,540 | 584,329 | 948,540 |
| Power cost adjustments | — | 21,077 | — | 21,077 |
| Fixed cost adjustment | 8,016 | 17,376 | 8,016 | 17,376 |
| Partnership investments | 5,182 | 12,371 | 980 | 5,554 |
| Retirement benefits | 103,407 | 140,083 | 103,407 | 140,083 |
| Other | 21,242 | 17,919 | 21,097 | 15,922 |
| Total | 1,028,178 | 1,658,353 | 1,023,831 | 1,649,539 |
| Net deferred tax liabilities | $ 660,940 | $ 1,244,250 | $ 725,942 | $ 1,351,415 |

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 and are reported as taxes accrued or income taxes receivable, respectively, on the consolidated balance sheets of Idaho Power. See Note 1 - "Summary of Significant Accounting Policies" for further discussion of accounting policies related to income taxes.

**Tax Credit Carryforwards**

As of December 31, 2017, IDACORP had $72.0 million of general business credit carryforwards for federal income tax purposes and $37.7 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2026 to 2037, and the Idaho investment tax credit expires from 2022 to 2031.

**Uncertain Tax Positions**

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2017 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 2017 for federal and 2013-2017 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 2017, the IRS completed its examination of IDACORP's 2016 tax year with no unresolved income tax issues.

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reforms the Internal Revenue Code of 1986, as amended. Effective January 1, 2018, the Tax Cuts and Jobs Act permanently lowers the corporate tax rate to 21 percent from the existing maximum rate of 35 percent, provides for expanded bonus depreciation, limits the deductibility of interest expense, eliminates alternative minimum tax, repeals the manufacturing deduction, and imposes additional limitations on the deductibility of executive compensation. Public utility companies, such as Idaho Power, retain the full deductibility of interest expense and are excluded from the bonus depreciation provisions; however, traditional accelerated tax depreciation methods are still available.

Due to the enactment of the Tax Cuts and Jobs Act and following generally accepted accounting principles, at December 31, 2017, IDACORP and Idaho Power remeasured all deferred income tax assets and liabilities. The effects of these adjustments resulted in a net tax expense as shown in the rate reconciliation table above. Additionally, as shown in the deferred income tax table above, the net deferred tax liabilities at both companies decreased significantly. Idaho Power's regulatory asset deferred income tax liability item decreased as the related regulatory asset was reduced in two primary ways: 1) the decrease in the federal income tax rate decreased the future cost to customers for funding the net deferred income tax liabilities resulting from the cumulative impacts of using the flow-through income tax accounting method for regulatory purposes and 2) the decrease in the federal income tax rate also reduced the net-to-gross multiplier that increases the regulatory asset to a revenue requirement carrying value. The change in income tax law also reduced the deferred income tax liability for depreciation-related timing differences under the normalized tax accounting method. As this reduction will flow back to customers in the future under the statutorily prescribed average rate assumption method, it was recorded as a regulatory liability on the consolidated balance sheets of the companies. See Note 3 - "Regulatory Matters" for more information.

The 2017 consolidated financial statements reflect the implementation of federal income tax reform as enacted and current regulatory policies. Additional adjustments may be required in future periods based upon technical corrections to the federal law, changes to state income tax policies, additional technical guidance from tax authorities, or orders from Idaho Power's regulators.

## 3. REGULATORY MATTERS

IDACORP’s and Idaho Power’s financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters.

**Regulatory Assets and Liabilities**

The application of accounting principles related to regulated operations sometimes results in Idaho Power recording some 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):

| Description | Remaining Amortization Period | As of December 31, 2017 Earning a Return[1] | As of December 31, 2017 Not Earning a Return | Total as of December 31, 2017 | Total as of December 31, 2016 |
|---|---|---|---|---|---|
| **Regulatory Assets:** | | | | | |
| Income taxes [2] | | $ — | $ 584,329 | $ 584,329 | $ 948,540 |
| Unfunded postretirement benefits[3] | | — | 280,166 | 280,166 | 263,779 |
| Pension expense deferrals | | 104,688 | 23,033 | 127,721 | 105,352 |
| Energy efficiency program costs[4] | | 6,273 | — | 6,273 | 5,552 |
| Power supply costs[5] | 2018-2019 | 3,137 | — | 3,137 | 53,870 |
| Fixed cost adjustment[5] | 2018-2019 | 30,856 | — | 30,856 | 44,445 |
| Valmy Plant settlement stipulation[5] | 2018-2028 | 43,351 | 1,282 | 44,633 | — |
| Asset retirement obligations[6] | | — | 15,767 | 15,767 | 14,154 |
| Long-term service agreement | 2018-2043 | 16,778 | 11,129 | 27,907 | 29,081 |
| Other | 2018-2055 | 5,687 | 5,620 | 11,307 | 7,126 |
| Total | | $ 210,770 | $ 921,326 | $ 1,132,096 | $ 1,471,899 |
| **Regulatory Liabilities:** | | | | | |
| Income taxes[7] | | $ — | $ 98,744 | $ 98,744 | $ 51,326 |
| Depreciation-related excess deferred income taxes[8] | | 193,991 | — | 193,991 | — |
| Removal costs[6] | | — | 184,993 | 184,993 | 186,609 |
| Investment tax credits | | — | 87,385 | 87,385 | 79,960 |
| Deferred revenue-AFUDC[9] | | 82,440 | 37,226 | 119,666 | 103,219 |
| Energy efficiency program costs[4] | | 408 | — | 408 | 10,730 |
| Power supply costs[5] | 2018-2019 | 5,443 | — | 5,443 | — |
| Mark-to-market assets[10] | | — | 22 | 22 | 7,831 |
| Other | | 5,805 | 2,991 | 8,796 | 7,114 |
| Total | | $ 288,087 | $ 411,361 | $ 699,448 | $ 446,789 |

(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 flow-through income tax accounting differences which have a corresponding deferred tax liability disclosed in Note 2 - "Income Taxes." The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For timing differences under the flow-through income tax accounting method, this reduction also reduces the associated regulatory assets generally recoverable over the remaining lives of the associated depreciable property.
(3) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11 - "Benefit Plans."
(4) The energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance.
(5) This item is discussed in more detail in this Note 3 - "Regulatory Matters."
(6) Asset retirement obligations and removal costs are discussed in Note 13 - "Asset Retirement Obligations."
(7) Represents the tax gross-up related to the depreciation-related excess deferred income taxes and investment tax credits included in this table and has a corresponding deferred tax asset disclosed in Note 2 - "Income Taxes."
(8) The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For depreciation-related timing differences under the normalized tax accounting method, this reduction will flow back to customers under the statutorily prescribed average rate assumption method.
(9) Idaho Power is collecting revenue in the Idaho jurisdiction for AFUDC on HCC 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.
(10) Mark-to-market assets and liabilities are discussed in Note 16 - "Fair Value Measurements."

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 mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms compare Idaho Power's actual net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs being recovered in Idaho Power's retail rates. Under the power cost adjustment mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and costs being recovered in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund. 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. The Idaho deferral period or PCA year runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

***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 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 sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three most recent 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, 2017 | $ 10.6 | The net increase in PCA rates included an offsetting $13.0 million reduction for the refund of previously collected Idaho energy efficiency rider funds. |
| June 1, 2016 | $ 17.3 | The net increase in PCA rates included the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of the October 2014 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds. |
| June 1, 2015 | $ (11.6) | The net decrease in PCA rates included the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of the December 2011 settlement stipulation, (b) a $1.5 million customer benefit relating to a change to the PCA methodology in 2015, and (c) $4.0 million of surplus Idaho energy efficiency rider funds. |

In March 2014, the IPUC issued an order approving Idaho Power's application 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 became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the PCA mechanism and instead results in collecting that portion through base rates.

***Oregon Jurisdiction Power Cost Adjustment Mechanism:*** Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual Oregon-jurisdictional return on equity (Oregon ROE) for the year is at least 100 basis points below Idaho Power's last authorized Oregon ROE. A refund to customers will occur only to the extent that Idaho Power's actual Oregon ROE for that year is at least 100 basis points above Idaho

Power's last authorized Oregon ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2017, 2016, and 2015 are summarized in the table that follows:

| Year and Mechanism | APCU or PCAM Adjustment |
|---|---|
| 2017 PCAM | Actual net power supply costs were within the deadband, resulting in no deferral. |
| 2017 APCU | A rate increase of $0.7 million annually took effect June 1, 2017. |
| 2016 PCAM | Actual net power supply costs were within the deadband, resulting in no deferral. |
| 2016 APCU | A rate increase of $0.2 million annually took effect June 1, 2016. |
| 2015 PCAM | Actual net power supply costs were within the deadband, resulting in no deferral. |
| 2015 APCU | A rate decrease of $0.7 million annually took effect June 1, 2015. |

**Notable Idaho Regulatory Matters**

***Idaho Base Rate Changes:*** Idaho base rates were most recently established in 2012, and adjusted in 2014. 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. In June 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 PCA rate that became effective June 1, 2014.

***October 2014 Idaho Settlement Stipulation:*** In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of a 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 accumulated deferred investment tax credits (ADITC) contemplated by the settlement stipulation has been amortized. The provisions of the October 2014 settlement stipulation are as follows:

- If Idaho Power's actual annual Idaho-jurisdiction return on year-end equity (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 PCA 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 PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension expense deferral regulatory asset (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.

In 2015, Idaho Power recorded a $3.2 million provision against current revenue for sharing with customers, as its Idaho ROE for 2015 was above 10.0 percent. In both 2016 and 2017, Idaho Power recorded no additional ADITC amortization and no provision for sharing with customers, as its Idaho ROE in both years was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2017, the full $45 million of additional ADITC remains available for future use under the terms 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 authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in 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) |
|---|---|---|
| 2016 | June 1, 2017-May 31, 2018 | $35.0 |
| 2015 | June 1, 2016-May 31, 2017 | $28.1 |
| 2014 | June 1, 2015-May 31, 2016 | $16.9 |

In July 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 (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA rates effective June 1, 2016.

***Hells Canyon Complex Relicensing Costs Settlement Stipulation:*** In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future rate case. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third party intervenor recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. The settlement stipulation is subject to review and approval by the IPUC. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017. For more information relating to HCC relicensing costs, see Note 12 - "Property, Plant and Equipment and Jointly-Owned Projects."

***Idaho Energy Efficiency Rider:*** On an annual basis, Idaho Power applies to the IPUC for an order designating Idaho Power's prior calendar year Idaho Energy Efficiency Rider (Idaho Rider) funded expenses as prudently incurred. In 2012 and 2013, the IPUC declined to decide the prudence of the increases in 2011 and 2012 Idaho Rider funded labor increases, while at the same time offering Idaho Power another opportunity to provide sufficient evidence at a future time. In 2017, Idaho Power applied to the IPUC for an order determining that the 2011 - 2016 Idaho Rider funded labor increases of $1.9 million were prudently incurred and eligible for collection through the Idaho Rider. On October 16, 2017, the IPUC issued its order determining that the 2011 - 2016 incremental Idaho Rider funded labor expenses of $1.9 million were prudently incurred. In its order, the IPUC also authorized actual Idaho Rider funded wage increases after 2016. The IPUC determined that this process does not require pre-determination as to prudence (up to a 2 percent annual cap), no longer requires labor to be examined in Idaho Power's annual prudence cases, and that the base wage level and annual cap will be reset in future general rate cases. The prudence order resulted in a $2.4 million increase in operating income in 2017.

**Tax Cuts and Jobs Act**

On December 22, 2017, the Tax Cut and Jobs Act was signed into law. On January 17, 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to 1) record a deferred regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in the federal income tax law and 2) to file a report with the IPUC by March 30, 2018, identifying and quantifying the income tax changes along with proposed tariff schedule changes. The IPUC order requires Idaho Power to estimate the income tax changes by comparing actual 2017 federal income tax expense components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full year of 2017. Idaho Power is currently working to comply with the IPUC order.

On December 29, 2017, Idaho Power filed an application with the OPUC, requesting authority to defer for later ratemaking treatment the Oregon jurisdictional earnings in excess of the currently authorized Oregon jurisdictional rate of return on equity that may result from the Tax Cuts and Jobs Act, as measured from the Company's annual Oregon Results of Operations. On December 29, 2017, OPUC Staff also filed an application with the OPUC requesting authority to defer for later ratemaking treatment the difference between Idaho Power's current retail rates and its current retail rates inclusive of the impact of the Tax Cuts and Jobs Act.

Idaho Power is working with the IPUC and OPUC to determine how potential income tax expense reductions from the changes in federal income tax law may benefit Idaho Power customers and affect IDACORP's and Idaho Power's financial condition and results of operations. The method through which potential cost savings may be accrued for the benefit of customers, including potential reductions to customer rates and to regulatory deferrals, will require approval from the IPUC and OPUC.

**Valmy Base Rate Adjustment Settlement Stipulations**

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for Idaho Power's jointly-owned North Valmy coal-fired power plant (Valmy Plant). The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017, in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted.

**Depreciation Rate Settlement Stipulations**

In May 2017, the IPUC and OPUC approved settlement stipulations related to revised depreciation rates for Idaho Power's electric plant in service other than the Valmy Plant, and adjusted base rates in Oregon to reflect the revised depreciation rates applied to electric plant-in-service based on balances from the most recent general rate case. These settlement stipulations provided for new depreciation rates to go into effect on June 1, 2017, with no significant resulting increase in revenue.

**Western Energy Imbalance Market Costs**

Idaho Power plans to participate in a new energy imbalance market implemented in the western United States (Western EIM). In August 2016, Idaho Power filed an application with the IPUC requesting specified regulatory accounting treatment associated with its participation in the Western EIM. In January 2017, the IPUC issued an order authorizing Idaho Power's requested deferral accounting treatment for costs associated with joining the Western EIM. Idaho Power can defer costs incurred until the earlier of when Idaho Power begins recovery of the costs and the deferral balance or the end of 2018. Idaho Power anticipates that its participation in the Western EIM will commence in April 2018.

In November 2017, Idaho Power filed an application with the IPUC requesting approval to establish an interim method of recovery for costs associated with participation in the Western EIM. If the IPUC approves the application as filed, Idaho Power intends to include $3.6 million in costs for recovery through the PCA, beginning June 1, 2018. Idaho Power has requested a decision from the IPUC by March 31, 2018.

**Notable Oregon Regulatory Matters**

***Oregon Base Rate Changes:*** Oregon base rates were most recently established in a general rate case in 2012. In February 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, in September 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**

Idaho Power uses 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, 2017 to September 30, 2018 | $ | 34.90 |
| October 1, 2016 to September 30, 2017 | $ | 25.52 |
| October 1, 2015 to September 30, 2016 | $ | 23.43 |
| October 1, 2014 to September 30, 2015 | $ | 22.48 |

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $130.4 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):

| | 2017 | 2016 |
|---|---|---|
| First mortgage bonds: | | |
| 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 |
| 6.00% 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 |
| 3.65% Series due 2045 | 250,000 | 250,000 |
| 4.05% Series due 2046 | 120,000 | 120,000 |
| Total first mortgage bonds | 1,575,000 | 1,575,000 |
| 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 | — | 1,064 |
| Unamortized issuance costs and discounts | (19,222) | (20,731) |
| Total IDACORP and Idaho Power outstanding debt(2) | 1,746,123 | 1,745,678 |
| Current maturities of long-term debt | — | (1,064) |
| Total long-term debt | $ 1,746,123 | $ 1,744,614 |

(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, 2017, to $1.741 billion.
(2) At December 31, 2017 and 2016, the overall effective cost rate of Idaho Power's outstanding debt was 4.87 percent.

At December 31, 2017, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

| 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|
| $ — | $ — | $ 230,000 | $ — | $ 75,000 | $ 1,460,345 |

### Long-Term Debt Issuances, Maturities, and Availability

On March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. On April 11, 2016, Idaho Power redeemed, prior to maturity, $100 million in principal amount of 6.15% first mortgage bonds, medium-term notes, Series H, due April 2019. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $14.0 million. Idaho Power used a portion of the net proceeds from the March 2016 sale of first mortgage bonds, medium-term notes to effect the redemption.

On March 6, 2015, Idaho Power issued $250.0 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120.0 million in principal amount of 6.025% first mortgage bonds, secured medium-term notes, Series H, due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million. Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April and May 2016, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (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. The order from the IPUC approved the issuance of the securities through May 31, 2019, subject to extensions 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 requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum all-in interest rate limit of 7.0 percent.

On May 20, 2016, IDACORP and Idaho Power filed a joint shelf registration statement with the U.S. Securities and Exchange Commission (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 September 27, 2016, Idaho Power entered into a selling agency agreement with seven 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 K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture. The Forty-eighth Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture. As of December 31, 2017, $500 million in principal amount of Series K Notes remained available for issuance under the Indenture.

***Mortgage*:** As of December 31, 2017, Idaho Power could issue under its Indenture approximately $1.8 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.

The Forty-eighth Supplemental Indenture increased the maximum amount of first mortgage bonds issuable by Idaho Power under the Indenture from $2.0 billion to $2.5 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

On November 6, 2015, IDACORP and Idaho Power entered into Credit Agreements replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide 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 $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 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, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 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, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent. 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 maturity date of November 6, 2020, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On November 7, 2017, IDACORP and Idaho Power executed the second extension agreement with the consent of all the lenders, extending the maturity date under both credit agreements to November 4, 2022. No other terms of the credit facilities, included the amount of permitted borrowing under the credit agreements, were affected by the extensions.

At December 31, 2017, no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2017, 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, 2017, and December 31, 2016:

| | IDACORP | | Idaho Power | | Total | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| **Commercial paper balances:** | | | | | | |
| At the end of year | $ — | $ — | $ — | $ 21,800 | $ — | $ 21,800 |
| Average during the year | $ 588 | $ 15,692 | $ 839 | $ 438 | $ 1,427 | $ 16,130 |
| **Weighted-average interest rate** | | | | | | |
| At the end of the year | —% | —% | —% | 1.13% | —% | 1.13% |

## 6. COMMON STOCK

### IDACORP Common Stock

The following table summarizes IDACORP common stock transactions during the last three years and shares reserved at December 31, 2017:

| | Shares issued | | | Shares reserved |
|---|---|---|---|---|
| | 2017 | 2016 | 2015 | December 31, 2017 |
| Balance at beginning of year | 50,420,017 | 50,352,051 | 50,308,702 | |
| Continuous equity program (inactive) | — | — | — | 3,000,000 |
| Dividend reinvestment and stock purchase plan | — | — | — | 2,576,723 |
| Employee savings plan | — | — | — | 3,567,954 |
| Long-term incentive and compensation plan(1) | — | 67,966 | 43,349 | 1,307,878 |
| Balance at end of year | 50,420,017 | 50,420,017 | 50,352,051 | |

(1) During 2017, IDACORP granted 72,397 restricted stock unit awards to employees and 12,050 shares of common stock to directors but made no original issuances of shares of common stock pursuant to the IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan.

In recent years, IDACORP has entered into sales agency agreements under which IDACORP could offer and sell shares of its common stock from time to time through an agent. The most recent sales agency agreement expired in May 2016, but IDACORP may choose to enter into a new sales agency agreement in the future. On May 20, 2016, IDACORP filed a shelf registration statement with the SEC, which became effective upon filing, for the potential offer and sale of an unspecified amount of shares of common stock.

### 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, 2017, the leverage ratios for IDACORP and Idaho Power were 44 percent and 46 percent, respectively. Based on these restrictions, IDACORP’s and Idaho Power’s dividends were limited to $1.3 billion and $1.1 billion, respectively, at December 31, 2017. 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, 2017, 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, 2017, Idaho Power's common equity capital was 54 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 (FPA) prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the FPA 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. SHARE-BASED COMPENSATION

IDACORP has one share-based compensation plan -- the 2000 Long-Term Incentive and Compensation Plan (LTICP). The 1994 Restricted Stock Plan was terminated effective February 9, 2017. The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock and restricted stock units (together, Restricted Stock), performance shares and performance-based units (together, Performance-Based Shares), and several other types of share-based awards. At December 31, 2017, the maximum number of shares available under the LTICP was 836,220.

***Restricted Stock and Performance-Based Shares Awards***

Restricted Stock awards have three-year vesting periods and entitle the recipients to dividends or dividend equivalents, as applicable, and voting rights, except that holders of restricted stock units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 Shares awards have three-year vesting periods and entitle the recipients to voting rights, except that holders of performance-based units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 and the year issued, the final number of shares awarded can range from zero to 200 percent of the target award. Dividends or dividend equivalents, as applicable, 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-Based Shares award 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/Units | Weighted-Average Grant Date Fair Value | Number of Shares/Units | Weighted-Average Grant Date Fair Value |
| Nonvested shares/units at January 1, 2017 | 201,065 | $ 61.49 | 199,526 | $ 61.51 |
| Shares/units granted | 96,191 | 75.37 | 95,568 | 75.40 |
| Shares/units forfeited | (6,179) | 75.54 | (6,179) | 75.54 |
| Shares/units vested | (89,999) | 51.06 | (89,263) | 51.07 |
| Nonvested shares/units at December 31, 2017 | 201,078 | $ 72.37 | 199,652 | $ 72.39 |

The total fair value of shares vested was $7.5 million in 2017 and $8.3 million in both 2016 and 2015. At December 31, 2017, IDACORP had $5.5 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 $5.4 million. These costs are expected to be recognized over a weighted-average period of 1.7 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2017, a total of 12,050 shares were awarded to directors at a grant date fair value of $82.93 per share. Directors elected to defer receipt of 3,012 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

***Compensation Expense:*** The following table shows the compensation cost recognized in income and the tax benefits resulting from the LTICP, 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 | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| Compensation cost | $ 7,384 | $ 5,561 | $ 5,299 | $ 7,304 | $ 5,494 | $ 5,221 |
| Income tax benefit | 2,887 | 2,174 | 2,072 | 2,856 | 2,148 | 2,042 |

No equity compensation costs have been capitalized. These costs are primarily reported within other operations and maintenance expense in the consolidated statements of income.

## 8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share for the years ended December 31, 2017, 2016, and 2015 (in thousands, except for per share amounts):

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| Numerator: | | | |
| Net income attributable to IDACORP, Inc. | $ 212,419 | $ 198,288 | $ 194,679 |
| Denominator: | | | |
| Weighted-average common shares outstanding - basic | 50,361 | 50,298 | 50,220 |
| Effect of dilutive securities | 63 | 75 | 72 |
| Weighted-average common shares outstanding - diluted | 50,424 | 50,373 | 50,292 |
| Basic earnings per share | $ 4.22 | $ 3.94 | $ 3.88 |
| Diluted earnings per share | $ 4.21 | $ 3.94 | $ 3.87 |

## 9. COMMITMENTS

### Purchase Obligations

At December 31, 2017, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Cogeneration and power production | $ 234,094 | $ 229,129 | $ 230,734 | $ 236,644 | $ 242,380 | $2,951,425 |
| Fuel | 42,772 | 29,450 | 27,671 | 27,861 | 8,389 | 92,588 |

As of December 31, 2017, Idaho Power had 1,114 MW nameplate capacity of PURPA-related projects on-line, with an additional 5 MW nameplate capacity of projects projected to be on-line in 2018 and an additional 24 MW expected to be added in 2019. 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 $170 million in 2017, $154 million in 2016, and $131 million in 2015.

Idaho Power also has the following long-term commitments (in thousands of dollars):

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter |
|---|---|---|---|---|---|---|
| Operating leases(1) | $ 3,529 | $ 4,434 | $ 4,538 | $ 4,500 | $ 4,507 | $ 30,052 |
| Equipment, maintenance, and service agreements(1) | 35,867 | 10,378 | 11,828 | 6,421 | 10,322 | 53,572 |
| FERC and other industry-related fees(1) | 12,940 | 12,836 | 10,145 | 10,145 | 10,145 | 50,729 |

(1) Approximately $34 million, $20 million, and $60 million of the obligations included in operating leases; equipment, maintenance, and service agreements; and FERC and other industry-related fees, respectively, have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

IDACORP’s expense for operating leases was $5.6 million in 2017, $4.9 million in 2016, and $4.4 million in 2015.

**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 $56.7 million at December 31, 2017, representing IERCo's one-third share of BCC's total reclamation obligation of $170.1 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2017, the value of the reclamation trust fund was $103.4 million. During 2017, the reclamation trust fund made no distributions 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, and does, add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. 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, 2017, 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, some of which 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. 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, although there is no assurance that such recovery would be granted.

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, record 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 and recently issued executive orders related to environmental matters 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.

## 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 two nonqualified defined benefit pension plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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 2017, 2016, and 2015 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 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| **Change in projected benefit obligation:** | | | | |
| Benefit obligation at January 1 | $ 895,060 | $ 835,523 | $ 99,570 | $ 95,389 |
| Service cost | 33,742 | 32,019 | 759 | 1,228 |
| Interest cost | 38,957 | 37,813 | 4,315 | 4,275 |
| Actuarial loss | 67,758 | 22,640 | 10,635 | 2,933 |
| Plan amendment | — | 81 | — | 120 |
| Benefits paid | (36,173) | (33,016) | (4,976) | (4,375) |
| Projected benefit obligation at December 31 | 999,344 | 895,060 | 110,303 | 99,570 |
| **Change in plan assets:** | | | | |
| Fair value at January 1 | 607,568 | 559,616 | — | — |
| Actual return on plan assets | 86,288 | 40,968 | — | — |
| Employer contributions | 40,000 | 40,000 | — | — |
| Benefits paid | (36,173) | (33,016) | — | — |
| Fair value at December 31 | 697,683 | 607,568 | — | — |
| Funded status at end of year | $ (301,661) | $ (287,492) | $ (110,303) | $ (99,570) |
| **Amounts recognized in the statement of financial position consist of:** | | | | |
| Other current liabilities | $ — | $ — | $ (5,010) | $ (4,733) |
| Noncurrent liabilities | (301,661) | (287,492) | (105,293) | (94,837) |
| Net amount recognized | $ (301,661) | $ (287,492) | $ (110,303) | $ (99,570) |
| **Amounts recognized in accumulated other comprehensive income consist of:** | | | | |
| Net loss | $ 277,052 | $ 263,634 | $ 41,333 | $ 33,660 |
| Prior service cost | 68 | 96 | 498 | 625 |
| Subtotal | 277,120 | 263,730 | 41,831 | 34,285 |
| Less amount recorded as regulatory asset | (277,120) | (263,730) | — | — |
| Net amount recognized in accumulated other comprehensive income | $ — | $ — | $ 41,831 | $ 34,285 |
| **Accumulated benefit obligation** | $ 850,763 | $ 766,367 | $ 100,222 | $ 91,146 |

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 recorded value of these investments was approximately $85.7 million and $77.8 million at December 31, 2017 and 2016, 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 | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| Service cost | $ 33,742 | $ 32,019 | $ 33,164 | $ 759 | $ 1,228 | $ 1,689 |
| Interest cost | 38,957 | 37,813 | 35,171 | 4,315 | 4,275 | 3,868 |
| Expected return on assets | (45,138) | (42,081) | (42,310) | — | — | — |
| Amortization of net loss | 13,190 | 13,331 | 13,927 | 2,963 | 3,532 | 4,195 |
| Amortization of prior service cost | 28 | 59 | 221 | 127 | 168 | 185 |
| Net periodic pension cost | 40,779 | 41,141 | 40,173 | 8,164 | 9,203 | 9,937 |
| Regulatory deferral of net periodic benefit cost[(1)] | (38,699) | (39,335) | (38,327) | — | — | — |
| Previously deferred pension cost recognized[(1)] | 17,154 | 17,154 | 17,154 | — | — | — |
| Net periodic benefit cost recognized for financial reporting[(1)] | $ 19,234 | $ 18,960 | $ 19,000 | $ 8,164 | $ 9,203 | $ 9,937 |

(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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those 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 | | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| Actuarial (loss) gain during the year | $ (26,608) | $ (23,753) | $ (3,790) | $ (10,635) | $ (2,933) | $ 353 |
| Plan amendment service cost | — | (81) | — | — | (120) | — |
| Reclassification adjustments for: | | | | | | |
| Amortization of net loss | 13,190 | 13,331 | 13,927 | 2,963 | 3,532 | 4,195 |
| Amortization of prior service cost | 28 | 59 | 221 | 127 | 168 | 185 |
| Adjustment for deferred tax effects | 1,744 | 4,083 | (4,050) | 1,555 | (253) | (1,851) |
| Adjustment due to the effects of regulation | 11,646 | 6,361 | (6,308) | — | — | — |
| Other comprehensive income recognized related to pension benefit plans | $ — | $ — | $ — | $ (5,990) | $ 394 | $ 2,882 |

In 2018, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $17.5 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2017, relating to the pension plan and SMSP. This amount consists of $13.6 million of amortization of net loss for the pension plan and $3.8 million of amortization of net loss and $0.1 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):

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023-2027 |
|---|---|---|---|---|---|---|
| Pension Plan | $ 35,312 | $ 37,490 | $ 39,983 | $ 42,438 | $ 44,797 | $ 257,290 |
| SMSP | 5,100 | 5,161 | 5,538 | 5,707 | 5,880 | 30,962 |

As of December 31, 2017, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2018. Depending on market conditions and cash flow considerations in 2018, Idaho Power could contribute up to $40 million to the pension plan during 2018 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

**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):

| | 2017 | 2016 |
|---|---|---|
| **Change in accumulated benefit obligation:** | | |
| Benefit obligation at January 1 | $ 63,876 | $ 62,393 |
| Service cost | 973 | 1,116 |
| Interest cost | 2,783 | 2,766 |
| Actuarial loss | 5,769 | 1,550 |
| Benefits paid[(1)] | (3,562) | (3,949) |
| Plan amendments | 212 | — |
| Benefit obligation at December 31 | 70,051 | 63,876 |
| **Change in plan assets:** | | |
| Fair value of plan assets at January 1 | 34,999 | 35,566 |
| Actual return on plan assets | 5,112 | 2,425 |
| Employer contributions[(1)] | 1,745 | 957 |
| Benefits paid[(1)] | (3,562) | (3,949) |
| Fair value of plan assets at December 31 | 38,294 | 34,999 |
| Funded status at end of year (included in noncurrent liabilities) | $ (31,757) | $ (28,877) |

[(1)] Contributions and benefits paid are each net of $3.4 million and $3.7 million of plan participant contributions for 2017 and 2016, respectively.

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

| | 2017 | 2016 |
|---|---|---|
| Net gain | $ 2,777 | $ (55) |
| Prior service cost | 269 | 104 |
| Subtotal | 3,046 | 49 |
| Less amount recognized in regulatory assets | (3,046) | (49) |
| Net amount recognized in accumulated other comprehensive income | $ — | $ — |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost | $ 973 | $ 1,116 | $ 1,235 |
| Interest cost | 2,783 | 2,766 | 2,678 |
| Expected return on plan assets | (2,307) | (2,474) | (2,680) |
| Amortization of prior service cost | 47 | 26 | 15 |
| Net periodic postretirement benefit cost | $ 1,496 | $ 1,434 | $ 1,248 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Actuarial (loss) gain during the year | $ (2,964) | $ (1,600) | $ 2,413 |
| Prior service cost arising during the year | (212) | — | — |
| Reclassification adjustments for amortization of prior service cost | 47 | 26 | 15 |
| Adjustment for deferred tax effects | 807 | 615 | (949) |
| Adjustment due to the effects of regulation | 2,322 | 959 | (1,479) |
| Other comprehensive income related to postretirement benefit plans | $ — | $ — | $ — |

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

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023-2027 |
|---|---|---|---|---|---|---|
| Expected benefit payments | $ 5,051 | $ 4,667 | $ 4,374 | $ 4,080 | $ 4,070 | $ 19,910 |

**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 | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| Discount rate | 3.95% | 4.45% | 3.95% | 4.45% | 3.95% | 4.45% |
| Rate of compensation increase(1) | 4.17% | 4.11% | 4.75% | 4.75% | — | — |
| Medical trend rate | — | — | — | — | 6.8% | 8.3% |
| Dental trend rate | — | — | — | — | 4.1% | 5.0% |
| Measurement date | 12/31/2017 | 12/31/2016 | 12/31/2017 | 12/31/2016 | 12/31/2017 | 12/31/2016 |

(1) The 2017 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.67% 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 | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| Discount rate | 4.45% | 4.60% | 4.25% | 4.45% | 4.60% | 4.20% | 4.45% | 4.60% | 4.20% |
| Expected long-term rate of return on assets | 7.50% | 7.50% | 7.50% | — | — | — | 6.75% | 7.25% | 7.25% |
| Rate of compensation increase | 4.17% | 4.11% | 4.11% | 4.75% | 4.50% | 4.50% | — | —% | —% |
| Medical trend rate | — | — | — | — | — | — | 6.8% | 8.30% | 9.70% |
| Dental trend rate | — | — | — | — | — | — | 4.0% | 5.00% | 5.00% |

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.8 percent in 2017 and is assumed to decrease to 6.4 percent in 2018, 5.9 percent in 2019, 5.4 percent in 2020 and to gradually decrease to 4.1 percent by 2074. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 4.0 percent, or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2017 (in thousands of dollars):

| | One-Percentage-Point | |
|---|---|---|
| | Increase | Decrease |
| Effect on total of cost components | $ 301 | $ (223) |
| Effect on accumulated postretirement benefit obligation | 3,166 | (2,459) |

**Plan Assets**

***Pension Asset Allocation Policy:*** The target allocation and actual allocations at December 31, 2017, for the pension asset portfolio by asset class is set forth below:

| Asset Class | Target Allocation | Actual Allocation December 31, 2017 |
|---|---|---|
| Debt securities | 24% | 24% |
| Equity securities | 56% | 58% |
| Real estate | 7% | 6% |
| Other plan assets | 13% | 12% |
| 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, 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 - "Derivative Financial Instruments." The following table presents the fair value of the plans' investments by asset category (in thousands of dollars).

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets at December 31, 2017** | | | | |
| Cash and cash equivalents | $ 20,852 | $ — | $ — | $ 20,852 |
| Short-term bonds | 20,475 | — | — | 20,475 |
| Intermediate bonds | 20,699 | 82,923 | — | 103,622 |
| Long-term bonds | — | 40,707 | — | 40,707 |
| Equity Securities: Large-Cap | 95,179 | — | — | 95,179 |
| Equity Securities: Mid-Cap | 81,127 | — | — | 81,127 |
| Equity Securities: Small-Cap | 62,502 | — | — | 62,502 |
| Equity Securities: Micro-Cap | 32,753 | — | — | 32,753 |
| Equity Securities: International | 6,774 | — | — | 6,774 |
| Equity Securities: Emerging Markets | 8,785 | — | — | 8,785 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Equity Securities: International | | | | 83,589 |
| Equity Securities: Emerging Markets | | | | 36,255 |
| Real estate | | | | 38,435 |
| Private market investments | | | | 31,618 |
| Commodities fund | | | | 35,010 |
| **Total** | $ 349,146 | $ 123,630 | $ — | $ 697,683 |
| Postretirement plan assets(1) | $ 567 | $ 37,727 | $ — | $ 38,294 |

| | Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets at December 31, 2016** | | | | |
| Cash and cash equivalents | $ 28,632 | $ — | $ — | $ 28,632 |
| Short-term bonds | 11,198 | — | — | 11,198 |
| Intermediate bonds | 11,904 | 88,734 | — | 100,638 |
| Long-term bonds | — | 20,573 | — | 20,573 |
| Equity Securities: Large-Cap | 80,582 | — | — | 80,582 |
| Equity Securities: Mid-Cap | 68,634 | — | — | 68,634 |
| Equity Securities: Small-Cap | 53,766 | — | — | 53,766 |
| Equity Securities: Micro-Cap | 29,671 | — | — | 29,671 |
| Equity Securities: International | 7,782 | — | — | 7,782 |
| Equity Securities: Emerging Markets | 9,204 | — | — | 9,204 |
| **Plan assets measured at NAV (not subject to hierarchy disclosure)** | | | | |
| Equity Securities: International | | | | 64,930 |
| Equity Securities: Emerging Markets | | | | 24,443 |
| Real estate | | | | 41,907 |
| Private market investments | | | | 33,713 |
| Commodities fund | | | | 31,895 |
| **Total** | $ 301,373 | $ 109,307 | $ — | $ 607,568 |
| Postretirement plan assets(1) | $ 28 | $ 34,971 | $ — | $ 34,999 |

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

For the year ended December 31, 2017 and December 31, 2016, there were no material transfers into or out of Levels 1, 2, or 3.

***Fair Value Measurement of Level 2 Plan assets and Plan assets measured at NAV:***

Level 2 Bonds: These investments represent U.S. government, agency bonds, and corporate bonds. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing market prices for similar assets or liabilities in active markets.

Level 2 Postretirement Asset: This asset represents an investment in a life insurance contract and is 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.

Commingled Funds: These funds, made up of the international, emerging markets equity securities, and commodities fund measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The value of the commingled funds are presented at estimated fair value, which is determined based on the unit value of the fund. The values of these investments are calculated by the custodian for the fund company on a monthly or more frequent basis, and are based on market prices of the assets held by each of the commingled funds divided by the number of fund shares outstanding for the respective fund. The investments in commingled funds have redemption limitations that permit monthly redemption following notice requirements of 5 to 7 days.

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 companies, 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. Redemptions are generally available on a quarterly basis, with 10 to 35 days written notice, depending on the individual fund. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV or the fund’s estimate of fair value at the end of the quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. To protect other fund holders, real estate funds have no duty to liquidate or encumber funds to meet redemption requests.

Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund companies based on the estimated fair values of the underlying fund holdings divided by the fund shares outstanding or multiplied by the ownership percentages of the holder. 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. Redemptions are available on a quarterly basis with 70 days written notice. Redemptions will be processed at the quarterly NAV or fair value within 60 days following quarter end. In the event of a full redemption, a reserve amount of 5% to 10% of the redemption amount may be held in reserve until the audited financial statements of the fund are published. This allows the fund to adjust the redemption so that other fund holders are not adversely impacted. Venture capital fund investments are valued by the fund companies 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. These funds are formed for a stated life of 10 to 15 years. The general partner can extend the fund life for 2 or 3 one-year periods. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

**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 $7.4 million , $7.5 million, and $6.9 million in 2017, 2016, and 2015, respectively.

**Post-employment Benefits**

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power’s disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefits included in other deferred credits on both IDACORP’s and Idaho Power’s consolidated balance sheets at December 31, 2017, 2016, and 2015, were approximately $2 million.

**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 ended December 31, 2017 and 2016 (in thousands of dollars):

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | **Balance** | **Avg Rate** | **Balance** | **Avg Rate** |
| Production | $ 2,598,940 | 3.07% | $ 2,551,823 | 2.40% |
| Transmission | 1,163,240 | 1.94% | 1,120,903 | 2.02% |
| Distribution | 1,710,126 | 2.44% | 1,637,131 | 2.72% |
| General and Other | 433,856 | 6.01% | 422,187 | 5.49% |
| Total in service | 5,906,162 | 2.87% | 5,732,044 | 2.64% |
| Accumulated provision for depreciation | (2,098,274) | | (1,988,477) | |
| In service - net | $ 3,807,888 | | $ 3,743,567 | |

At December 31, 2017, Idaho Power's construction work in progress balance of $452.4 million included relicensing costs of $268.7 million for the HCC, Idaho Power's largest hydroelectric complex. In 2017, 2016, and 2015, the IPUC authorized Idaho Power to include in its Idaho jurisdiction rates $6.5 million annually ($10.7 million when grossed-up for the effect of income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2017, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $119.7 million.

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, 2017 (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 | $ 722,440 | $ 6,935 | $ 316,092 | 33 | 771 |
| Boardman | Boardman, OR | 82,193 | 55 | 71,250 | 10 | 64 |
| Valmy Units 1 and 2 | Winnemucca, NV | 409,836 | 359 | 235,670 | 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 $86.4 million in 2017, $92.9 million in 2016, and $92.8 million in 2015.

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 $9.8 million in 2017, $7.8 million in 2016, and $8.1 million in 2015.

IDACORP's consolidated VIE, Marysville, owns a hydroelectric plant with a net book value of $15.7 million and $16.2 million at December 31, 2017 and 2016, respectively.

## 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.

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 - "Regulatory Matters" for the removal costs recorded as regulatory liabilities on IDACORP's and Idaho Power's consolidated balance sheets as of December 31, 2017 and 2016.

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

| | 2017 | 2016 |
|---|---|---|
| Balance at beginning of year | $ 26,257 | $ 26,153 |
| Accretion expense | 1,015 | 1,031 |
| Revisions in estimated cash flows | (791) | 1,759 |
| Liability settled | (66) | (2,686) |
| Balance at end of year | $ 26,415 | $ 26,257 |

## 14. INVESTMENTS

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

| | 2017 | 2016 |
|---|---|---|
| Idaho Power investments: | | |
| Bridger Coal Company (equity method investment) | $ 68,566 | $ 82,299 |
| Exchange traded short-term bond funds and cash equivalents | 30,249 | 23,908 |
| Executive deferred compensation plan investments | 17 | 111 |
| Total Idaho Power investments | 98,832 | 106,318 |
| Investments in affordable housing (IDACORP Financial Services) | 5,521 | 7,643 |
| Ida-West joint ventures (equity method investments) | 11,345 | 11,213 |
| Total IDACORP investments | $ 115,698 | $ 125,174 |

### 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 of unconsolidated equity-method investments (in thousands of dollars):

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Bridger Coal Company (Idaho Power) | $ 9,267 | $ 10,855 | $ 9,773 |
| Ida-West joint ventures | 2,107 | 2,016 | 1,355 |
| Total | $ 11,374 | $ 12,871 | $ 11,128 |

### 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, 2017 and December 31, 2016. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Proceeds from sales | $ 4,989 | $ 15,693 | $ 34,243 |
| Gross realized gains from sales | — | 54 | — |

### 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. IDACORP accounts for its equity-method investments in qualified affordable housing projects using the proportional amortization method and recognizes the net investment performance in the consolidated statements of income as a component of income tax expense.

## 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, 2017, 2016, and 2015 (in thousands of dollars):

| | Location of Realized Gain/(Loss) on Derivatives Recognized in Income | Gain/(Loss) on Derivatives Recognized in Income[1] | | |
|---|---|---|---|---|
| | | 2017 | 2016 | 2015 |
| Financial swaps | Off-system sales | $ 902 | $ 1,405 | $ 2,882 |
| Financial swaps | Purchased power | 166 | 586 | 748 |
| Financial swaps | Fuel expense | 701 | (1,947) | (6,045) |
| Financial swaps | Other operations and maintenance | (84) | (161) | (50) |
| Forward contracts | Off-system sales | 55 | (54) | — |
| Forward contracts | Purchased power | (69) | 86 | (6) |
| Forward contracts | Fuel expense | 4 | 139 | 54 |

(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 - "Fair Value Measurements" 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, 2017 and 2016 (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, 2017** | | | | | | | |
| Current: | | | | | | | |
| Financial swaps | Other current assets | $ 18 | $ — | $ 18 | $ — | $ — | $ — |
| Financial swaps | Other current liabilities | 553 | (553) | — | 1,971 | (748) [1] | 1,223 |
| Forward contracts | Other current liabilities | — | — | — | 2 | — | 2 |
| Long-term: | | | | | | | |
| Financial swaps | Other assets | 4 | — | 4 | — | — | — |
| Total | | $ 575 | $ (553) | $ 22 | $ 1,973 | $ (748) | $ 1,225 |
| **December 31, 2016** | | | | | | | |
| Current: | | | | | | | |
| Financial swaps | Other current assets | $ 8,134 | $ (2,183) [2] | $ 5,951 | $ 302 | $ (302) | $ — |
| Total | | $ 8,134 | $ (2,183) | $ 5,951 | $ 302 | $ (302) | $ — |

(1) Current liability derivative amounts offset include $0.2 million of collateral receivable for the period ending December 31, 2017.

(2) Current asset derivative amounts offset include $1.9 million of collateral payable for the period ending December 31, 2016.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2017 and 2016 (in thousands of units):

| | | December 31, | |
|---|---|---|---|
| **Commodity** | **Units** | **2017** | **2016** |
| Electricity purchases | MWh | 312 | 217 |
| Electricity sales | MWh | 224 | 135 |
| Natural gas purchases | MMBtu | 7,028 | 6,604 |
| Natural gas sales | MMBtu | 140 | 70 |
| Diesel purchases | Gallons | — | 1,188 |

**Credit Risk**

At December 31, 2017, 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, 2017, was $2.0 million. Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2017, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $4.5 million to cover open liability positions as well as completed transactions that have not yet been paid.

## 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 have 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, 2017 and 2016.

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, 2017 and 2016 (in thousands of dollars):

| | December 31, 2017 | | | | December 31, 2016 | | | |
|---|---|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| **Assets:** | | | | | | | | |
| Money market funds | | | | | | | | |
| IDACORP | $ 28,038 | $ — | $ — | $ 28,038 | $ 15,000 | $ — | $ — | $ 15,000 |
| Idaho Power | 10,260 | — | — | 10,260 | 29,967 | — | — | 29,967 |
| Derivatives | 22 | — | — | 22 | 5,951 | — | — | 5,951 |
| Trading securities: Equity securities | 17 | — | — | 17 | 111 | — | — | 111 |
| Available-for-sale securities: Equity securities | 30,249 | — | — | 30,249 | 23,908 | — | — | 23,908 |
| **Liabilities:** | | | | | | | | |
| Derivatives | $ 1,223 | $ 2 | $ — | $ 1,225 | $ — | $ — | $ — | $ — |

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, are held in a Rabbi trust, and are actively traded money market and exchange-traded 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, 2017 and 2016, using available market information and appropriate valuation methodologies (in thousands of dollars):

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| | (thousands of dollars) | | | |
| **IDACORP** | | | | |
| **Assets:** | | | | |
| Notes receivable[(1)] | $ 3,804 | $ 3,804 | $ 3,804 | $ 3,804 |
| **Liabilities:** | | | | |
| Long-term debt[(1)] | 1,746,123 | 1,915,459 | 1,745,678 | 1,858,666 |
| **Idaho Power** | | | | |
| **Liabilities:** | | | | |
| Long-term debt[(1)] | $ 1,746,123 | $ 1,915,459 | $ 1,745,678 | $ 1,858,666 |

[(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 - "Fair Value Measurements."

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 one-third 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 IDACORP Energy Services Co., 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 |
|---|---|---|---|---|
| **2017** | | | | |
| Revenues | $ 1,344,893 | $ 4,593 | $ — | $ 1,349,486 |
| Operating income | 302,408 | 1,943 | — | 304,351 |
| Other income | 23,550 | 191 | — | 23,741 |
| Interest income | 6,044 | 295 | (211) | 6,128 |
| Equity-method income | 9,267 | 2,107 | — | 11,374 |
| Interest expense | 83,660 | 297 | (211) | 83,746 |
| Income before income taxes | 257,609 | 4,239 | — | 261,848 |
| Income tax expense (benefit) | 51,262 | (2,602) | — | 48,660 |
| Income attributable to IDACORP, Inc. | 206,347 | 6,072 | — | 212,419 |
| Total assets | 5,995,435 | 143,696 | (93,726) | 6,045,405 |
| Expenditures for long-lived assets | 285,471 | 17 | — | 285,488 |

| | | | | |
|---|---|---|---|---|
| **2016** | | | | |
| Revenues | $ 1,259,353 | $ 2,667 | $ — | $ 1,262,020 |
| Operating income | 265,491 | 6,285 | — | 271,776 |
| Other income | 27,658 | 6 | — | 27,664 |
| Interest income | 4,235 | 127 | (121) | 4,241 |
| Equity-method income | 10,855 | 2,016 | — | 12,871 |
| Interest expense | 81,812 | 344 | (121) | 82,035 |
| Income before income taxes | 226,427 | 8,090 | — | 234,517 |
| Income tax expense (benefit) | 37,185 | (756) | — | 36,429 |
| Income attributable to IDACORP, Inc. | 189,242 | 9,046 | — | 198,288 |
| Total assets | 6,236,744 | 73,137 | (19,984) | 6,289,897 |
| Expenditures for long-lived assets | 296,948 | 2 | — | 296,950 |
| **2015** | | | | |
| Revenues | $ 1,267,505 | $ 2,784 | $ — | $ 1,270,289 |
| Operating income | 282,252 | (155) | — | 282,097 |
| Other income | 25,868 | 37 | — | 25,905 |
| Interest income | 3,037 | 64 | (62) | 3,039 |
| Equity-method income | 9,773 | 1,355 | — | 11,128 |
| Interest expense | 81,718 | 278 | (62) | 81,934 |
| Income before income taxes | 239,211 | 1,024 | — | 240,235 |
| Income tax expense (benefit) | 48,228 | (2,468) | — | 45,760 |
| Income attributable to IDACORP, Inc. | 190,983 | 3,696 | — | 194,679 |
| Total assets | 5,968,835 | 71,704 | (17,225) | 6,023,314 |
| Expenditures for long-lived assets | 293,969 | 52 | — | 294,021 |

## 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** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Interest and dividend income, net | $ 3,872 | $ 4,466 | $ 2,890 |
| Carrying charges on regulatory assets | 2,310 | 2,082 | 1,774 |
| Other income | 833 | 767 | 777 |
| Income from life insurance investments | 2,090 | 2,588 | 1,739 |
| Other expense | (20) | (29) | (21) |
| **Total** | $ 9,085 | $ 9,874 | $ 7,159 |
| **Idaho Power - Other expense, net** | | | |
| Interest and dividend income, net | $ 3,787 | $ 4,460 | $ 2,889 |
| Carrying charges on regulatory assets | 2,310 | 2,082 | 1,774 |
| Other income | 644 | 761 | 739 |
| SMSP expense | (8,164) | (9,203) | (9,937) |
| Income from life insurance investments | 2,090 | 2,588 | 1,739 |
| Other expense | (2,393) | (2,632) | (2,275) |
| **Total** | $ (1,726) | $ (1,944) | $ (5,071) |

## 19. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income 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, 2017, 2016, and 2015 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

| | **Year Ended December 31,** | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| Defined benefit pension items | | | |
| Balance at beginning of period | $ (20,882) | $ (21,276) | $ (24,158) |
| Other comprehensive income before reclassifications | (7,872) | (1,859) | 214 |
| Amounts reclassified out of AOCI to net income | 1,882 | 2,253 | 2,668 |
| Net current-period other comprehensive income | (5,990) | 394 | 2,882 |
| Cumulative effect of change in accounting principle[1] | (4,092) | — | — |
| Balance at end of period | $ (30,964) | $ (20,882) | $ (21,276) |

[1]The cumulative effect of change in accounting principle relates to the adoption of ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income.* See Note 1 - "Summary of Significant Accounting Policies" for more information.

The table below presents the effects on net income of amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2017, 2016, and 2015 (in thousands of dollars). Items in parentheses indicate increases to net income.

| | Amount Reclassified from AOCI<br>Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| Amortization of defined benefit pension items[1] | | | |
| Prior service cost | $ 127 | $ 168 | $ 185 |
| Net loss | 2,963 | 3,532 | 4,195 |
| Total before tax | 3,090 | 3,700 | 4,380 |
| Tax benefit[2] | (1,208) | (1,447) | (1,712) |
| Net of tax | 1,882 | 2,253 | 2,668 |
| Total reclassification for the period | $ 1,882 | $ 2,253 | $ 2,668 |

[1] 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.
[2] The tax benefit is included in income tax expense in the consolidated income statements of both IDACORP and Idaho Power.

## 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 $0.7 million in 2017, $0.8 million in 2016, and $0.9 million in 2015.

At December 31, 2017 and 2016, Idaho Power had a $57.3 million and $0.9 million payable to IDACORP, respectively, which was included in its accounts payable to affiliates balance on its consolidated balance sheets.

***Ida-West:*** Idaho Power purchases all of the power generated by four of Ida-West’s hydroelectric projects located in Idaho. Idaho Power paid Ida-West $9.8 million in 2017, $7.8 million in 2016 and $8.1 million in 2015.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of IDACORP, Inc.

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, 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, 2017, and the related notes and the schedules listed in the Index at Item 8 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, 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 22, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho

February 22, 2018

We have served as the Company's auditor since 1932.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Idaho Power Company

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the “Company”) as of December 31, 2017 and 2016, 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, 2017, and the related notes and the schedule listed in the Index at Item 8 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2017, 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 22, 2018, expressed an unqualified opinion on the Company’s internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error of fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho

February 22, 2018

We have served as the Company's auditor since 1932.

**SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED**

**QUARTERLY FINANCIAL DATA**

The following unaudited information is presented for each quarter of 2017 and 2016 (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.** | | | | |
| **2017** | | | | |
| Revenues | $ 302,544 | $ 333,006 | $ 408,324 | $ 305,612 |
| Operating income | 50,815 | 79,110 | 120,914 | 53,512 |
| Net income | 33,006 | 50,096 | 91,076 | 39,010 |
| Net income attributable to IDACORP, Inc. | 33,102 | 49,831 | 90,634 | 38,852 |
| Basic earnings per share | $ 0.66 | $ 0.99 | $ 1.80 | $ 0.77 |
| Diluted earnings per share | $ 0.66 | $ 0.99 | $ 1.80 | $ 0.77 |
| **2016** | | | | |
| Revenues | $ 280,956 | $ 315,436 | $ 372,045 | $ 293,583 |
| Operating income | 43,818 | 76,953 | 97,928 | 53,077 |
| Net income | 25,530 | 56,386 | 83,017 | 33,155 |
| Net income attributable to IDACORP, Inc. | 25,729 | 56,246 | 83,100 | 33,213 |
| Basic earnings per share | $ 0.51 | $ 1.12 | $ 1.65 | $ 0.66 |
| Diluted earnings per share | $ 0.51 | $ 1.12 | $ 1.65 | $ 0.66 |
| | | | | |
| **Idaho Power Company** | | | | |
| **2017** | | | | |
| Revenues | $ 301,964 | $ 331,768 | $ 406,655 | $ 304,506 |
| Income from operations | 53,579 | 81,021 | 122,541 | 55,803 |
| Net income | 32,482 | 48,381 | 88,329 | 37,155 |
| **2016** | | | | |
| Revenues | $ 280,566 | $ 314,411 | $ 371,474 | $ 292,902 |
| Income from operations | 47,124 | 79,409 | 100,928 | 49,836 |
| Net income | 25,534 | 54,807 | 80,029 | 28,872 |

## 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, 2017, 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, 2017. 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, 2017, 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, 2017 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, 2017.

February 22, 2018

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of IDACORP, Inc.

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2017 of the Company and our report dated February 22, 2018 expressed an unqualified opinion on those financial statements and financial statement schedules.

**Basis for Opinion**

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, 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.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho

February 22, 2018

**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, 2017, 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, 2017. 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, 2017, 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, 2017 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, 2017.

February 22, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the shareholder and Board of Directors of Idaho Power Company

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2017 of the Company and our report dated February 22, 2018 expressed an unqualified opinion on those financial statements and financial statement schedule.

**Basis for Opinion**

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, 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.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho

February 22, 2018

**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, 2017 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 at IDACORP - Codes of Business Conduct," and "Corporate Governance at IDACORP - Certain Relationships and Related Transactions" to be filed pursuant to Regulation 14A for the 2018 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 2018 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 2018 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2017, with respect to the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP) pursuant to which equity securities of IDACORP may be issued.

**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 | 69,241 (1) | $ — (2) | 836,220 (3) |
| Equity compensation plans not approved by shareholders | — | $ — | — |
| Total | 69,241 | $ — | 836,220 |

(1) Represents shares subject to outstanding time-based restricted stock units and performance-based units (at target).

(2) Time-based restricted stock units and performance-based units have no exercise price.

(3) 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. 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 as of December 31, 2017.

## 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 at IDACORP – Director Independence and Executive Sessions" to be filed pursuant to Regulation 14A for the 2018 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 2018 annual meeting of shareholders is hereby incorporated by reference.

***Idaho Power:*** The table below presents the aggregate fees of Idaho Power's 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, 2017 and 2016:

| | 2017 | 2016 |
|---|---|---|
| Audit fees | $ 1,379,000 | $ 1,344,108 |
| Audit-related fees[1] | 39,400 | 25,000 |
| Tax fees[2] | 40,000 | 4,117 |
| All other fees[3] | 2,000 | 2,000 |
| Total | $ 1,460,400 | $ 1,375,225 |

(1) Includes accounting-related consultation services in 2017 and agreed-upon procedures in connection with Bonneville Power Administration's evaluation of Idaho Power's compliance with its Residential Exchange Program in 2016.

(2) Includes fees for 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 2017 and 2016, 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 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 | 33-56071-99 | 3(d) | 10/1/1998 | |
| 3.5 | Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000 | 10-Q | 1-3198 | 3(a)(iii) | 8/4/2000 | |
| 3.6 | Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005 | 8-K | 1-3198 | 3.3 | 1/26/2005 | |
| 3.7 | Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007 | 8-K | 1-3198 | 3.3 | 11/19/2007 | |

| Exhibit No. | Exhibit Description | Incorporated by Reference Form | File No. | Exhibit No. | Date | Included Herewith |
|---|---|---|---|---|---|---|
| 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* | | | | | |
| | 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* | | | | | |

| Exhibit No. | Exhibit Description | Incorporated by Reference Form | File No. | Exhibit No. | Date | Included Herewith |
|---|---|---|---|---|---|---|
| | 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 | | | | | |
| | File number 1-3198, Form 8-K filed on 9/27/2016, as Exhibit 4.1, Forty-eighth, September 1, 2016 | | | | | |
| 4.3 | Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.16) | 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 | Amended and Restated Agreement for the Operation of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp | 10-K | 1-14465, 1-3198 | 10.4 | 2/19/2015 | |
| 10.2 | Amended and Restated Agreement for the Ownership of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp | 10-K | 1-14465, 1-3198 | 10.5 | 2/19/2015 | |
| 10.3 | 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 | |
| 10.4 | Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.13 | S-3 | 33-65720* | 10(h)(i) | 7/7/1993 | |

| Exhibit No. | Exhibit Description | Incorporated by Reference Form | File No. | Exhibit No. | Date | Included Herewith |
|---|---|---|---|---|---|---|
| 10.5 | Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.13 | S-3 | 33-65720* | 10(h)(ii) | 7/7/1993 | |
| 10.6 | Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.13 | 10-Q | 1-14465* | 10.58 | 5/7/2009 | |
| 10.7 | 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 | |
| 10.8 | Credit Agreement, dated November 6, 2015, among IDACORP, Inc., 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein | 8-K | 1-14465, 1-3198 | 10.1 | 11/9/2015 | |
| 10.9 | Credit Agreement, dated November 6, 2015, among Idaho Power Company, 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein | 8-K | 1-14465, 1-3198 | 10.2 | 11/9/2015 | |
| 10.10 | Letter Agreement, effective as of November 7, 2016, among IDACORP, Inc., 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein, extending term of Credit Agreement | 10-K | 1-14465, 1-3198 | 10.20 | 2/23/2017 | |
| 10.11 | Letter Agreement, effective as of November 7, 2016, among Idaho Power Company, 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein, extending term of Credit Agreement | 10-K | 1-14465, 1-3198 | 10.21 | 2/23/2017 | |
| 10.12 | Letter Agreement, effective as of November 7, 2017, among IDACORP, Inc., 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc. and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein, extending the term of the Credit Agreement | | | | | X |

| Exhibit No. | Exhibit Description | Incorporated by Reference Form | File No. | Exhibit No. | Date | Included Herewith |
|---|---|---|---|---|---|---|
| 10.13 | Letter Agreement, effective as of November 7, 2017, among Idaho Power Company, 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 MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc. and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein, extending the term of the Credit Agreement | | | | | X |
| 10.14 | Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company | 8-K | 1-3198 | 10.1 | 10/10/2006 | |
| 10.15 | 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 | |
| 10.16 | 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 | |
| 10.17[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 | |
| 10.18[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 | |
| 10.19[1] | Idaho Power Company Security Plan for Senior Management Employees II, as amended and restated February 8, 2017 | 10-K | 1-14465, 1-3198 | 10.31 | 2/23/2017 | |
| 10.20[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 | |
| 10.21[1] | IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 19, 2015 | 10-K | 1-14465, 1-3198 | 10.34 | 2/18/2016 | |
| 10.22[1] | IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 16, 2017 | | | | | X |
| 10.23[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 | |
| 10.24[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 | |
| 10.25[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 | |
| 10.26[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 | |
| 10.27[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 | |
| 10.28[1] | IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 8, 2018 | | | | | X |
| 10.29[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended and restated February 9, 2017 | 10-K | 1-14465, 1-3198 | 10.41 | 2/23/2017 | |
| 10.30[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Unit Award Agreement (Time Vesting) | 10-K | 1-14465, 1-3198 | 10.42 | 2/23/2017 | |

| Exhibit No. | Exhibit Description | Incorporated by Reference Form | File No. | Exhibit No. | Date | Included Herewith |
|---|---|---|---|---|---|---|
| 10.31[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Total Shareholder Return Goal) | 10-K | 1-14465, 1-3198 | 10.43 | 2/23/2017 | |
| 10.32[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Cumulative Earnings Per Share Goal) | 10-K | 1-14465, 1-3198 | 10.44 | 2/23/2017 | |
| 10.33[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting) (For 2016 Outstanding Awards) | 10-K | 1-14465, 1-3198 | 10.43 | 2/19/2015 | |
| 10.34[1] | IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals) (For 2016 Outstanding Awards) | 10-K | 1-14465, 1-3198 | 10.44 | 2/19/2015 | |
| 10.35[1] | IDACORP, Inc. Executive Incentive Plan, as amended and restated February 11, 2016 | 10-K | 1-14465, 1-3198 | 10.47 | 2/18/2016 | |
| 10.36[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 | |
| 10.37[1] | IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2018 | | | | | X |
| 10.38[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 | |
| 10.39[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 | |
| 10.40[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 | |
| 10.41[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 | |
| 10.42[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 | |
| 10.43[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 | |
| 10.44[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 | |
| 10.45[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 | |
| 10.46[1] | Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016 | 10-K | 1-14465, 1-3198 | 10.59 | 2/18/2016 | |
| 10.47[1] | Amendment, dated effective December 1, 2016, to the Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016 | 10-K | 1-14465, 1-3198 | 10.61 | 2/23/2017 | |
| 10.48[1] | Amendment to the Idaho Power Company Security Plan for Senior Management Employees II, as amended May 17, 2017 | 10-Q | 1-14465, 1-3198 | 10.1 | 8/3/2017 | |
| 10.49[1] | Second Amendment to the Idaho Power Company Employee Savings Plan, as amended January 1, 2018 | 10-Q | 1-14465, 1-3198 | 10.1 | 11/2/2017 | |
| 12.1 | IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges | | | | | X |
| 12.2 | Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges | | | | | X |
| 21.1 | Subsidiaries of IDACORP, Inc. | | | | | X |
| 23.1 | Consent of Registered Independent Accounting Firm | | | | | X |
| 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 |

| Exhibit No. | Exhibit Description | Incorporated by Reference | | | | Included Herewith |
|---|---|---|---|---|---|---|
| | | Form | File No. | Exhibit No. | Date | |
| 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 |

* Exhibit originally filed with the U.S. Securities and Exchange Commission in paper format and as such, a hyperlink is not available.
(1) Management contract or compensatory plan or arrangement

## ITEM 16. FORM 10-K SUMMARY

None.

**IDACORP, INC.**
**SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT**

**CONDENSED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| | (thousands of dollars) | | |
| **Income:** | | | |
| Equity in income of subsidiaries | $ 211,974 | $ 198,061 | $ 194,426 |
| Investment income | 26 | 3 | 1 |
| Total income | 212,000 | 198,064 | 194,427 |
| **Expenses:** | | | |
| Operating expenses | 708 | 716 | 831 |
| Interest expense | 294 | 333 | 276 |
| Other expenses | 30 | 45 | 45 |
| Total expenses | 1,032 | 1,094 | 1,152 |
| **Income from Before Income Taxes** | 210,968 | 196,970 | 193,275 |
| **Income Tax Benefit** | (1,451) | (1,318) | (1,404) |
| **Net Income Attributable to IDACORP, Inc.** | 212,419 | 198,288 | 194,679 |
| Other comprehensive (loss) income | (5,990) | 394 | 2,882 |
| **Comprehensive Income Attributable to IDACORP, Inc.** | $ 206,429 | $ 198,682 | $ 197,561 |

The accompanying note is an integral part of these statements.

**IDACORP, INC.**
**CONDENSED STATEMENTS OF CASH FLOWS**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| | (thousands of dollars) | | |
| **Operating Activities:** | | | |
| Net cash provided by operating activities | $ 113,849 | $ 139,077 | $ 100,465 |
| **Investing Activities:** | | | |
| Net cash provided by (used in) investing activities | — | — | — |
| **Financing Activities:** | | | |
| Dividends on common stock | (113,127) | (104,985) | (96,810) |
| Decrease in short-term borrowings | — | (20,000) | (11,300) |
| Change in intercompany notes payable | 17,097 | 2,421 | 5,572 |
| Other | (3,321) | (3,422) | (1,675) |
| Net cash used in financing activities | (99,351) | (125,986) | (104,213) |
| Net increase (decrease) in cash and cash equivalents | 14,498 | 13,091 | (3,748) |
| Cash and cash equivalents at beginning of year | 15,119 | 2,028 | 5,776 |
| Cash and cash equivalents at end of year | $ 29,617 | $ 15,119 | $ 2,028 |

The accompanying note is an integral part of these statements.

**IDACORP, INC.**
**CONDENSED BALANCE SHEETS**

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| **Assets** | (thousands of dollars) | |
| **Current Assets:** | | |
| Cash and cash equivalents | $ 29,617 | $ 15,119 |
| Receivables | 52,359 | 1,065 |
| Income taxes receivable | — | — |
| Other | 98 | 101 |
| Total current assets | 82,074 | 16,285 |
| **Investment in subsidiaries** | 2,189,017 | 2,098,818 |
| **Other Assets:** | | |
| Deferred income taxes | 34,040 | 66,411 |
| Other | 374 | 385 |
| Total other assets | 34,414 | 66,796 |
| Total assets | $ 2,305,505 | $ 2,181,899 |
| **Liabilities and Shareholders' Equity** | | |
| **Current Liabilities:** | | |
| Notes payable | $ — | $ — |
| Accounts payable | 17 | 6 |
| Taxes accrued | 17,423 | 8,476 |
| Other | 626 | 660 |
| Total current liabilities | 18,066 | 9,142 |
| **Other Liabilities:** | | |
| Intercompany notes payable | 35,140 | 17,834 |
| Other | 914 | 1,017 |
| Total other liabilities | 36,054 | 18,851 |
| **IDACORP, Inc. Shareholders' Equity** | 2,251,385 | 2,153,906 |
| Total Liabilities and Shareholders' Equity | $ 2,305,505 | $ 2,181,899 |

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 U.S. 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 2017 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 $116 million, $108 million, and $99 million in 2017, 2016, and 2015, respectively.

**IDACORP, INC.**
**SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**Years Ended December 31, 2017, 2016, and 2015**

| 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) | | |
| **2017:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 1,132 | $ 5,753 | $ 324 | $ 5,016 | $ 2,193 |
| Reserve for uncollectible notes | 402 | — | — | — | 402 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,792 | 687 | — | 1,010 | 1,469 |
| **2016:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 1,355 | $ 3,917 | $ 263 | $ 4,403 | $ 1,132 |
| Reserve for uncollectible notes | 552 | — | — | 150 | 402 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,874 | 848 | — | 930 | 1,792 |
| **2015:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 2,104 | $ 3,327 | $ 819 | $ 4,895 | $ 1,355 |
| Reserve for uncollectible notes | 552 | — | — | — | 552 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,995 | 890 | — | 1,011 | 1,874 |

[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 reserved.

**IDAHO POWER COMPANY**
**SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**Years Ended December 31, 2017, 2016, and 2015**

| 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) | | | |
| **2017:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 1,132 | $ 5,753 | $ 324 | $ 5,016 | $ 2,193 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,792 | 687 | — | 1,010 | 1,469 |
| **2016:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 1,355 | $ 3,917 | $ 263 | $ 4,403 | $ 1,132 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,874 | 848 | — | 930 | 1,792 |
| **2015:** | | | | | |
| Reserves deducted from applicable assets | | | | | |
| Reserve for uncollectible accounts | $ 2,104 | $ 3,327 | $ 819 | $ 4,895 | $ 1,355 |
| Other Reserves: | | | | | |
| Injuries and damages | 1,995 | 890 | — | 1,011 | 1,874 |

(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 reserved.

## 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 22, 2018
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*<br>Robert A. Tinstman | Chairman of the Board | February 22, 2018 |
| */s/ Darrel T. Anderson*<br>Darrel T. Anderson<br>President and Chief Executive Officer and Director | (Principal Executive Officer) | February 22, 2018 |
| */s/ Steven R. Keen*<br>Steven R. Keen<br>Senior Vice President, Chief Financial Officer, and Treasurer | (Principal Financial Officer) | February 22, 2018 |
| */s/ Kenneth W. Petersen*<br>Kenneth W. Petersen<br>Vice President, Controller, and Chief Accounting Officer | (Principal Accounting Officer) | February 22, 2018 |
| */s/ Thomas Carlile*<br>Thomas Carlile | Director | February 22, 2018 |
| */s/ Richard J. Dahl*<br>Richard J. Dahl | Director | February 22, 2018 |
| */s/ Annette G. Elg*<br>Annette G. Elg | Director | February 22, 2018 |
| */s/ Ronald W. Jibson*<br>Ronald W. Jibson | Director | February 22, 2018 |
| */s/ Judith A. Johansen*<br>Judith A. Johansen | Director | February 22, 2018 |
| */s/ Dennis L. Johnson*<br>Dennis L. Johnson | Director | February 22, 2018 |
| */s/ J. LaMont Keen*<br>J. LaMont Keen | Director | February 22, 2018 |
| */s/ Christine King*<br>Christine King | Director | February 22, 2018 |
| */s/ Richard J. Navarro*<br>Richard J. Navarro | Director | February 22, 2018 |

## 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 22, 2018
Date

Idaho Power Company

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*<br>Robert A. Tinstman | Chairman of the Board | February 22, 2018 |
| */s/ Darrel T. Anderson*<br>Darrel T. Anderson<br>President and Chief Executive Officer and Director | (Principal Executive Officer) | February 22, 2018 |
| */s/ Steven R. Keen*<br>Steven R. Keen<br>Senior Vice President, Chief Financial Officer, and Treasurer | (Principal Financial Officer) | February 22, 2018 |
| */s/ Kenneth W. Petersen*<br>Kenneth W. Petersen<br>Vice President, Controller, and Chief Accounting Officer | (Principal Accounting Officer) | February 22, 2018 |
| */s/ Thomas Carlile*<br>Thomas Carlile | Director | February 22, 2018 |
| */s/ Richard J. Dahl*<br>Richard J. Dahl | Director | February 22, 2018 |
| */s/ Annette G. Elg*<br>Annette G. Elg | Director | February 22, 2018 |
| */s/ Ronald W. Jibson*<br>Ronald W. Jibson | Director | February 22, 2018 |
| */s/ Judith A. Johansen*<br>Judith A. Johansen | Director | February 22, 2018 |
| */s/ Dennis L. Johnson*<br>Dennis L. Johnson | Director | February 22, 2018 |
| */s/ J. LaMont Keen*<br>J. LaMont Keen | Director | February 22, 2018 |
| */s/ Christine King*<br>Christine King | Director | February 22, 2018 |
| */s/ Richard J. Navarro*<br>Richard J. Navarro | Director | February 22, 2018 |

## IDACORP & Idaho Power

( ) total years of service

**Darrel T. Anderson** (22)
President and Chief Executive Officer, IDACORP, Inc. and Idaho Power

**Brian R. Buckham** (7)
Senior Vice President and General Counsel

**Patrick A. Harrington** (32)
Corporate Secretary

**Steven R. Keen** (35)
Senior Vice President, Chief Financial Officer and Treasurer

**Jeffrey Malmen** (10)
Senior Vice President of Public Affairs

**Ken W. Petersen** (19)
Vice President, Controller and Chief Accounting Officer

## Idaho Power

**Lisa A. Grow** (30)
Senior Vice President of Operations and Chief Operating Officer

**Jeffrey Glenn** (2)
Vice President of Information Technology and Chief Information Officer

**Lonnie Krawl** (12)
Senior Vice President of Administrative Services and Chief Human Resources Officer

**Tessia Park** (20)
Vice President of Power Supply

**N. Vern Porter** (28)
Vice President of T&D Engineering and Chief Safety Officer

**Adam J. Richins** (6)
Vice President of Customer Operations and Business Development

**Tim E. Tatum** (22)
Vice President of Regulatory Affairs

IDACORP, Inc., Boise, Idaho-based and formed in 1998, is a holding company composed of Idaho Power, 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. Idaho Power began operations in 1916 and 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 545,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about IDACORP or Idaho Power, visit idacorpinc.com or idahopower.com.

**Forward-Looking Statements:** Please refer to IDACORP's and Idaho Power's Annual Report on 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
EQ 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, 11 Wall St.
New York, NY 10005

### Contacts

Broker/Analyst Contact: Justin S. Forsberg
Director of Investor Relations
Phone: 208-388-2728, Fax: 208-433-4782
Email: jforsberg@idacorpinc.com

Shareowner Contact: Colette Shepard
Phone: 1-800-635-5406, 208-388-2564, Fax: 208-388-6955
Email: cshepard@idacorpinc.com

### Corporate Headquarters

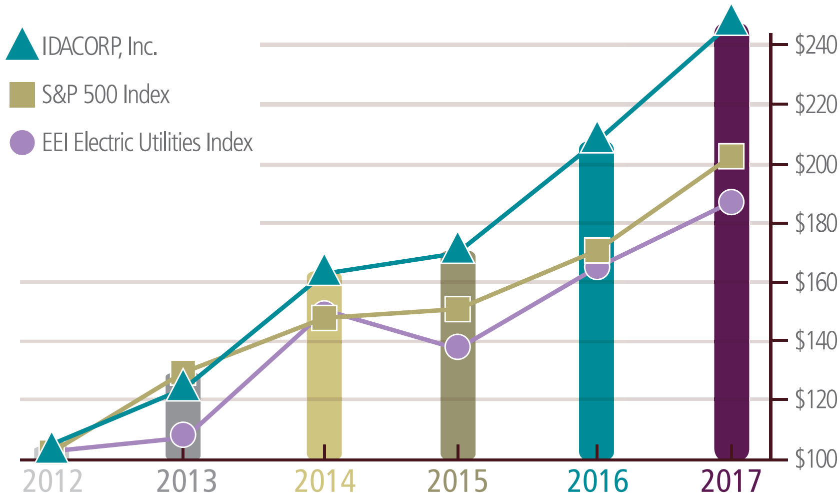
Mailing: P.O. Box 70, Boise, ID 83707-0070
Street: 1221 W. Idaho St., Boise, ID 83702-5627
Phone: 208-388-2200
Website: idacorpinc.com

### SEC Form 10-K

The IDACORP, Inc. and Idaho Power 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 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.

### 2018 Annual Meeting

The 2018 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 17, 2018. Formal notice of the meeting will be mailed to shareholders on or about Monday, April 2, 2018.




# COMPARISON OF CUMULATIVE TOTAL RETURN

$100 Invested Dec. 31, 2012 Period Ended Dec. 31, 2017

IDACORP

P.O. Box 70
Boise, ID 83707-0070

www.idacorpinc.com