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

Form 1 Approved
OMB No. 1902-0021
(Expires 6/30/2007)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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 2004/Q4

Deloitte.

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

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

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the balance sheet-regulatory basis of Idaho Power Company (the "Company") as of December 31, 2004, and the related statements of income-regulatory basis; retained earnings-regulatory basis; cash flows-regulatory basis; and accumulated comprehensive income, comprehensive income, and hedging activities—regulatory basis for the year ended December 31, 2004, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted 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 of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

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

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities and proprietary capital of Idaho Power Company as of December 31, 2004, and the results of its operations and its cash flows for the year ended December 31, 2004, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the Board of Directors and management of Idaho Power 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

March 8, 2005

INSTRUCTIONS FOR FILING FERC FORMS 1, 1-F and 3-Q

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101), must submit Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 141.400.

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus Losses).

Nonmajor means having in each of the three `previous calendar years, total annual sales of 10,000 megawatt hours or more

III. What and Where to Submit

(a) Submit Forms 1, 1-F and 3-Q electronically through the Form 1/3-Q Submission Software. Retain one copy of each report for your files.
(b) Respondents may submit the Corporate Officer Certification electronically, or file/mail an original signed Corporate Officer Certification to:

Chief Accountant
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(c) Submit, immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 1, Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to the address in III(c) above.

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 CFR 158.10-158.12 for specific qualifications.)

Reference Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

Insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the address indicated at III (b). Use the following form for the letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied. insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statements of for the year ended on which we have reported separately under date of We have also reviewed schedules of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist

.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from: Public Reference and Files Maintenance Branch Federal Energy Regulatory Commission 888 First Street, NE. Room 2A ED-12.2 Washington, DC 20426 (202).502-8371

IV. When to Submit:

Submit Form 1 according to the filing dates contained in section 18 CFR 141.1 of the Commission's regulations. Submit Form 1-F according to the filing dates contained in section 18 CFR 141.2 of the Commission's regulations. Submit Form 3-Q according to the filing dates contained in section 18 CFR 141.400 of the Commission's regulations.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information.public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 150 hours per response. Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Mr. Michael Miller, ED-30); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the Form 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.
FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.
LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.
OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.
SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.
NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.
OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service form. Describe the type of service in a footnote for each entry.
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.

DEFINITIONS

I. Commision Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

Federal Power Act, 16 U.S.C. 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit: ... (3) . corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shalt not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry an the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning ;he utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission my prescribe the manner and form in which such reports shalt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the *form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act .... shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing .... "

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2004/Q4
03 Previous Name and Date of Change *(if name changed during year)* Idaho Power Company	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070	
05 Name of Contact Person Darrel Anderson	06 Title of Contact Person Senior VP of Admin Ser & CFO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2650	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed
Darrel Anderson	Darel Anderson	*(Mo, Da, Yr)*
02 Title Senior VP of Admin Ser & CFO	Darrel Anderson	04/22/2005

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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".

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	
46	Transmission of Electricity by Others	332	
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
50	Research, Development and Demonstration Activities	352-353	
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	None
53	Purchases and Sales of Ancillary Services	398	
54	Monthly Transmission System Peak Load	400	
55	Electric Energy Account	401	
56	Monthly Peaks and Output	401	
57	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
58	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	None
59	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	
60	Generating Plant Statistics (Small Plants)	410-411	
61	Transmission Line Statistics	422-423	
62	Transmission Lines Added During Year	424-425	
63	Substations	426-427	
64	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.

Darrel Anderson Senior Vice President of Administration and CFO, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
"	Oregon

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

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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	04/22/2005	End of 2004/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	Jan B. Packwood	580,000
3			
4	President and Chief Operating Officer	J. LaMont Keen	350,000
5			
6	Vice President, General Counsel and Secretary	Robert W. Stahman (1)	200,000
7			
8	Sr Vice President, Power Supply	James C. Miller	250,000
9			
10	Sr Vice President, General Counsel and Secretary	Thomas Saldin (2)	53,800
11			
12	Senior Vice President Administration & CFO	Darrel T Anderson	210,000
13			
14	Vice President , Power Supply	John P Prescott (3)	101,700
15			
16	Vice President and Chief Information Officer	A. Bryan Kearny	183,000
17			
18	Vice President Delivery	Dan Minor	170,000
19			
20	Vice President, Human Resources	Luci McDonald	5,800
21			
22	Vice President, Regulatory Affairs	Ric Gale	140,000
23			
24	Vice President, Public Affairs	Greg Panter	138,000
25			
26	Vice President, Treasurer	Dennis Gribble	139,300
27			
28	Vice President , Finance and Chief Risk Officer	Lori Smith	135,000
29			
30	(1) Resigned January 2005		
31	(2) Took office October 2004		
32	(3) Resigned July 2004		
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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	04/22/2005	End of 2004/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Rotchford L. Barker	P.O. Box 2080, Cody Wyoming 82414
2		
3	Jack K. Lemley ***	Lemley & Associates, Inc.
4		1508 N. 13th, Boise, Idaho 83702
5		
6	Gary Michael	P.O. Box 1718 Boise Idaho 83701
7		
8	Jon H. Miller, Chairman of the Board***	P.O. Box 1557, Boise, Idaho 83701
9		
10	Peter S. O'Neill	O'Neill Enterprises, Inc.
11		871 E. Parkcenter Blvd., Boise, Idaho 83706
12		
13	Jan B. Packwood President and CEO **	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	J. LaMont Keen President and Chief Operating Officer	Idaho power Company, 1221 W. Idaho Street,
17		P.O. Box 70, Boise, Idaho 83707-0070
18		
19	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho, 83703
20		
21	Christopher L. Culp (1)	1400 North Lake Shore Drive,#8B, Chicago, IL 60610
22		
23	Richard G. Reiten	NW Natural 220 NW 2nd Ave - 13th floor, Portland, Oregon 97209
24		
25	Thomas Wilford	Alscott Inc, 501 Baybrook Court Boise, Idaho 83706
26		
27	Joan Smith (2)	2309 S.W. Avenue, No. 1141, Portland, OR 97201
28		
29	(1) Resigned January 2005.	
30	(2) Took Office December 2004	
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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SEE PAGE 109 FOR REQUIRED INFORMATION.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. Relicensing costs closed to account 302 $1,253,778

2. Three new distribution substations in service March 2004, Midrose, Star & Vallivue.

3. New transmission line connects Caldwell, Garnet & Locust Substation - 20.1 miles.

4. None

5. None

6. Issued $55 million of 5.50% First Mortgage Bonds maturing 08-16-34, Issued 08-16-04 under OPUC Order UF4196, Wyoming Docket 2005-ES-03-24 and IPUC case #IPC-E-03-3.

Issued $50 million of 5.875% First Mortgage Bonds maturing 03-15-34, Issued 03-26-04 under OPUC Order UF4196, Wyoming Docket 2005-ES-03-24 and IPUC case #IPC-E-03-3.

7. None

8. On December 29, 2004 a general wage increase of 3.5%.

9. See pages 123.8 thru 123.16

10. None

11. None

12. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	3,327,451,494	3,222,666,339
3	Construction Work in Progress (107)	200-201	151,651,719	96,086,154
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,479,103,213	3,318,752,493
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,316,124,554	1,239,604,536
6	Net Utility Plant (Enter Total of line 4 less 5)		2,162,978,659	2,079,147,957
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,162,978,659	2,079,147,957
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		828,002	828,832
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	36,544,480	27,417,179
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)		32,458,340	14,225
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		27,507,094	23,054,733
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		97,337,916	51,314,969
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		359,186	409,251
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		57,457	80,657
38	Temporary Cash Investments (136)		17,236,000	3,508,000
39	Notes Receivable (141)		11,863,100	12,982,368
40	Customer Accounts Receivable (142)		45,440,589	43,693,876
41	Other Accounts Receivable (143)		5,201,303	4,840,397
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,363,426	1,465,615
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,297,952	1,143,083
45	Fuel Stock (151)	227	6,450,733	6,228,205
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	25,378,777	18,788,326
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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	685,830	966,741
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)		28,448,966	26,834,791
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		52,040	7,218
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		33,832,290	30,868,672
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		87,506	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	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)		175,028,303	148,885,970
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		7,741,547	6,500,343
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	438,780,828	434,028,467
73	Prelim. Survey and Investigation Charges (Electric) (183)		91,953	91,953
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)		12,057	-143,007
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	83,272,850	98,056,892
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)		15,193,036	16,386,031
82	Accumulated Deferred Income Taxes (190)	234	72,712,115	61,337,131
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		617,804,386	616,257,810
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,053,149,264	2,895,606,706

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☐ A Rresubmission	04/22/2005	end of 2004/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	52,366,400
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	483,707,554	397,965,246
7	Other Paid-In Capital (208-211)	253	0	265,534
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)	254	2,096,925	2,686,058
11	Retained Earnings (215, 215.1, 216)	118-119	309,178,039	297,996,861
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	30,928,808	22,738,561
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)	-887,774	-2,629,165
16	Total Proprietary Capital (lines 2 through 15)		918,706,732	863,894,409
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	955,460,000	900,460,000
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	31,585,000	32,690,015
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,135,446	2,205,072
24	Total Long-Term Debt (lines 18 through 23)		983,909,554	930,944,943
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)		1,797,494	831,488
29	Accumulated Provision for Pensions and Benefits (228.3)		10,592,032	3,929,788
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	12,015,187
31	Accumulated Provision for Rate Refunds (229)		400,102	1,514,466
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)		9,287,789	7,139,812
35	Total Other Noncurrent Liabilities (lines 26 through 34)		22,077,417	25,430,741
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		72,530,597	44,717,259
39	Notes Payable to Associated Companies (233)		20,469,707	9,021,024
40	Accounts Payable to Associated Companies (234)		278,488	75,401
41	Customer Deposits (235)		1,000,351	1,295,924
42	Taxes Accrued (236)	262-263	40,280,158	52,867,442
43	Interest Accrued (237)		13,742,553	12,892,588
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) ☐ An Original (2) ☐ A Rresubmission	04/22/2005	end of 2004/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,111,305	812,200
48	Miscellaneous Current and Accrued Liabilities (242)		17,015,195	19,598,441
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		445	89,923
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)		167,428,799	141,370,202
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		15,073,749	11,658,799
57	Accumulated Deferred Investment Tax Credits (255)	266-267	66,836,156	67,788,977
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	56,257,710	55,025,978
60	Other Regulatory Liabilities (254)	278	209,105,349	190,734,675
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)		585,543,346	569,434,622
64	Accum. Deferred Income Taxes-Other (283)		28,210,452	39,323,361
65	Total Deferred Credits (lines 56 through 64)		961,026,762	933,966,412
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,053,149,264	2,895,606,707

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

STATEMENT OF INCOME

1. Enter in column (e) operations for the reporting quarter and in column (f) the operations for the same three month period for the prior year.
2. Report in Column (g) year to date amounts for electric utility function; in column (i) the year to date amounts for gas utility, and in (k) the year to date amounts for the other utility function for the current quarter/year.
3. Report in Column (h) year to date amounts for electric utility function; in column (j) the year to date amounts for gas utility, and in (l) the year to date amounts for the other utility function for the previous quarter/year.
4. If additional columns are needed place them in a footnote.

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	800,822,106	780,381,662	176,034,120	235,768,467
3	Operating Expenses					
4	Operation Expenses (401)	320-323	523,328,322	477,670,013	119,897,939	175,660,145
5	Maintenance Expenses (402)	320-323	58,404,718	62,798,431	12,945,287	14,335,983
6	Depreciation Expense (403)	336-337	90,986,890	87,913,155	23,201,849	22,741,884
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	10,050,731	9,846,878	2,199,122	2,614,692
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723	-5,681	-5,681
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		19,944		4,986	4,986
13	(Less) Regulatory Credits (407.4)		18,949,682		14,418,138	4,451,768
14	Taxes Other Than Income Taxes (408.1)	262-263	19,090,214	20,752,763	3,553,897	4,593,285
15	Income Taxes - Federal (409.1)	262-263	16,305,814	40,987,586	-3,860,503	-11,143,156
16	- Other (409.1)	262-263	7,273,792	7,251,532	785,371	1,181,777
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	28,170,120	41,049,257	15,887,587	4,903,465
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	45,142,816	62,485,541	7,403,600	10,162,516
19	Investment Tax Credit Adj. - Net (411.4)	266	-952,821	229,367	-492,368	-153,483
20	(Less) Gains from Disp. of Utility Plant (411.6)					-3,249
21	Losses from Disp. of Utility Plant (411.7)		-2,071	20,012		2,310
22	(Less) Gains from Disposition of Allowances (411.8)		158,330	106,845		127,763
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		688,402,102	685,903,885	152,295,748	199,997,409
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		112,420,004	94,477,777	23,738,372	35,771,058

STATEMENT OF INCOME FOR THE YEAR (Continued)

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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
800,822,106	780,381,662					2
						3
523,328,322	477,670,013					4
58,404,718	62,798,431					5
90,986,890	87,913,155					6
						7
10,050,731	9,846,878					8
-22,723	-22,723					9
						10
						11
19,944						12
18,949,682						13
19,090,214	20,752,763					14
16,305,814	40,987,586					15
7,273,792	7,251,532					16
28,170,120	41,049,257					17
45,142,816	62,485,541					18
-952,821	229,367					19
						20
-2,071	20,012					21
158,330	106,845					22
						23
						24
688,402,102	685,903,885					25
112,420,004	94,477,777					26

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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	04/22/2005	End of 2004/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		112,420,004	94,477,777	23,738,372	35,771,058
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,427,754	2,337,845	966,866	968,046
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,388,329	2,153,982	1,020,637	760,580
33	Revenues From Nonutility Operations (417)		110,035		30,739	32,473
34	(Less) Expenses of Nonutility Operations (417.1)		279,748	471,049	130,157	-63,502
35	Nonoperating Rental Income (418)		-2,136	201	-90	-448
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,190,247	10,047,927	1,896,387	2,617,211
37	Interest and Dividend Income (419)		2,412,553	3,406,756	644,914	696,560
38	Allowance for Other Funds Used During Construction (419.1)		3,904,027	3,384,923	965,556	912,162
39	Miscellaneous Nonoperating Income (421)		5,624,756	2,500,487	2,709,058	978,345
40	Gain on Disposition of Property (421.1)		469,258	11,433	58,702	218,996
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		20,468,417	19,064,541	6,121,338	5,726,267
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		7,207		115	7,092
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	538,360	616,439	182,972	143,214
46	Life Insurance (426.2)		-671,031	-247,517	-104,539	-13,419
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		550,041	461,809	277,365	150,174
49	Other Deductions (426.5)		13,923,708	4,680,702	542,772	1,200,000
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		14,348,285	5,511,433	898,685	1,487,061
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	38,712	21,049	15,669	7,695
53	Income Taxes-Federal (409.2)	262-263	144,957	13,728,193	514,146	95,233
54	Income Taxes-Other (409.2)	262-263	43,666	3,663,709	104,968	24,474
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,586,407	6,129,204	452,395	382,669
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,482,592	29,991,831	218,938	480,332
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-3,668,850	-6,449,676	868,240	29,739
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		9,788,982	20,002,784	4,354,413	4,209,467
61	Interest Charges					
62	Interest on Long-Term Debt (427)		50,317,585	54,645,483	13,144,737	12,639,648
63	Amort. of Debt Disc. and Expense (428)		1,188,137	1,113,620	305,413	300,653
64	Amortization of Loss on Reaquired Debt (428.1)		1,192,994	1,287,891	290,174	290,174
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)	340	256,468	83,628	109,517	71,837
68	Other Interest Expense (431)	340	1,598,490	2,069,273	517,553	339,815
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,952,809	3,310,120	834,090	656,660
70	Net Interest Charges (Total of lines 62 thru 69)		51,600,865	55,889,775	13,533,304	12,985,467
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		70,608,121	58,590,786	14,559,481	26,995,058
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)		70,608,121	58,590,786	14,559,481	26,995,058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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		296,452,895	316,065,712
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Redemption of Preferred Stock		-1,888,289	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-1,888,289	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		62,417,874	48,542,859
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	4% Preferred (par value $100)	238	-437,394	(510,038)
25	7.68% Serial Preferred (par value $100)	238	-1,021,815	
26	7.07% Serial Preferred (par value $100)	238	-1,475,750	(1,152,000)
27				(1,767,500)
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-2,934,959	(3,429,538)
30	Dividends Declared-Common Stock (Account 438)			
31	$2.50 Par Value		-46,413,448	(64,726,138)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-46,413,448	(64,726,138)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		307,634,073	296,452,895
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)		1,543,966	1,543,966
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,543,966	1,543,966
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		309,178,039	297,996,861
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		22,738,561	12,690,634
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,190,247	10,047,927
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		30,928,808	22,738,561

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	70,608,121	58,590,786
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	90,986,890	107,764,506
5	Amortization of	17,564,230	2,463,983
6			
7			
8	Deferred Income Taxes (Net)	-21,373,450	-46,516,708
9	Investment Tax Credit Adjustment (Net)	-952,821	229,366
10	Net (Increase) Decrease in Receivables	-4,049,547	21,640,701
11	Net (Increase) Decrease in Inventory	-587,583	2,418,095
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	14,699,394	-37,935,220
14	Net (Increase) Decrease in Other Regulatory Assets	17,122,666	64,278,170
15	Net Increase (Decrease) in Other Regulatory Liabilities	-334,354	1,441,315
16	(Less) Allowance for Other Funds Used During Construction	3,904,027	3,384,923
17	(Less) Undistributed Earnings from Subsidiary Companies	9,127,301	12,309,546
18	Other (provide details in footnote):	15,690,324	
19	Unbilled Revenues		4,845,213
20	Other than temporary decline in market value of investments		-408,259
21	Other Net		12,355,504
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	186,342,542	175,472,983
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-187,333,369	-144,936,000
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	2,952,809	3,310,120
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-190,286,178	-148,246,120
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	831	221,557
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-295,355,514	
45	Proceeds from Sales of Investment Securities (a)	266,331,185	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	-39,409	
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):		
54	Note reveivable payment to parent		21,827,722
55	Other Net		-97,321
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-219,349,085	-126,294,162
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	105,000,000	189,800,000
62	Preferred Stock		
63	Common Stock		39,986,708
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	11,448,683	
67	Other (provide details in footnote):	85,920,000	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	202,368,683	229,786,708
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-50,000,000	-209,800,000
74	Preferred Stock	-52,350,828	-859,941
75	Common Stock		
76	Other (provide details in footnote):	-2,119,881	-490,613
77			-4,186,800
78	Net Decrease in Short-Term Debt (c)		-4,131,588
79			
80	Dividends on Preferred Stock	-4,823,248	-3,429,538
81	Dividends on Common Stock	-46,413,448	-64,726,138
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	46,661,278	-57,837,910
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	13,654,735	-8,659,089
87			
88	Cash and Cash Equivalents at Beginning of Period	3,997,908	12,656,997
89			
90	Cash and Cash Equivalents at End of period	17,652,643	3,997,908

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

Idaho Power Company

NOTE 1

	12 Months Ended 12/31/2004
Amortization of	
Plant	10,028,008
Regulatory Assets	5,092,539
Unamoritzed Debt Expense	987,010
Unamoritzed Discount	1,394,122
Other	62,551
	17,564,230

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NOTE 2

	12 Months Ended 12/31/2004
Cash Flow from Operating Activities (Other)	
Unbilled Revenues	(2,963,617)
Impairment of Assets	9,075,434
Other - Net	9,578,507
	15,690,324

Schedule Page: 120 Line No.: 67 Column: b

NOTE 3

	12 Months Ended 12/31/2004
Cash Flow from Financing Activities (Other)	
Capital Infusion from IDACORP, Inc. (parent)	85,920,000
	85,920,000

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NOTE 4

	12 Months Ended 12/31/2004
Cash Flow from Financing Activities (Other)	
Retirement of REA Notes	(1,105,015)
Other - Net	(1,014,866)
	(2,119,881)

NOTES TO FINANCIAL STATEMENTS

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Nature of Business

Idaho Power Company is an electric utility engaged in the generation, transmission, distribution, sale and purchase of electric energy. IPC is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co., a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. IERCO is not consolidated for FERC Form-1 reporting purposes.

Basis of Presentation

These financial statements were prepared in accordance with the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

System of Accounts

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

Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with accounting principles generally accepted in the United States of America. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual results could differ from those estimates.

System of Accounts

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

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFDC) and indirect charges for engineering, supervision and similar overhead items. Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are expensed to operations. Repair and maintenance costs associated with planned major maintenance are recorded as these costs are incurred. 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 2.96 percent in 2004 and 2.99 percent in 2003.

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 as prescribed under Statement of Financial Accounting Standards (SFAS) 144, "Accounting for the Impairment or Disposal of Long-lived Assets." SFAS 144 requires that if the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements.

Allowance for Funds Used During Construction

AFDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the rate-making 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 AFDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. IPC's weighted-average monthly AFDC rates for 2004 and 2003 were 6.9 percent and 8.3 percent, respectively. IPC's reductions to interest expense for AFDC were $3 million for both 2004 and 2003. Other income included $4 million and $3 million for 2004 and 2003, respectively.

Revenues

In order to match revenues with associated expenses, IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at month-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense.

Power Cost Adjustment
IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portion, is then included in the calculation of the next year's PCA.

Income Taxes
The liability method of computing deferred taxes is used on all temporary differences between the book and tax basis of assets and liabilities and deferred tax assets and liabilities are adjusted for enacted changes in tax laws or rates. Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction, IPC's deferred income taxes (commonly referred to as normalized accounting) are provided for the difference between income tax depreciation and straight-line depreciation computed using book lives on coal-fired generation facilities and properties acquired after 1980. On other facilities, deferred income taxes are provided for the difference between accelerated income tax depreciation and straight-line depreciation using tax guideline lives on assets acquired prior to 1981. Deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods do not provide for current recovery in rates. 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. See Note 2 for more information.

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.

Stock-Based Compensation
The following table illustrates the effect on net income if the fair value recognition provisions of SFAS 123 had been applied to stock-based employee compensation:

	2004	2003
	(thousands of dollars)	
Net income, as reported	$ 70,608	$ 58,591
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	276	(56)
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards ,net of related tax effects	977	1,073
Pro forma net income	$ 69,907	$ 57,462

Cash and Cash Equivalents
Cash and cash equivalents include cash on hand and highly liquid temporary investments with maturity dates at date of acquisition of three months or less.

Regulation of Utility Operations
IPC follows SFAS 71, "Accounting for the Effects of Certain Types of Regulation," and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating IPC. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the rate-making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers.

Comprehensive Income
Comprehensive income includes net income, unrealized holding gains and losses on marketable securities, IPC's proportionate share of unrealized holding gains and losses on marketable securities held by an equity investee and the changes in additional minimum liability under a deferred compensation plan for certain senior management employees and directors. The following table presents IPC's

accumulated other comprehensive loss balance at December 31:

	2004	2003
	(thousands of dollars)	
Unrealized holding gains on securities	$ 4,538	$ 3,676
Minimum pension liability adjustment	(5,426)	(6,306)
Total	$ (888)	$ (2,630)

Adopted Accounting Pronouncement

In January 2004, IPC adopted Financial Accounting Standards Board (FASB) Interpretation (FIN) 46R, "Consolidation of Variable Interest Entities - an interpretation of ARB No. 51," which addresses consolidation by business enterprises of VIEs, which have one or more of the following characteristics:

1. The equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including the equity holders;
2. The equity investors lack one or more of the following essential characteristics of a controlling financial interest:
   a. The direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights;
   The obligation to absorb the expected losses of the entity;
   The right to receive the expected residual returns of the entity; and
3. The equity investors have voting rights that are not proportionate to their economic interests, and the activities of the entity involve or are conducted on behalf of an investor with a disproportionately small voting interest.

IPC evaluated its investments, contracts and other potential variable interests that would be subject to the provisions of FIN 46R, and determined that the adoption did not have a material effect on its financial statements.

New Accounting Pronouncements

SFAS 151: In November 2004, the FASB issued SFAS 151, "Inventory Costs," which clarifies the accounting for certain inventory-related costs. SFAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005, and is not expected to have a material effect on IPC's financial statements.

SFAS 153: In December 2004, the FASB issued SFAS 153, "Exchanges of Nonmonetary Assets," which amends existing guidance on accounting for nonmonetary transactions. SFAS 153 is effective for exchanges occurring in fiscal periods beginning after June 15, 2005, and is not expected to have a material effect on IPC's financial statements.

SFAS 123(R): In December 2004, the FASB issued SFAS 123 (revised 2004), "Share-Based Payments," which revises SFAS 123 and supersedes APB 25 and its related implementation guidance. SFAS 123(R) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123(R) focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions.

Under the provisions of SFAS 123(R), the fair value of all stock options must be reported as an expense on the financial statements. IPC currently apply the measurement provisions of APB 25 and the disclosure-only provisions of SFAS 123. SFAS 123(R) also changes other measurement, timing and disclosure rules relating to share-based payments.

SFAS 123(R) is effective for most public entities as of the beginning of the first interim or annual reporting period beginning after June 15, 2005. IPC expects to adopt SFAS 123(R) on July 1, 2005, and adoption is expected to decrease IPC's pre-tax income by approximately $0.6 million in 2005. Stock-based compensation arrangements are discussed in Note 9.

FSP FAS 106-2: See Note 10 for a discussion of this FSP, which relates to postretirement benefit obligations.

Other Accounting Policies

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

Reclassifications
Certain items previously reported for years prior to 2004 have been reclassified to conform to the current year's presentation. Net income and shareholders' equity were not affected by these reclassifications.

2. INCOME TAXES:
A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2004	2003
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 25,394	$ 27,703
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,867)	(3,517)
AFDC	(2,400)	(2,343)
Investment tax credits	(3,295)	(3,397)
Repair allowance	(2,450)	(2,450)
Removal Cost	(1,244)	(1,101)
Pension Accrual	1,237	2,456
Capitalized overhead costs	(3,658)	(3,658)
Regulatory Tax Liability	(16,457)	-
Settlement of prior years tax returns	(1,460)	(6,208)
State income taxes, net of federal benefit	4,100	3,859
Depreciation	4,350	10,237
Other, Net	697	(1,020)
Total (benefit) provision for income taxes	$ 1,947	$ 20,561
Effective tax rate	2.7%	26.0%

The provision for income taxes consists of the following:

	2004	2003
	(thousands of dollars)	
Income taxes currently payable (receivable):		
Federal	$ 16,451	$ 54,716
State	7,318	10,915
Total	23,769	65,631
Income tax credits:		
Federal	(17,318)	(36,015)
State	(3,551)	(9,284)
Total	(20,869)	(45,299)
Investment tax credits:		
Federal	2,700	3,627
State	(3,653)	(3,398)
Total	(953)	229
Total (benefit) provision for income taxs	$ 1,947	$ 20,561

The tax effects of significant items comprising the Company's net deferred tax liabilities are:

	2004	2003
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liability	$ 40,447	$ 41,024

Advances for construction	5,357	4,162
Deferred compensation	12,324	9,385
Other	14,584	12,329
Total	72,712	66,900
Deferred tax liabilities:		
Property, plant and equipment	241,324	238,602
Regulatory asset	344,220	330,833
Conservation programs	6,972	8,310
PCA	20,516	27,529
Other	722	9,047
Total	613,754	614,321
Net deferred tax laibilities	$ 541,042	$ 547,421

Regulatory Settlement
In Settlement No. 2, as more fully discussed in Note 12, IPC and the IPUC finalized an income tax issue from IPC's 2003 Idaho general rate case. The issue concerned the regulatory accounting treatment for the capitalized overhead cost tax method IPC adopted in the 2001 IDACORP federal income tax return. As a result of Settlement No. 2, a $16 million regulatory tax liability was reversed to income tax expense in the third quarter of 2004.

American Jobs Creation Act of 2004: In October 2004, the president signed into law the American Jobs Creation Act of 2004 (the Act), which may have tax implications for IPC. One provision of the Act with potential implications for the companies relates to manufacturing tax incentives for the production of electricity beginning in 2005. Taxpayers will be able to deduct a percentage (three percent in 2005 and 2006, six percent in 2007 through 2009 and nine percent in 2010 and thereafter) of the lesser of their qualified production activities income or their taxable income. Management is currently reviewing this and other aspects of the Act to determine the impact on the company.

3. COMMON STOCK:
In December 2004, IDACORP contributed $86 million of additional equity to IPC. No additional shares of IPC common stock were issued in this transaction.

In December 2003, IPC issued 1,538,461 shares of $2.50 par value common stock to IDACORP for $40 million. Each share of IPC's common stock is entitled to one vote.

Dividend Restrictions
IPC's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. On September 20, 2004, IPC redeemed all of its outstanding preferred stock. Also, certain provisions of credit facilities contain restrictions on the ratio of debt to total capitalization.

IPC must obtain the approval of the Oregon Public Utility Commission (OPUC) before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

4. PREFERRED STOCK OF IDAHO POWER COMPANY:

The number of shares of IPC preferred stock outstanding at December 31 were as follows:

	Shares Outstanding at December 31, 2004	2003
Preferred stock:		
Cumulative, $100 par value:		
4% preferred stock (authorized 215,000 shares)	-	123,664
Serial preferred stock, 7.68% Series (authorized 150,000 shares)	-	150,000
Serial preferred stock, cumulative, without par value, total of 3,000,000 shares authorized:		
7.07% Series, $100 stated value (authorized 250,000 shares)	-	250,000

Total	-	523,664

On September 20, 2004, IPC redeemed all of its outstanding preferred stock for $54 million using proceeds from the issuance of first mortgage bonds. This amount includes $2 million of premium that was recorded as preferred dividends on the Consolidated Statements of Income. The redemption price was $104 per share for the 122,989 shares of 4% preferred stock, $102.97 per share for the 150,000 shares of 7.68% preferred stock and $103.18 per share for the 250,000 shares of 7.07% preferred stock, plus accumulated and unpaid dividends.

During 2003 IPC reacquired and retired 10,263 shares of 4% preferred stock.

5. LONG-TERM DEBT:

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

	2004	2003
	(thousands of dollars)	
First mortgage bonds:		
8 % Series due 2004	$ -	$ 50,000
5.83 % Series due 2005	60,000	60,000
7.38 % Series due 2007	80,000	80,000
7.20 % Series due 2009	80,000	80,000
6.60 % Series due 2011	120,000	120,000
4.75 % Series due 2012	100,000	100,000
4.25 % Series due 2013	70,000	70,000
6 % Series due 2032	100,000	100,000
5.50 % Series due 2033	70,000	70,000
5.50 % Series due 2034	50,000	-
5.875 % Series due 2034	55,000	-
Total first mortgage bonds	785,000	730,000
Pollution control revenue bonds:		
Variable Auction Rate Series 2003 due 2024 (a)	49,800	49,800
6.05 % Series 1996A due 2026	68,100	68,100
Variable Rate Series 1996B due 2026	24,200	24,200
Variable Rate Series 1996C due 2026	24,000	24,000
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
REA notes	-	1,105
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	11,700	11,700
Unamortized premium/discount - net	(3,135)	(2,205)
Total	983,910	930,868
Current maturities of long-term debt	(60,000)	(50,000)
Total long-term debt	$ 923,910	$ 880,868

(a) Humboldt County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total of first mortgage
bonds outstanding at December 31, 2004 to $834.8 million.

At December 31, 2004, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2005	2006	2007	2008	2009	Thereafter
IPC	$ 60,000	$ -	$ 81,064	$ 1,064	$ 81,064	$ 760,718

On October 22, 2003, Humboldt County, Nevada issued, for the benefit of IPC, $49.8 million Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 due December 1, 2024. IPC borrowed the proceeds from the issuance pursuant to a

Loan Agreement with Humboldt County and is responsible for payment of principal, premium, if any, and interest on the bonds. The bonds are secured, as to principal and interest, by IPC first mortgage bonds and as to principal and interest when due, by an insurance policy issued by Ambac Assurance Corporation. The bonds were issued in an auction rate mode under which the interest rate is reset every 35 days. The initial auction rate was set at 0.95 percent. At December 31, 2004, the auction rate was 1.85 percent. Proceeds from this issuance together with other funds provided by IPC were used to redeem the outstanding $49.8 million Pollution Control Revenue Bonds (Idaho Power Company Project) 8.3% Series 1984 due 2014, on December 1, 2003, at 103 percent.

On March 14, 2003, IPC filed a $300 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes), unsecured debt and preferred stock. On May 8, 2003, IPC issued $140 million of secured medium-term notes in two series: $70 million First Mortgage Bonds 4.25% Series due 2013 and $70 million First Mortgage Bonds 5.50% Series due 2033. Proceeds were used to pay down IPC short-term borrowings incurred from the payment at maturity of $80 million First Mortgage Bonds 6.40% Series due 2003 and the early redemption of $80 million First Mortgage Bonds 7.50% Series due 2023, on May 1, 2003. On March 26, 2004, IPC issued $50 million First Mortgage Bonds 5.50% Series due 2034. Proceeds were used to reduce short-term borrowings and replace short-term investments, which were used on March 15, 2004 to pay at maturity the $50 million First Mortgage Bonds 8% Series due 2004. On August 16, 2004, IPC issued $55 million First Mortgage Bonds 5.875% Series due 2034. On September 20, 2004, the proceeds of this issuance were used to redeem all of IPC's outstanding preferred stock. At December 31, 2004, $55 million remained available to be issued on this shelf registration statement.

On January 19, 2005, IPC filed a $245 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes) and debt securities.

On August 17, 2004, IPC redeemed all $1 million of its Rural Electrification Administration notes.

At December 31, 2004 and 2003, the overall effective cost of all of IPC's outstanding debt was 5.69 percent and 5.71 percent, respectively.

The amount of first mortgage bonds issuable by IPC is limited to a maximum of $1.1 billion and by property, earnings and other provisions of the mortgage and supplemental indentures thereto. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. Substantially all of the electric utility plant is subject to the lien of the mortgage. As of December 31, 2004, IPC could issue under the mortgage approximately $699 million of additional first mortgage bonds based on unfunded property additions and $392 million of additional first mortgage bonds based on retired first mortgage bonds. At December 31, 2004, unfunded property additions, which consist of electric property, were approximately $1.1 billion.

6. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The estimated fair value of IPC's financial instruments has been determined using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Cash and cash equivalents, customer and other receivables, notes payable, accounts payable, interest accrued and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable, long-term debt and investments is based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2004		December 31, 2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Assets:				
Notes receivable	$ 8,946	$ 8,877	$ 10,145	$ 10,159
Investments	53,155	53,155	22,438	22,438
Liabilities:				
Long-term debt	$ 987,045	$ 1,008,369	$ 933,150	$ 957,399

7. NOTES PAYABLE:

At December 31, 2004, IPC had regulatory authority to incur up to $250 million of short-term indebtedness. IPC has a $200 million credit facility that expires on March 16, 2007. Under this facility IPC pays a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's and S&P. IPC's commercial paper may be issued up to the amounts supported by the bank credit facilities. There was no commercial paper outstanding at December 31, 2004 or 2003.

8. COMMITMENTS AND CONTINGENCIES:

As of December 31, 2004, IPC had agreements to purchase energy from 71 cogeneration and small power production (CSPP) facilities with contracts ranging from one to 30 years. Under these contracts IPC is required to purchase all of the output from the facilities inside the IPC service territory. For projects outside the IPC service territory, IPC is required to purchase the output which IPC has the ability to receive at the facility's requested point of delivery on the IPC system. IPC purchased 677,868 megawatt-hours (MWh) at a cost of $40 million in 2004 and 654,131 MWh at a cost of $38 million in 2003.

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2004. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs and expects that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

From time to time IPC is a party to various legal claims, actions and complaints in addition to those discussed below. IPC believes that it has meritorious defenses to all lawsuits and legal proceedings. Although it will vigorously defend against them, it is unable to predict with certainty whether or not it will ultimately be successful. However, based on the company's evaluation, it believes that the resolution of these matters will not have a material adverse effect on IPC's financial positions, results of operations or cash flows.

Legal Proceedings

Alves Dairy: On May 18, 2004, Herculano and Frances Alves, dairy operators from Twin Falls, Idaho, brought suit against IPC in Idaho State District Court, Fifth Judicial District, Twin Falls County. The plaintiffs seek unspecified monetary damages for negligence and nuisance (allegedly allowing electrical current to flow in the earth, injuring the plaintiffs' right to use and enjoy their property and adversely affecting their dairy herd). On July 16, 2004, IPC filed an answer to Mr. and Mrs. Alves' complaint, denying all liability to the plaintiffs, and asserting certain affirmative defenses. The parties have begun discovery in the case. No trial date has been scheduled. On December 14, 2004, IPC filed a motion with the District Court for permission to appeal the court's denial of IPC's Motion to Disqualify the trial judge, for cause. The District Court granted the motion for permissive appeal. On February 16, 2005, IPC filed a motion for permissive appeal with the Idaho Supreme Court. If granted, the Supreme Court will determine whether the District Court properly refused to disqualify the trial judge for cause.

IPC intends to vigorously defend its position in this proceeding and believes this matter, with insurance coverage, will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Public Utility District No. 1 of Grays Harbor County, Washington: On October 15, 2002, Public Utility District No. 1 of Grays Harbor County, Washington (Grays Harbor) filed a lawsuit in the Superior Court of the State of Washington, for the County of Grays Harbor, against IDACORP, IPC and IE. On March 9, 2001, Grays Harbor entered into a 20 Megawatt (MW) purchase transaction with IPC for the purchase of electric power from October 1, 2001 through March 31, 2002, at a rate of $249 per MWh. In June 2001, with the consent of Grays Harbor, IPC assigned all of its rights and obligations under the contract to IE. In its lawsuit, Grays Harbor alleged that the assignment was void and unenforceable, and sought restitution from IE and IDACORP, or in the alternative, Grays Harbor alleged that the contract should be rescinded or reformed. Grays Harbor sought as damages an amount equal to the difference between $249 per MWh and the "fair value" of electric power delivered by IE during the period October 1, 2001 through March 31, 2002.

IDACORP, IPC and IE had this action removed from the state court to the U.S. District Court for the Western District of Washington at Tacoma. On November 12, 2002, the companies filed a motion to dismiss Grays Harbor's complaint, asserting that the U.S. District Court lacked jurisdiction because the FERC has exclusive jurisdiction over wholesale power transactions and thus the matter is preempted under the Federal Power Act and barred by the filed-rate doctrine. The court ruled in favor of the companies' motion to dismiss and dismissed the case with prejudice on January 28, 2003. On February 25, 2003, Grays Harbor filed a Notice of Appeal, appealing the final judgment of dismissal to the U.S. Court of Appeals for the Ninth Circuit. On August 10, 2004, the Ninth Circuit affirmed the dismissal of Grays Harbor's complaint, finding that Grays Harbor's claims were preempted by federal law and were barred by the filed-rate doctrine. The court also remanded the case to allow Grays Harbor leave to amend its complaint to seek declaratory relief only as to contract formation, and held that Grays Harbor could seek monetary relief, if at all, only from the FERC, and not from the courts. IDACORP, IPC and IE sought rehearing from the Ninth Circuit arguing that the court erred in granting leave to amend the complaint as such a declaratory relief claim would be preempted and would be barred by the filed-rate doctrine. The Ninth Circuit denied the rehearing request on October 25, 2004 and the decision became final on November 12, 2004. On that same date, the companies took steps to have the case transferred and consolidated with other similar cases arising out the California energy crisis currently pending before the Honorable Robert H. Whaley, sitting by designation in the Southern District of California and presiding over Multidistrict Litigation Docket No. 1405, regarding California Wholesale Electricity Antitrust Litigation. On November 18, 2004, Grays Harbor filed an amended complaint alleging that the contract was formed under circumstances of "mistake" as to an "artificial . . . power shortage." Grays Harbor asks that the contract therefore be declared "unenforceable" and found "unconscionable." On December 23, 2004, the Judicial Panel on Multidistrict Litigation conditionally transferred the case to Judge Whaley. Grays Harbor is opposing transfer, however, and the Judicial Panel on Multidistrict Litigation has yet to finally rule on the transfer. IDACORP, IE and IPC have not responded to the amended complaint as a response is not yet required. The companies plan to file a motion to dismiss the complaint. The companies intend to vigorously defend their position on remand and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Port of Seattle: On May 21, 2003, the Port of Seattle, a Washington municipal corporation, filed a lawsuit against 20 energy firms, including IPC and IDACORP, in the U.S. District Court for the Western District of Washington at Seattle. The Port of Seattle's complaint alleges fraud and violations of state and federal antitrust laws and the Racketeer Influenced and Corrupt Organizations Act. On December 4, 2003, the Judicial Panel on Multidistrict Litigation transferred the case to the Southern District of California for inclusion with several similar multidistrict actions currently pending before the Honorable Robert H. Whaley.

All defendants, including IPC and IDACORP, moved to dismiss the complaint in lieu of answering it. The motions were based on the ground that the complaint seeks to set alternative electrical rates, which are exclusively within the jurisdiction of the FERC and are barred by the filed-rate doctrine. A hearing on the motion to dismiss was heard on March 26, 2004. On May 28, 2004, the court granted IPC and IDACORP's motion to dismiss. In June 2004, the Port of Seattle appealed the court's decision to the U.S. Court of Appeals for the Ninth Circuit. The appeal has been fully briefed, however no date has yet been set for oral argument. The companies intend to vigorously defend their position in this proceeding and believe these matters will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Wah Chang: On May 5, 2004, Wah Chang, a division of TDY Industries, Inc., filed two lawsuits in the U.S. District Court for the District of Oregon against numerous defendants. IDACORP, IE and IPC are named as defendants in one of the lawsuits. The complaints allege violations of federal antitrust laws, violations of the Racketeer Influenced and Corrupt Organizations Act, violations of Oregon antitrust laws and wrongful interference with contracts. Wah Chang's complaint is based on allegations relating to the western energy situation. These allegations include bid rigging, falsely creating congestion and misrepresenting the source and destination of energy. The plaintiff seeks compensatory damages of $30 million and treble damages.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley, sitting by designation in the Southern District of California and presiding over Multidistrict Litigation Docket No. 1405, regarding California Wholesale Electricity Antitrust Litigation. IDACORP, IE and IPC have not answered the complaint, as a response is not yet required. The companies, along with the other defendants, subsequently filed a motion to dismiss the complaint, which was heard on January 20, 2005. By order dated February 11, 2005, the court granted the companies' and other defendants' motion to dismiss. The companies intend to vigorously defend their position in this proceeding and believe these matters will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

City of Tacoma: On June 7, 2004, the City of Tacoma, Washington filed a lawsuit in the U.S. District Court for the Western District of Washington at Tacoma against numerous defendants including IDACORP, IE and IPC. The City of Tacoma's complaint alleges violations of the Sherman Antitrust Act. The claimed antitrust violations are based on allegations of energy market manipulation, false load scheduling and bid rigging and misrepresentation or withholding of energy supply. The plaintiff seeks compensatory damages of not less than $175 million.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley, sitting by designation in the Southern District of California and presiding over Multidistrict Litigation Docket No. 1405, regarding California Wholesale Electricity Antitrust Litigation. IDACORP, IE and IPC have not answered the complaint, as a response is not yet required. The companies, along with the other defendants, filed a motion to dismiss the complaint which was taken under submission by the court, without oral argument. By order dated February 11, 2005, the court granted the companies' and other defendants' motion to dismiss. The companies intend to vigorously defend their position in this proceeding and believe these matters will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

State of California Attorney General: The California Attorney General filed the complaint in this case in the California Superior Court in San Francisco on May 30, 2002. This is one of thirteen virtually identical cases brought by the Attorney General against various sellers of power in the California market, seeking civil penalties pursuant to California's Unfair Competition Law, Business and Professions Code Section 17200. Section 17200 defines unfair competition as any "unlawful, unfair or fraudulent business act or practice . . . ." The Attorney General alleges that IPC engaged in unlawful conduct by violating the Federal Power Act in two respects: (1) by failing to file its rates with the FERC and (2) charging unjust and unreasonable rates. The Attorney General alleged that there were "thousands of . . . sales or purchases" for which IPC failed to file its rates, and that IPC charged unjust and unreasonable rates on "thousands of occasions." Pursuant to Business and Professions Code Section 17206, the Attorney General seeks civil penalties of up to $2,500 for each alleged violation. On June 25, 2002, IPC removed the action to federal court, and on July 25, 2002, the Attorney General filed a motion to remand back to state court. On March 25, 2003, the court denied the Attorney General's motion to remand and granted IPC's motion to dismiss the case based upon grounds of federal preemption and the filed-rate doctrine. On March 28, 2003, the Attorney General filed a Notice of Appeal to the U.S. Court of Appeals for the Ninth Circuit, appealing the court's decision granting IPC's motion to dismiss. Briefing on the appeal was completed in October 2003. On October 12, 2004, the Ninth Circuit unanimously affirmed the order denying remand and dismissing all of the Attorney General's actions, including the action against IPC. The Attorney General did not file a petition for rehearing in the Ninth Circuit and has not sought review from the U.S. Supreme Court. As a result, the Ninth Circuit's October 12, 2004 decision is final.

Wholesale Electricity Antitrust Cases I & II: These cross-actions against IE and IPC emerged from multiple California state court proceedings first initiated in late 2000 against various power generators/marketers by various California municipalities and citizens. Suit was filed against entities including Reliant Energy Services, Inc., Reliant Ormond Beach, L.L.C., Reliant Energy Etiwanda, L.L.C., Reliant Energy Ellwood, L.L.C., Reliant Energy Mandalay, L.L.C. and Reliant Energy Coolwater, L.L.C. (collectively, Reliant); and Duke Energy Trading and Marketing, L.L.C., Duke Energy Morro Bay, L.L.C., Duke Energy Moss Landing, L.L.C., Duke Energy South Bay, L.L.C. and Duke Energy Oakland, L.L.C. (collectively, Duke). While varying in some particulars, these cases made a common claim that Reliant, Duke and certain others (not including IE or IPC) colluded to influence the price of electricity in the California wholesale electricity market. Plaintiffs asserted various claims that the defendants violated the California Antitrust Law (the Cartwright Act), Business and Professions Code Section 16720 and California's Unfair Competition Law, Business and Professions Code Section 17200. Among the acts complained of are bid rigging, information exchanges, withholding of power and other wrongful acts. These actions were subsequently consolidated, resulting in the filing of Plaintiffs' Master Complaint in San Diego Superior Court on March 8, 2002.

On April 22, 2002, more than a year after the initial complaints were filed, two of the original defendants, Duke and Reliant, filed separate cross-complaints against IPC and IE, and approximately 30 other cross-defendants. Duke and Reliant's cross-complaints seek indemnity from IPC, IE and the other cross-defendants for an unspecified share of any amounts they must pay in the underlying suits because, they allege, other market participants like IPC and IE engaged in the same conduct at issue in the Plaintiffs' Master Complaint. Duke and Reliant also seek declaratory relief as to the respective liability and conduct of each of the cross-defendants in the actions alleged in the Plaintiffs' Master Complaint. Reliant also asserted a claim against IPC for alleged violations of the California Unfair Competition Law, Business and Professions Code Section 17200. As a buyer of electricity in California, Reliant seeks the same relief from the cross-defendants, including IPC, as that sought by plaintiffs in the Plaintiffs' Master Complaint as to any power Reliant purchased through the California markets.

Some of the newly added defendants (foreign citizens and federal agencies) removed that litigation to federal court. IPC and IE, together with numerous other defendants added by the cross-complaints, have moved to dismiss these claims, and those motions were heard in September 2002, together with motions to remand the case back to state court filed by the original plaintiffs. On December 13, 2002, the U.S. District Court granted Plaintiffs' Motion to Remand to state court, but did not issue a ruling on IPC and IE's motion to dismiss. The U.S. Court of Appeals for the Ninth Circuit granted certain Defendants and Cross-Defendants' Motions to Stay the Remand Order while they appeal the order. The briefing on the appeal was completed in December 2003. On December 8, 2004, the Ninth Circuit issued its opinion in California v. NRG Energy, Inc., et al., which affirmed the district court's remand of these cases to state court and dismissed certain federal government defendants due to their sovereign immunity from suit. Cross-defendant, Powerex Corp., sought Rehearing En Banc at the Ninth Circuit arguing that while it is a government entity, it is not immune from suit but should be permitted to litigate in federal rather than state court. If the case is returned to state court, the companies, and other cross-defendants, intend to re-file their motions to dismiss in state court, which had been filed in federal court but never ruled upon. The companies believe these matters will not have a material adverse effect on their consolidated financial positions, results of operations or cash flow.

Western Energy Proceedings at the FERC:

California Power Exchange Chargeback:

As a component of IPC's non-utility energy trading in the State of California, IPC, in January 1999, entered into a participation agreement with the California Power Exchange (CalPX), a California non-profit public benefit corporation. The CalPX, at that time, operated a wholesale electricity market in California by acting as a clearinghouse through which electricity was bought and sold. Pursuant to the participation agreement, IPC could sell power to the CalPX under the terms and conditions of the CalPX Tariff. Under the participation agreement, if a participant in the CalPX defaulted on a payment, the other participants were required to pay their allocated share of the default amount to the CalPX. The allocated shares were based upon the level of trading activity, which included both power sales and purchases, of each participant during the preceding three-month period.

On January 18, 2001, the CalPX sent IPC an invoice for $2 million - a "default share invoice" - as a result of an alleged Southern California Edison payment default of $215 million for power purchases. IPC made this payment. On January 24, 2001, IPC terminated its participation agreement with the CalPX. On February 8, 2001, the CalPX sent a further invoice for $5 million, due on February 20, 2001, as a result of alleged payment defaults by Southern California Edison, Pacific Gas and Electric Company and others. However, because the CalPX owed IPC $11 million for power sold to the CalPX in November and December 2000, IPC did not pay the February 8 invoice. The CalPX later reversed IPC's payment of the January 18, 2001 invoice, but on June 20, 2001 invoiced IPC for an additional $2 million which the CalPX has not reversed. The CalPX owes IPC $14 million for power sold in November and December including $2 million associated with the default share invoice dated June 20, 2001. IPC essentially discontinued energy trading with the CalPX and the California Independent System Operator (Cal ISO) in December 2000.

IPC believes that the default invoices were not proper and that IPC owes no further amounts to the CalPX. IPC has pursued all available remedies in its efforts to collect amounts owed to it by the CalPX. On February 20, 2001, IPC filed a petition with the FERC to intervene in a proceeding that requested the FERC to suspend the use of the CalPX chargeback methodology and provide for further oversight in the CalPX's implementation of its default mitigation procedures.

A preliminary injunction was granted by a federal judge in the U.S. District Court for the Central District of California enjoining the CalPX from declaring any CalPX participant in default under the terms of the CalPX Tariff. On March 9, 2001, the CalPX filed for Chapter 11 protection with the U.S. Bankruptcy Court, Central District of California.

In April 2001, Pacific Gas and Electric Company filed for bankruptcy. The CalPX and the Cal ISO were among the creditors of Pacific Gas and Electric Company. To the extent that Pacific Gas and Electric Company's bankruptcy filing affects the collectibility of the receivables from the CalPX and the Cal ISO, the receivables from these entities are at greater risk.

The FERC issued an order on April 6, 2001 requiring the CalPX to rescind all chargeback actions related to Pacific Gas and Electric Company's and Southern California Edison's liabilities. Shortly after the issuance of that order, the CalPX segregated the CalPX chargeback amounts it had collected in a separate account. The CalPX claims it is awaiting further orders from the FERC and the bankruptcy court before distributing the funds that it collected under its chargeback tariff mechanism. Although certain parties to the California refund proceeding urged the FERC's Presiding Administrative Law Judge to consider the chargeback amounts in his determination of who owes what to whom, in his Certification of Proposed Findings on California Refund Liability, he concluded that the matter already was pending before the FERC for disposition. On October 7, 2004, the FERC issued an order determining that it would not require the disbursement of chargeback funds until the completion of the California refund proceedings. On November 8, 2004, IE, along with a number of other parties, sought rehearing of that order. The FERC has not yet acted on the requests for rehearing.

California Refund:

In April 2001, the FERC issued an order stating that it was establishing price mitigation for sales in the California wholesale electricity market. Subsequently, in a June 19, 2001 order, the FERC expanded that price mitigation plan to the entire western United States electrically interconnected system. That plan included the potential for orders directing electricity sellers into California since October 2, 2000 to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable, and therefore not in compliance with the Federal Power Act. The June 19 order also required all buyers and sellers in the Cal ISO market during the subject time frame to participate in settlement discussions to explore the potential for resolution of these issues without further FERC action. The settlement discussions failed to bring resolution of the refund issue and as a result, the FERC's Chief Administrative Law Judge submitted a Report and Recommendation to the FERC recommending that the FERC adopt the methodology set forth in the report and set for evidentiary hearing an analysis of the Cal ISO's and the CalPX's spot markets to determine what refunds may be due upon application of that methodology.

On July 25, 2001, the FERC issued an order establishing evidentiary hearing procedures related to the scope and methodology for calculating refunds related to transactions in the spot markets operated by the Cal ISO and the CalPX during the period October 2, 2000 through June 20, 2001 (Refund Period).

This case had been complicated by an August 13, 2002 FERC Staff Report which included the recommendation to replace the published California indices for gas prices that the FERC previously established as just and reasonable for calculating a Mitigated Market Clearing Price to calculate refunds with other published indices for producing basin prices plus a transportation allowance. The FERC Staff's recommendation is grounded on speculation that some sellers had an incentive to report exaggerated prices to publishers of the indices, resulting in overstated published index prices. The FERC Staff based its speculation in large part on a statistical correlation analysis of Henry Hub and California prices. IE, in conjunction with others, submitted comments on the FERC Staff recommendation - asserting that the staff's conclusions were incorrect because the staff's correlation study ignored evidence of normal market forces and scarcity that created the pricing variations that the staff observed, rather than improper manipulation of reported prices.

The Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability on December 12, 2002.

The FERC issued its Order on Proposed Findings on Refund Liability on March 26, 2003. In large part, the FERC affirmed the recommendations of its Administrative Law Judge. However, the FERC changed a component of the formula the Administrative Law Judge was to apply when it adopted findings of its staff that published California spot market prices for gas did not reliably reflect the prices a gas market that had not been manipulated would have produced, despite the fact that many gas buyers paid those amounts. The findings of the Administrative Law Judge, as adjusted by the FERC's March 26, 2003 order, are expected to increase the offsets to amounts still owed by the Cal ISO and the CalPX to the companies. Calculations remain uncertain because the FERC has required the Cal ISO to correct a number of defects in its calculations and because the FERC has stated that if refunds will prevent a seller from recovering its California portfolio costs during the Refund Period, it will provide an opportunity for a cost showing by such a respondent. As a result, IE is unsure of the impact this ruling will have on the refunds due from California. However, as to potential refunds, if any, IE believes its exposure is likely to be offset by amounts due from California entities.

IE, along with a number of other parties, filed an application with the FERC on April 25, 2003 seeking rehearing of the March 26, 2003 order. On October 16, 2003, the FERC issued two orders denying rehearing of most contentions that had been advanced and directing the Cal ISO to prepare its compliance filing calculating revised Mitigated Market Clearing Prices and refund amounts within five months. The Cal ISO has since requested additional time to complete its compliance filings. By order of February 3, 2004, the FERC granted additional time. In a February 10, 2004 report to the FERC, the Cal ISO asserted its belief that it would complete re-running the data and financial clearing of amounts due by August 2004, subject to a number of events that must occur in the interim, including FERC disposition of a number of pending issues. This Cal ISO compliance filing has since been delayed until at least April 2005. The Cal ISO is required to update the FERC on its progress monthly. After receipt of the compliance filing, the FERC will consider cost-based filings from sellers to reduce their refund exposure.

On December 2, 2003, IE petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC's orders, and since that time, dozens of other petitions for review have been filed. The Ninth Circuit consolidated IE's and the other parties' petitions with the petitions for review arising from earlier FERC orders in this proceeding, bringing the total number of consolidated petitions to more than 100. The Ninth Circuit held the appeals in abeyance pending the disposition of the market manipulation claims discussed below and the development of a comprehensive plan to brief this complicated case. Certain parties also sought further rehearing and clarification before the FERC. On September 21, 2004, the Ninth Circuit convened case management proceedings, a procedure reserved to help organize complex cases. On October 22, 2004, the Ninth Circuit severed a subset of the stayed appeals in order that briefing could commence regarding limited issues of: (1) which parties are subject to the FERC's refund jurisdiction under section 201(f) of the Federal Power Act; (2) the temporal scope of refunds under section 206 of the Federal Power Act; and (3) which categories of transactions are subject to refunds. Petitioners and petitioner-intervenors, including IE, filed opening briefs regarding the latter two issues on December 23, 2004. The FERC filed its respondent's brief on January 31, 2005, and petitioners and petitioner-intervenors, including IE, filed their reply briefs on March 1, 2005. Oral argument is scheduled for April 12-13, 2005.

On May 12, 2004, the FERC issued an order clarifying portions of its earlier refund orders and, among other things, denying a proposal made by Duke Energy North America and Duke Energy Trading and Marketing (and supported by IE) to lodge as evidence a contested settlement in a separate complaint proceeding, California Public Utilities Commission (CPUC) v. El Paso et al. The CPUC's complaint alleged that the El Paso companies manipulated California energy markets by withholding pipeline transportation capacity into California in order to drive up natural gas prices immediately before and during the California energy crisis in 2000-2001. The settlement will result in the payment by El Paso of some $1.69 billion. Duke claimed that the relief afforded by the settlement was duplicative of the remedies imposed by the FERC in its March 26, 2003 order changing the gas cost component of its refund calculation methodology. IE, along with other parties, has sought rehearing of the May 12, 2004 order. On November 23, 2004, the FERC denied rehearing and within the statutory time allowed for petitions, a number of parties, including IE, filed petitions for review of the FERC's order. These petitions have since been consolidated with the larger number of review petitions in connection with the California refund proceeding.

In June 2001, IPC transferred its non-utility wholesale electricity marketing operations to IE. Effective with this transfer, the outstanding receivables and payables with the CalPX and the Cal ISO were assigned from IPC to IE. At December 31, 2004, with respect to the CalPX chargeback and the California refund proceedings discussed above, the CalPX and the Cal ISO owed $14 million and $30 million, respectively, for energy sales made to them by IPC in November and December 2000. IE has accrued a reserve of $42 million against these receivables. This reserve was calculated taking into account the uncertainty of collection given the California energy situation. Based on the reserve recorded as of December 31, 2004, IDACORP believes that the future collectibility of these receivables or any potential refunds ordered by the FERC would not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, including IE and IPC, alleging that the FERC's market-based rate requirements violate the Federal Power Act, and, even if the market-based rate requirements are valid, that the quarterly transaction reports filed by sellers do not contain the transaction-specific information mandated by the Federal Power Act and the FERC. The complaint stated that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including IE and IPC, to refile their quarterly reports to include transaction-specific data. The Attorney General appealed the FERC's decision to the U.S. Court of Appeals for the Ninth Circuit. The Attorney General contends that the failure of all market-based rate authority sellers of power to have rates on file with the FERC in advance of sales is impermissible. The Ninth Circuit issued its decision on September 9, 2004, concluding that market-based tariffs are permissible under the Federal Power Act, but remanded the matter to the FERC to consider whether the FERC should exercise remedial power (including some form of refunds) when a market participant failed to submit reports that the FERC relies on to confirm the justness and reasonableness of rates charged. Certain parties to the litigation have sought rehearing. The companies cannot predict whether rehearing will be granted or what action the FERC might take if the matter is remanded.

Market Manipulation:
In a November 20, 2002 order, the FERC permitted discovery and the submission of evidence respecting market manipulation by various sellers during the western power crises of 2000 and 2001.

On March 3, 2003, the California Parties (certain investor owned utilities, the California Attorney General, the California Electricity Oversight Board and the CPUC) filed voluminous documentation asserting that a number of wholesale power suppliers, including IE and IPC, had engaged in a variety of forms of conduct that the California Parties contended were impermissible. Although the contentions of the California Parties were contained in more than 11 compact discs of data and testimony, approximately 12,000 pages, IE and IPC were mentioned in limited contexts with the overwhelming majority of the claims of the California Parties relating to the conduct of other parties.

The California Parties urged the FERC to apply the precepts of its earlier decision, to replace actual prices charged in every hour starting May 1, 2000 through the beginning of the existing Refund Period with a Mitigated Market Clearing Price, seeking approximately $8 billion in refunds to the Cal ISO and the CalPX. On March 20, 2003, numerous parties, including IE and IPC, submitted briefs and responsive testimony.

In its March 26, 2003 order, discussed above in "California Refund," the FERC declined to generically apply its refund determinations to sales by all market participants, although it stated that it reserved the right to provide remedies for the market against parties shown to have engaged in proscribed conduct.

On June 25, 2003, the FERC ordered over 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior in violation of the Cal ISO and the CalPX Tariffs. The Cal ISO was ordered to provide data on each entity's trading practices within 21 days of the order, and each entity was to respond explaining their trading practices within 45 days of receipt of the Cal ISO data. IPC submitted its responses to the show cause orders on September 2 and 4, 2003. On October 16, 2003, IPC reached agreement with the FERC Staff on the two orders commonly referred to as the "gaming" and "partnership" show cause orders. Regarding the gaming order, the FERC Staff determined it had no basis to proceed with allegations of false imports and paper trading and IPC agreed to pay $83,373 to settle allegations of circular scheduling. IPC believed that it had defenses to the circular scheduling allegation but determined that the cost of settlement was less than the cost of litigation. In the settlement, IPC did not admit any wrongdoing or violation of any law. With respect to the "partnership" order, the FERC Staff submitted a motion to the FERC to dismiss the proceeding because materials submitted by IPC demonstrated that IPC did not use its "parking" and "lending" arrangement with Public Service Company of New Mexico to engage in "gaming" or anomalous market behavior ("partnership"). The "gaming" settlement was approved by the FERC on March 3, 2004. Eight parties have requested rehearing of the FERC's March 3, 2004 order, but the FERC has not yet acted on those requests. The motion to dismiss the "partnership" proceeding was approved by the FERC in an order issued on January 23, 2004 and rehearing of that order was not sought within the time allowed by statute. Some of the California Parties and other parties have petitioned the U.S. Court of Appeals for the Ninth Circuit and the District of Columbia Circuit for review of the FERC's orders initiating the show cause proceedings. Some of the parties contend that the scope of the proceedings initiated by the FERC was too narrow. Other parties contend that the orders initiating the show cause proceedings were impermissible. Under the rules for multidistrict litigation, a lottery was held and although these cases were to be considered in the District of Columbia Circuit by order of February 10, 2005, the District of Columbia Circuit transferred the proceedings to the Ninth Circuit. The FERC had moved the District of Columbia Circuit to dismiss these petitions on the grounds of prematurity and lack of ripeness and finality. The transfer order was issued before a ruling from the District of Columbia Circuit and the motions, if renewed, will be considered by the Ninth Circuit. The company is not able to predict the outcome of the judicial determination of these issues.

On June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale power markets. In this investigation, the FERC was to review evidence of alleged economic withholding of generation. The FERC determined that all bids into the CalPX and the Cal ISO markets for more than $250 per MWh for the time period May 1, 2000 through October 1, 2000 would be considered prima facie evidence of economic withholding. The FERC Staff issued data requests in this investigation to over 60 market participants including IPC. IPC responded to the FERC's data requests. In a letter dated May 12, 2004, the FERC's Office of Market Oversight and Investigations advised that it was terminating the investigation as to IPC.

<u>Pacific Northwest Refund</u>:

On July 25, 2001, the FERC issued an order establishing another proceeding to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001. The FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001. The Administrative Law Judge found that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that no refunds should be allowed. Procedurally, the Administrative Law Judge's decision is a recommendation to the commissioners of the FERC. Multiple parties submitted comments to the FERC with respect to the Administrative Law Judge's recommendations. The Administrative Law Judge's recommended findings had been pending before the FERC, when at the request of the City of Tacoma and the Port of Seattle on December 19, 2002, the FERC reopened the proceedings to allow the submission of additional evidence related to alleged manipulation of the power market by Enron and others. As was the case in the California refund proceeding, at the conclusion of the discovery period, parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. Grays Harbor, whose civil litigation claims were dismissed, as noted above, intervened in this FERC proceeding, asserting on March 3, 2003 that its six-month forward contract, for which performance has been completed, should be treated as a spot market contract for purposes of the FERC's consideration of refunds and is requesting refunds from IPC of $5 million. Grays Harbor did not suggest that there was any misconduct by IPC or IE. The companies submitted responsive testimony defending vigorously against Grays Harbor's refund claims.

In addition, the Port of Seattle, the City of Tacoma and the City of Seattle made filings with the FERC on March 3, 2003 claiming that because some market participants drove prices up throughout the west through acts of manipulation, prices for contracts throughout the Pacific Northwest market should be re-set starting in May 2000 using the same factors the FERC would use for California markets. Although the majority of the claims of these parties are generic, they named a number of power market suppliers, including IPC and IE, as having used parking services provided by other parties under FERC-approved tariffs and thus as being candidates for claims of improperly having received congestion revenues from the Cal ISO. On June 25, 2003, after having considered oral argument held earlier in the month, the FERC issued its Order Granting Rehearing, Denying Request to Withdraw Complaint and Terminating Proceeding, in which it terminated the proceeding and denied claims that refunds should be paid. The FERC denied rehearing on November 10, 2003, triggering the right to file for review. The Port of Seattle, the City of Tacoma, the City of Seattle, the California Attorney General, the CPUC and Puget Sound Energy Inc. filed petitions for review in the Ninth Circuit. These petitions have been consolidated. Grays Harbor did not file a petition for review, although it has sought to intervene in the proceedings initiated by the petitions of others. The FERC has certified the record to the Ninth Circuit. On July 21, 2004, the City of Seattle submitted to the Ninth Circuit in the Pacific Northwest refund petition for review a motion requesting leave to offer additional evidence before the FERC in order to try to secure another opportunity for reconsideration by the FERC of its earlier rulings. The evidence that the City of Seattle seeks to introduce before the FERC consists of audio tapes of what purports to be Enron trader conversations containing inflammatory language that have been the subject of coverage in the press. Under Section 313(b) of the Federal Power Act, a court is empowered to direct the introduction of additional evidence if it is material and could not have been introduced during the underlying proceeding. The City of Seattle also requested that the current briefing schedule, which required briefs to be filed by August 5, 2004, be delayed. On September 29, 2004, the Ninth Circuit denied the City of Seattle's motion for leave to adduce evidence, without prejudice to renewing the request for remand in the briefing in the Pacific Northwest refund case. Petitioner's briefs were filed January 14, 2005, Petitioner-intervenors briefs were filed on February 14, 2005 and Respondent's brief is due March 30, 2005 and Respondent-intervenor's briefs and the briefs of any non-aligned intevenors are due April 29, 2005. Petitioners reply briefs are due 42 days after service of respondent's briefs. Petitioner-intervenors' briefs are due 56 days after service of respondent's briefs. A date for oral argument has not yet been set.

The companies are unable to predict the outcome of these matters.

On July 21, 2004, Californians for Renewable Energy, Inc. (CARE) filed a motion with the FERC in connection with the California Refund proceedings, the Pacific Northwest refund proceedings and the show cause proceedings, both gaming and partnership, including those in which IPC was the respondent. CARE has participated in many of the FERC proceedings dealing with California energy matters, having appointed itself as a representative of low-income communities and other groups that it claims are otherwise not represented. The FERC permitted CARE to participate in the cases as an intervenor. In its current motion, CARE requests that the FERC radically restructure its approach to California and western energy proceedings involving the events of 2000 and 2001 by revoking market-based rate authority from the date of their approvals, replacing market-based rates with cost-of-service rates by requiring refunds back to the date of the orders granting market-based rate authority, revising long-term energy contracts negotiated during 2000 and 2001 (it appears that the contracts that CARE identified do not include any to which IPC is a party), deferring further refund settlements, establishing a direct pass-through refund mechanism for California consumers and having "previously executed settlement agreements rejected." CARE also requested that the FERC revoke market-based rates for those entities identified in the June 25, 2003 show cause orders, which would include IPC. IPC defended itself in response to this motion and is unable to predict how the FERC will respond to CARE's motion. On September 9, 2004, CARE filed a motion to withdraw its July 21, 2004 pleading. By operation of law, the withdrawal was effective September 24, 2004.

Shareholder Lawsuits: On May 26, 2004 and June 22, 2004, respectively, two shareholder lawsuits were filed against IDACORP and certain of its directors and officers. The lawsuits, captioned Powell, et al. v. IDACORP, Inc., et al. and Shorthouse, et al. v. IDACORP, Inc., et al., raise largely similar allegations. The lawsuits are putative class actions brought on behalf of purchasers of IDACORP stock between February 1, 2002 and June 4, 2002, and were filed in the U.S. District Court for the District of Idaho. The named defendants in each suit, in addition to IDACORP, are Jon H. Miller, Jan B. Packwood, J. LaMont Keen and Darrel T. Anderson.

The complaints alleged that, during the purported class period, IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about the company's financial outlook in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended, and Rule 10b-5, thereby causing investors to purchase the company's common stock at artificially inflated prices. More specifically, the complaints alleged that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to defendants or recklessly disregarded by them: (1) IDACORP failed to appreciate the negative impact that lower volatility and reduced pricing spreads in the western wholesale energy market would have on its marketing subsidiary, IE; (2) IDACORP would be forced to limit its origination activities to shorter-term transactions due to increasing regulatory uncertainty and continued deterioration of creditworthy counterparties; (3) IDACORP failed to discount for the fact that IPC may not recover from the lingering effects of the prior year's regional drought and (4) as a result of the foregoing, defendants lacked a reasonable basis for their positive statements about IDACORP and their earnings projections. The Powell complaint also alleged that the defendants' conduct artificially inflated the price of the company's common stock. The actions seek an unspecified amount of damages, as well as other forms of relief. By order dated August 31, 2004, the court consolidated the Powell and Shorthouse cases for pretrial purposes, and ordered the plaintiffs to file a consolidated complaint within 60 days. On November 1, 2004, IDACORP and the directors and officers named above were served with a purported consolidated complaint captioned Powell et al. v. IDACORP, Inc. et al., which was filed in the U.S. District Court for the District of Idaho.

The new complaint alleges that during the class period IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about its business operations, and specifically the IDACORP Energy financial outlook, in violation of Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. The new complaint alleges that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to it or recklessly disregarded by it: (1) IDACORP falsely inflated the value of energy contracts held by IDACORP Energy in order to report higher revenues and profits; (2)

IDACORP permitted IPC to inappropriately grant native load priority for certain energy transactions to IDACORP Energy; (3) IDACORP failed to file 13 ancillary service agreements involving the sale of power for resale in interstate commerce that it was required to file under Section 205 of the Federal Power Act; (4) IDACORP failed to file 1,182 contracts that IPC assigned to IDACORP Energy for the sale of power for resale in interstate commerce that IPC was required to file under Section 203 of the Federal Power Act; (5) IDACORP failed to ensure that IDACORP Energy provided appropriate compensation from IDACORP Energy to IPC for certain affiliated energy transactions; and (6) IDACORP permitted inappropriate sharing of certain energy pricing and transmission information between IPC and IDACORP Energy. These activities allegedly allowed IDACORP Energy to maintain a false perception of continued growth that inflated its earnings. In addition, the new complaint alleges that those earnings press releases, earnings release conference calls, analyst reports and revised earnings guidance releases issued during the class period were false and misleading. The action seeks an unspecified amount of damages, as well as other forms of relief. IDACORP and the other defendants filed a consolidated motion to dismiss on February 9, 2005, which is now pending.

IDACORP and the other defendants intend to defend themselves vigorously against the allegations. The company cannot, however, predict the outcome of these matters.

Other Legal Issues

Idaho Power Company Transmission Line Rights-of-Way Across Fort Hall Indian Reservation: IPC has multiple transmission lines that cross the Shoshone-Bannock Tribes' Fort Hall Indian Reservation near the city of Pocatello in southeastern Idaho. IPC has been working since 1996 to renew four of the right-of-way permits (for five of the transmission lines), which have stated permit expiration dates between 1996 and 2003. IPC filed applications with the U.S. Department of the Interior, Bureau of Indian Affairs, to renew the four rights-of-way for 25 years, including payment of the independently appraised value of the rights-of-way to the tribes (and the tribal allottees who own portions of the rights-of-way). Due to the lack of definitive legal guidelines for valuation of the permit renewals, IPC is in the process of negotiating mutually acceptable renewal terms with the tribes and allottees. The parties are pursuing a possible 23-year renewal of the permits (including all pre-renewal periods) for a total payment of approximately $7 million to the tribes and allottees. IPC, the tribes and the Bureau of Indian Affairs are currently working through the process of finalizing the agreement, including obtaining the requisite consents from the allottees. The parties hope to obtain the required consents early in 2005. On December 27, 2004, IPC filed an application with the IPUC seeking an accounting order regarding the treatment of this transaction. On February 28, 2005, the IPUC issued an order approving IPC's application procedure.

9. STOCK-BASED COMPENSATION:

The maximum number of shares available under the LTICP is 2,050,000. In 2004 and 2003, IDACORP granted to IPC employees 110,500, 343,000 and 230,000 stock options, respectively, with an exercise price equal to the market price of IDACORP's stock on the date of grant. In accordance with APB 25, no compensation costs have been recognized for the option awards.

Stock option transactions are summarized as follows:

	2004		2003	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price
Outstanding beginning of year	889,800	$ 32.50	594,000	$ 38.33
Granted	110,500	31.21	343,000	22.95
Exercised	(4,200)	22.92	-	-
Forfeited	(40,500)	32.27	(47,200)	36.42
Outstanding end of year	955,600	$ 32.41	889,800	$ 32.50
Exercisable	374,800	$ 35.43	211,600	$ 37.84

The following table summarizes information about stock options outstanding at December 31, 2004:

Outstanding		Exercisable
	Weighted	

Exercise Price Ranges	Number of shares	Weighted average exercise price	average remaining contractual life	Number of shares	Weighted average exercise price
$22.92 - $31.21	428,800	$ 24.98	8.80 years	64,000	$ 22.95
$35.81 - $40.31	526,800	$ 38.45	6.29 years	310,800	$ 38.00

Restricted stock and performance share awards are compensatory awards and IPC accrues compensation expense, which is charged to operations, based upon the market value of the granted shares. For 2004 and 2003, total compensation accrued under the Restricted Stock Plan was less than $1 million annually.

The following table summarizes restricted stock activity:

	2004	2003
Shares outstanding - beginning of year	80,454	77,192
Shares granted	61,806	41,945
Shares forfeited	(24,014)	(1,889)
Shares issued	-	(36,794)
Shares outstanding - end of year	118,246	80,454
Weighted average fair value of current year stock grants on grant date	$ 31.21	$ 22.95

10. BENEFIT PLANS:

Pension Plans

IPC has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. IPC's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2004 and 2003, and does not expect to make a contribution in 2005. The market-related value of assets for the plan is equal to market value.

In addition, IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors. This plan was financed by purchasing life insurance policies and investments in marketable securities, all of which are held by a trustee. The cash value of the policies and investments exceed the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

IPC uses a December 31 measurement date for its plans.

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

	Pension Plan		Deferred Compensation Plan	
	2004	2003	2004	2003
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 339,121	$ 294,881	$ 38,870	$ 35,792
Service cost	11,809	10,173	1,358	1,212
Interest cost	20,437	19,463	2,312	2,414
Actuarial loss (gain)	16,626	27,420	(1,225)	1,786
Benefits paid	(13,660)	(13,345)	(2,670)	(2,369)
Plan amendments	-	529	-	35
Benefit obligation at December 31	374,333	339,121	38,645	38,870
Change in plan assets:				
Fair value at January 1	335,229	282,531	-	-

Actual return on plan assets	34,648	66,043	-	-
Employer contributions	-	-	-	-
Benefit payments	(13,660)	(13,345)	-	-
Fair value at December 31	356,217	335,229	-	-
Funded status	(18,116)	(3,892)	(38,645)	(38,870)
Unrecognized actuarial loss	28,491	18,577	11,443	13,547
Unrecognized prior service cost	5,889	6,660	1,372	1,010
Unrecognized net transition liability	(126)	(389)	310	923
Net amount recognized	$ 16,138	$ 20,956	$ (25,520)	$ (23,390)
Amounts recognized in the statement of financial position consist of:				
Prepaid (accrued) pension cost	$ 16,138	$ 20,956	$ (36,110)	$ (35,676)
Intangible asset	-	-	1,682	1,933
Accumulated other comprehensive income	-	-	8,908	10,353
Net amount recognized	$ 16,138	$ 20,956	$ (25,520)	$ (23,390)
Accumulated benefit obligation	$ 316,498	$ 284,910	$ 36,110	$ 35,676

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

	Pension Plan		Deferred Compensation Plan	
	2004	2003	2004	2003
	(thousands of dollars)			
Service cost	$ 11,809	$ 10,173	$ 1,358	$ 1,212
Interest cost	20,437	19,463	2,312	2,414
Expected return on assets	(27,935)	(23,445)	-	-
Recognized net actuarial loss	-	361	878	744
Amortization of prior service cost	770	729	(361)	(345)
Amortization of transition asset	(263)	(263)	613	613
Net periodic pension cost (benefit)	$ 4,818	$ 7,018	$ 4,800	$ 4,638

Changes in the Deferred Compensation Plan minimum liability increased other comprehensive income by $1 million in 2004 and decreased other comprehensive income by $1 million in 2003.

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

	2005	2006	2007	2008	2009	2010-2014
Pension Plan	$ 13,846	$ 14,277	$ 14,996	$ 16,018	$ 17,244	$ 110,833
Deferred Compensation Plan	$ 2,296	$ 2,345	$ 2,461	$ 2,551	$ 2,721	$ 15,041

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2004 and 2003, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2004	2003	2004	2003
Equity securities	69%	69%	-%	-%
Debt securities	21	21	3	2
Real estate	9	9	-	-
Other (a)	1	1	97	98

Total	100%	100%	100%	100%

(a) The postretirement benefit plan assets are primarily life insurance contracts.

Pension Asset Allocation Policy: The target allocations for the portfolio by asset class are as follows:

Large-Cap Growth Stocks	12%	International Growth Stocks	7%
Large-Cap Core Stocks	12%	International Value Stocks	7%
Large-Cap Value Stocks	12%	Intermediate-Term Bonds	13%
Small-Cap Growth Stocks	7%	Short-Term Bonds	10%
Small-Cap Value Stocks	7%	Core Real Estate	9%
Cash and Cash Equivalents	3%	Venture Capital	1%

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.

There are three major goals in IPC's asset allocation process:

- 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. IPC sets cash allocations sufficient to cover the current year benefit payments and bond allocations sufficient to cover at least five years of benefit payments. IPC then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan.
- Maintain a prudent risk profile consistent with ERISA fiduciary standards. The baseline risk measure is a 60 percent S&P 500 stocks and a 40 percent Lehman Aggregate bond portfolio.

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

Rate-of-return projections for plan assets are based on historical real returns adjusted for inflation for each asset class, based on a recognized index established for the asset class being measured. Historical real returns are then adjusted to include an inflation premium based on the current inflation environment. IPC currently uses a three percent inflation assumption in the asset modeling process.

IPC'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.

Postretirement Benefits

IPC maintains a defined benefit postretirement plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Effective January 1, 2003, IPC amended its postretirement benefit plan. The amendment affects all employees who retire after December 31, 2002, limiting their postretirement benefit to a fixed amount. This amendment will limit the growth of IPC's future obligations under this plan.

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

	2004	2003
Service cost	$ 1,400	$ 1,207
Interest cost	3,974	4,017
Expected return on plan assets	(2,294)	(1,930)
Amortization of unrecognized transition obligation	2,040	2,040

Amortization of prior service cost	(523)	(563)
Recognized actuarial loss	1,489	1,402
Net periodic postretirement benefit cost	$ 6,086	$ 6,173

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

	2004	2003
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 67,090	$ 57,267
Service cost	1,400	1,207
Interest cost	3,974	4,017
Actuarial loss	2,201	8,780
Benefits paid	(3,997)	(4,181)
Plan Amendments	437	-
Benefit obligation at December 31	71,105	67,090
Change in plan assets:		
Fair value of plan assets at January 1	26,603	22,522
Actual return on plan assets	2,301	4,081
Employer contributions	4,577	3,961
Benefits paid	(3,758)	(3,961)
Fair value of plan assets at December 31	29,723	26,603
Funded status	(41,382)	(40,487)
Unrecognized prior service cost	(4,087)	(5,047)
Unrecognized actuarial loss	24,559	23,854
Unrecognized transition obligation	16,320	18,360
Accrued benefit obligations included with other deferred credits	$ (4,590)	$ (3,320)

The assumed health care cost trend rate used to measure the expected cost of benefits covered by the plan was 6.75 percent in 2004 and 2003. A one-percentage point change in the assumed health care cost trend rate would have the following effect (in thousands of dollars):

	1-Percentage-Point increase	decrease
Effect on total of cost components	$ 220	$ (170)
Effect on accumulated postretirement benefit obligation	$ 1,996	$ (1,625)

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

	Pension Benefits		Postretirement Benefits	
	2004	2003	2004	2003
Discount rate	5.75%	6.15%	5.75%	6.15%
Expected long-term rate of return on assets	8.5	8.5	8.5	8.5
Rate of compensation increase	4.5	4.5	-	-
Medical trend rate	-	-	6.75	6.75
Expected working lifetime (years)	-	-	11	12

The following table sets forth the weighted-average assumptions used for the end of each year to determine net periodic benefit cost for all IPC-sponsored pension and postretirement benefit plans:

	Pension	Postretirement

	Benefits		Benefits	
	2004	2003	2004	2003
Discount rate	6.15%	6.75%	6.15%	6.75%
Expected long-term rate of return on assets	8.5	8.5	8.5	8.5
Rate of compensation increase	4.5	4.5	-	-
Medical trend rate	-	-	6.75	6.75
Expected working lifetime (years)	-	-	11	12

FSP FAS 106-1 and FSP FAS 106-2
In January and May 2004, the FASB released FSP FAS 106-1 and FSP FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003."

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

FSP FAS 106-2 provides guidance on accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits and requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. Under FSP FAS 106-1, IPC elected to defer accounting for the effects of the Medicare Act. This deferral remained in effect until the appropriate effective date of FSP FAS 106-2.

FSP FAS 106-2 was effective for the first interim or annual period beginning after June 15, 2004. However, for entities that did not recognize a significant impact, delayed recognition of the effects of the Medicare Act until the next regularly scheduled measurement date following the issuance of FSP FAS 106-2 was required.

The measures of accumulated postretirement benefit obligation and net periodic benefit cost do not reflect any amount associated with the subsidy, because IPC initially determined that the effect of the Medicare Act would not be material. Regulations published on January 28, 2005 provide more flexibility in determining actuarial equivalence to Medicare of the benefits provided by the plan than was initially estimated by IPC's actuaries. Based on these new regulations, IPC estimates that the accumulated postretirement benefit obligation as of January 1, 2005 will be reduced by $6 million, and 2005 periodic postretirement benefit cost will decrease by $1 million.

Employee Savings Plan
IPC has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. IPC matches specified percentages of employee contributions to the plan. Matching contributions amounted to $3 million in both 2004 and 2003.

Postemployment Benefits
IPC provides certain benefits to former or inactive employees, their beneficiaries and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under IPC's disability plans and health care for surviving spouses and dependents. IPC accrues a liability for such benefits. In accordance with an IPUC order, the portion of the liability attributable to regulated activities in Idaho as of December 31, 1993, was deferred as a regulatory asset, and amortized over a ten-year period, which ended in January 2005.

The following table summarizes postemployment benefit amounts included in IPC's balance sheets at December 31 (in thousands of dollars):

	2004	2003
Included with regulatory assets	$ 31	$ 403
Included with other deferred credits	$ 3,924	$ 4,079

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

The following table presents the major classifications of IPC's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2004 and 2003 (in thousands of dollars):

	2004		2003	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,482,517	2.51%	$ 1,456,954	2.62%
Transmission	560,303	2.18	526,887	2.21
Distribution	992,248	2.59	952,979	3.25
General and Other	289,748	10.02	283,408	6.51
Total in service	3,324,816	2.96%	3,220,228	2.99%
Accumulated provision for depreciation	(1,316,125)		(1,239,604)	
In service - net	$ 2,008,691		$ 1,980,624	

IPC has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. IPC's proportionate share of direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of IPC's participation, were as follows at December 31, 2004 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	%	MW
Jim Bridger Units 1-4	Rock Springs, WY	$ 442,367	$ 4,310	$ 255,229	33	707
Boardman	Boardman, OR	66,116	1,277	44,275	10	55
Valmy Units 1 and 2	Winnemucca, NV	310,917	889	184,025	50	261

IPC's wholly owned subsidiary, Idaho Energy Resources Co., is a joint venturer in Bridger Coal Company, which operates the mine supplying coal to the Jim Bridger generating plant. Coal purchased by IPC from the joint venture amounted to $47 million in 2004 and $44 million in 2003.

IPC has contracts to purchase the energy from four Public Utilities Regulatory Policy Act of 1978 (PURPA) Qualified Facilities that are 50 percent owned by Ida-West. Power purchased from these facilities amounted to $7 million, annually in 2004 and 2003.

12. REGULATORY MATTERS:

General Rate Case

Idaho: IPC filed its Idaho general rate case with the IPUC on October 16, 2003. IPC originally requested approximately $86 million annually in additional revenue, an average 17.7 percent increase to base rates. On rebuttal, IPC lowered its overall requested increase to $70 million annually, an average of 14.5 percent. The IPUC approved an increase of $25 million in IPC's electric rates, an average of 5.2 percent, in an order issued on May 25, 2004. The rate increase became effective on June 1, 2004.

In the order, the IPUC approved a return on equity of 10.25 percent, compared to the 11.2 percent IPC requested, an overall rate of return of 7.9 percent, compared to the 8.3 percent requested by IPC. The IPUC reduced the $1.55 billion in rate base requested for IPC's Idaho jurisdiction to $1.52 billion.

Additionally, the IPUC approved higher rates for residential and small-commercial customers during the summer months to encourage conservation. The 12.6 percent higher summer rate applies to monthly usage over 300 kilowatt-hours. The IPUC also ordered time-of-use rates to be phased in for industrial customers, asked IPC to submit a proposal for a conservation program for industrial customers and ordered increased low-income weatherization funding of $1 million annually.

The IPUC also noted two other issues to be addressed in separate proceedings and potentially handled in workshops instead of formal hearings. These issues are: (1) investigating approaches to removing financial disincentives to IPC for investing in cost effective energy efficiency and clean distributed generation and (2) investigating various cost of service issues raised in the general rate case, including those associated with load growth. During the year, initial workshops were held on both issues.

The IPUC disallowed several costs in the Idaho general rate case order, including $12 million annually related to the determination of IPC's income tax expense, $8 million of incentive payments capitalized in prior years and $1 million of capitalized pension expense. On June 15, 2004, IPC filed with the IPUC a petition for reconsideration of these and other items. On July 13, 2004, the IPUC granted this petition in part, agreeing to reconsider the issue relating to the determination of IPC's income tax expense and, in light of the IPUC Staff's computational errors, ordering rates increased by approximately $3 million on or before August 1, 2004. IPC recorded an impairment of assets of $9 million related to the disallowed incentive payments and the disallowed capitalized pension expenses.

On September 28, 2004, the IPUC issued separate orders approving two Settlement Agreements entered into on August 16, 2004 between IPC and the IPUC Staff.

Settlement No. 1, approved by the IPUC in Order No. 29601, relates to the calculation of IPC's taxes for purposes of test year income tax expense. In the Idaho general rate case order, the IPUC adopted the use of a historic five-year average income tax rate to calculate IPC's income tax expense. Settlement No. 1 approved the modification of the general rate case order to utilize IPC's statutory income tax rates to compute test year income tax expense. As a result, IPC will compute and record monthly during the period June 1, 2004 through May 31, 2005 a regulatory asset (with interest accrued at a rate of one percent per annum) of approximately $12 million. Rates will increase on June 1, 2005 to reflect the ongoing impact of the tax expense. Approximately $7 million of this amount was recorded in 2004 as other operating revenue. Settlement No. 1 allows IPC to continue its compliance with the normalization provisions of the Internal Revenue Code of 1986, as amended, and associated Treasury Regulations, and will allow IPC to continue to receive the benefits of accelerated depreciation.

Settlement No. 2, approved by the IPUC in Order No. 29600, resolved outstanding issues related to: (1) an unplanned outage at one of the two units of the North Valmy Steam Electric Generating Plant (Valmy) in the summer of 2003, (2) a matter relating to the expense adjustment rate for growth component of the PCA and (3) regulatory accounting issues related to a tax accounting method change in 2002. In Settlement No. 2, IPC and the IPUC Staff agreed that the IPUC will not examine the cost of replacement power and a possible PCA adjustment resulting from the Valmy outage, and the expense adjustment rate for growth component of the PCA will continue at its existing value until IPC's next general rate case. In September 2004, as a result of the order, IPC established a regulatory liability of $19 million with a charge to PCA expense. A monthly credit of approximately $804,000 will be included in the PCA from June 2004 through May 2006, which will reduce this regulatory liability. Also in September 2004, IPC reversed a $16 million regulatory tax liability by reducing income tax expense. This regulatory tax liability was established in 2002 when IPC changed its tax accounting method for capitalized overhead costs.

The final result of IPC's general rate case was a $40 million increase to the base Idaho jurisdictional revenue requirement, comprised of $25 million in the initial order, $3 million related to computational errors and $12 million in the order approving Settlement No. 1.

On March 2, 2005, IPC made a rate filing with the IPUC to include the investment associated with the construction of the Bennett Mountain Power Plant in Idaho retail rates.

Oregon: On September 21, 2004, IPC filed an application with the OPUC to increase general rates an average of 17.5 percent or approximately $4 million annually. IPC's filing includes a request to introduce summer and non-summer rates similar to proposals that were approved in the Idaho general rate case. IPC has not filed for a change to its overall rates in Oregon since 1995.

On October 19, 2004, the OPUC suspended IPC's request for a period of time not to exceed nine months from October 20, 2004 to investigate the propriety and reasonableness of the request. A pre-hearing conference and public meeting was held on November 18, 2004. The hearing schedule called for a settlement conference, which began on February 14, 2005 and an evidentiary hearing to begin on May 23, 2005. IPC is unable to predict what rate relief the OPUC will grant.

Deferred Power Supply Costs

IPC's deferred net power supply costs consisted of the following at December 31 (in thousands of dollars):

	2004	2003
Oregon deferral	$ 12,047	$ 13,620
Idaho PCA current year net power supply cost deferrals:		
Deferral for 2004-2005 rate year	-	44,664
Deferral for 2005-2006 rate year	22,778	-
Irrigation Lost Revenues	13,290	-
Idaho PCA true-up awaiting recovery:		
Remaining true-up authorized May 2003	-	13,646

Remaining true-up authorized May 2004	11,415	-
Total deferral	$ 59,530	$ 71,930

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portions, is then included in the calculation of the next year's PCA.

On April 15, 2004, IPC filed its 2004-2005 PCA with the IPUC requesting recovery of $71 million above base rates and a proposed effective date of June 1, 2004. On May 25, 2004, the IPUC issued Order No. 29506 approving IPC's filing with additional instructions for IPC and the IPUC Staff to examine the cost of replacement power attributable to the unplanned outage at the Valmy plant in 2003. Based on the order approving Settlement No. 2, discussed above, the IPUC will not examine the costs related to this outage.

On May 15, 2003, the IPUC issued Order No. 29243 approving IPC's 2003-2004 PCA filing, with a small adjustment to the original filing. As approved, IPC's rates were adjusted to collect $81 million above 1993 base rates.

On April 15, 2002, the IPUC issued Order No. 28992 disallowing recovery of $12 million of lost revenues resulting from the Irrigation Load Reduction Program that was in place in 2001. IPC believed that this IPUC order was inconsistent with Order No. 28699, dated May 25, 2001, that allowed recovery of such costs, and IPC filed a Petition for Reconsideration on May 2, 2002. On August 29, 2002, the IPUC issued Order No. 29103 denying the Petition for Reconsideration. As a result of this order, approximately $12 million was expensed in September 2002. IPC believed it was entitled to recover this amount and argued its position before the Idaho Supreme Court on December 5, 2003. On March 30, 2004, the Idaho Supreme Court set aside the IPUC denial of the recovery of lost revenues and remanded the matter to the IPUC to determine the amount of lost revenues to be recovered. On December 29, 2004, the IPUC issued Order No. 29669 allowing IPC to recover $12 million in lost revenues and $2 million in interest. The recovery will be included as part of IPC's annual PCA beginning June 1, 2005.

Oregon: On March 2, 2005 IPC filed for an accounting order to defer net power supply costs for the period of March 1, 2005 through February 28, 2006 in anticipation of the low water conditions IPC is currently experiencing. The net system power supply costs included in this filing was $169 million. IPC is proposing to use the same methodology for this deferral filing that was accepted in 2002 for Oregon's share of IPC's 2001 net power supply expenses.

IPC is also recovering calendar year 2001 excess power supply costs applicable to the Oregon jurisdiction. In two separate 2001 orders, the OPUC approved rate increases totaling six percent, which was the maximum annual rate of recovery allowed under Oregon state law at that time. These increases were recovering approximately $2 million annually. During the 2003 Oregon legislative session, the maximum annual rate of recovery was raised to ten percent under certain circumstances. IPC requested and received authority to increase the surcharge to ten percent. As a result of the increased recovery rate, which became effective on April 9, 2004, IPC will recover approximately $3 million annually.

Wind Down of Energy Marketing

IDACORP announced in 2002 that IE would wind down its energy marketing operations. In connection with the wind down, certain matters were identified that required resolution with the FERC, the IPUC and the OPUC. These matters were resolved in all three jurisdictions.

Idaho: In an IPUC proceeding that began in May 2001, IPC, the IPUC staff and several interested customer groups worked cooperatively to determine the appropriate compensation IE should provide to IPC for certain transactions between the affiliates. The IPUC has issued several orders since then regarding these matters. Order No. 28852 issued on September 28, 2001 covered the time period prior to February 2001. Order No. 29026 covered the time period from March 2001 through March 2002. The IPUC also approved IPC's ongoing hedging and risk management strategies in Order No. 29102 issued on August 28, 2002. This order formalized IPC's agreement to implement a number of changes to its existing practices for managing risk and initiating hedging purchases and sales. The $5.8 million in benefits related to the FERC settlement were included in the 2003-2004 PCA and credited to Idaho retail customers in accordance with the PCA methodology. The parties to the proceeding have executed a settlement agreement providing that an additional $5.5 million be flowed through the PCA mechanism to the Idaho retail customers from April 2003 through December 2005. This agreement was filed with the IPUC on February 17, 2004 and approved on March 15, 2004.

Oregon: Following IPC's settlement with the IPUC on issues related to IPC's past relationship with IE, IPC approached the OPUC to settle the issue of fair compensation to Oregon customers related to the terminated Electricity Supply Management Services Agreement between IPC and IE, as well as any other issues relating to transactions between IPC and IE. On October 4, 2004, IPC filed a petition with the OPUC requesting an accounting order approving a settlement stipulation and authorizing IPC to credit its existing deferral balance of excess power supply costs. In the proposed settlement, IPC agrees to continue the $7,700 monthly credit to customers that began in July 2001 through December 2005, and to reduce the existing excess power supply cost deferral balance by a one time credit of $100,000 on January 1, 2005. The OPUC issued Order No. 04-683 approving this settlement on November 22, 2004.

Regulatory Assets and Liabilities

The following is a breakdown of IPC's regulatory assets and liabilities (in thousands of dollars):

	2004		2003	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Income taxes	$ 344,220	$ 40,447	$ 330,833	$ 41,024
Conservation	17,836	5,205	21,108	5,288
Employee benefits	76	-	993	-
PCA deferral and amortization	34,193	-	58,310	-
Oregon deferral and amortization	12,047	-	13,620	-
Derivatives	-		125	-
Asset retirement obligations	8,372	147,700	6,456	142,595
Deferred investment tax credits	-	66,836	-	67,789
IPUC settlement order	7,119	13,671	-	-
Irrigation lost revenues	13,290	-	-	-
BPA settlement	-	1,833	-	1,735
Incremental security costs	813	-	1,076	-
OPUC settlement	-	100	-	-
Other	815	149	1,508	93
Total	$ 438,781	$ 275,941	$ 434,029	$ 258,524

The regulatory assets related to income taxes and asset retirement obligations do not earn a current return on investment. For further information on the asset retirement obligations amounts, see Note 17.

In the event that recovery of costs through rates becomes unlikely or uncertain, SFAS 71 would no longer apply. If IPC were to discontinue application of SFAS 71 for some or all of its operations, then these items may represent stranded investments. If IPC is not allowed recovery of these investments, it would be required to write off the applicable portion of regulatory assets and the financial effects could be significant.

FERC Market-Based Rate Authority

IPC has FERC-approved market-based rate authority, which permits IPC to sell electric energy at market-based rates rather than cost-based rates. The FERC requires periodic reviews of the conditions under which this market-based rate authority is granted to ensure that the rates charged thereunder are just and reasonable. On April 14, 2004, the FERC issued an order commencing a market power analysis of all companies with market-based rate authority; including IPC. In September 2004, IPC filed a revision of its previously approved (October 9, 2003) market power analysis, which it supplemented in September and October. On March 3, 2005, the FERC issued an order accepting IPC's market power analysis. IPC is required to file another market power analysis on or before March 3, 2008.

13. INVESTMENTS:

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

	2004	2003
IPC Investments:		
Auction rate securities (available-for-sale)	$ 31,650	$ -
Equity method investment	36,544	27,417
Available-for-sale equity securities	21,505	22,438
Executive deferred compensation	6,002	617
Other investments	808	14
Total IPC investments	$ 96,509	$ 50,486

Equity Method Investments
IPC is the sole owner of Idaho Energy Resources Co. (IERCO). IERCO is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

The following table presents IPC's earnings of unconsolidated equity-method investments (in thousands of dollars):

	2004	2003
IERCO	$ 8,190	$ 10,048

Investments in Debt and Equity Securities
Investments in debt and equity securities are accounted for in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Those investments classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

IPC held $32 million of auction rate securities at December 31, 2004. Auction rate securities are long-term instruments whose interest rates or dividends are reset at specific frequencies. The typical reset periods are either 28 or 35 days. The rates or dividends are reset via a Dutch auction. The original maturities of these securities at the time of issuance ranged from 2007 to 2042.

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities have maturities ranging from 2005 through 2009.

The following table summarizes investments in debt and equity securities (in thousands of dollars):

	2004			2003		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities (IPC)	$ 2,530	$ 256	$ 53,155	$ 2,665	$ 276	$ 22,438

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

	2004	2003
Proceeds from sales	$ 266,331	$ 14,040
Gross realized gains from sales	2,044	1,046
Gross realized losses from sales	634	1,169

Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IPC analyzes securities in loss positions as of the end of each reporting period. Any security with an unrealized loss of more than 20 percent is evaluated for other-than-temporary impairment. A security will generally be written down to market value if it has an unrealized loss of 20 percent or more for more than nine months. If additional information is available that indicates a security is other-than-temporarily impaired, it will be written down prior to the nine-month time period. In the alternative, if a security has been impaired for more than nine months but available information indicates that the impairment is temporary, the security will not be written down. IPC recognized other-than-temporary impairments of $0.6 million and $1 million in 2003 and 2002, respectively. These declines are included in other income in the Consolidated Statements of Income. For 2004, it was determined there were no other-than-temporary declines in market value.

The following table summarizes information regarding securities that were in an unrealized loss position at the end of each year, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Aggregate Unrealized Loss	Aggregate Related Fair Value	Aggregate Unrealized Loss	Aggregate Related Fair Value
	Less than 12 months		12 months or longer	
2004:				
Available for sale equity securities (IPC)	$ 181	$ 2,934	$ 75	$ 362
2003:				
Available for sale equity securities (IPC)	$ 200	$ 2,577	$ 76	$ 359

The available-for-sale equity securities in unrealized loss positions are diversified investments in common stock of various companies used to fund IPC's Senior Management Security Plan. The held-to-maturity debt securities in unrealized loss positions are mainly yield-to-maturity bonds, whose market values fluctuate based on the interest rate environment. At December 31, 2004, ten available-for-sale and 14 held-to-maturity securities were in an unrealized loss position. At December 31, 2003, seven available-for-sale and 13 held-to-maturity securities were in an unrealized loss position. All unrealized losses were less than 20 percent. IPC has the ability and intent to hold the equity securities for a reasonable period of time sufficient for a forecasted recovery of fair value and do not consider these investments to be other-than-temporarily impaired at December 31, 2004 or 2003.

14. ASSET RETIREMENT OBLIGATIONS:

On January 1, 2003, IPC adopted SFAS 143, "Accounting for Asset Retirement Obligations." This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. An obligation may result from the acquisition, construction, development or the normal operation of a long-lived asset. SFAS 143 requires an entity to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized at that time. As a rate-regulated entity, IPC records regulatory assets and liabilities instead of accretion, depreciation and gains or losses. This treatment was approved by Order No. 29414 from the IPUC. The regulatory assets recorded under this order do not earn a return on investment.

IPC performed detailed assessments of the applicability and implications of SFAS 143 and identified AROs related to two of IPC's jointly owned coal-fired generation facilities and IPC's transmission and distribution facilities. Upon adoption, IPC recorded an ARO of $7 million, fixed assets of $2 million, accumulated depreciation of $1 million and a regulatory asset of $6 million. These amounts do not include an amount for the transmission and distribution facilities, because, based on the indeterminate life of these assets, an ARO calculation cannot be made.

The regulated operations of IPC also collect removal costs in rates for certain assets that do not have associated AROs. The adoption of SFAS 143 required IPC to redesignate these removal costs as regulatory liabilities. As of December 31, 2004, IPC had $148 million of such costs recorded as regulatory liabilities on its Balance Sheet.

An ARO also exists for the reclamation of the Bridger Coal mine property, which is leased by Bridger Coal Company, an equity-method investee of IPC. As Bridger Coal Company has a March 31 fiscal year end, it adopted SFAS 143 on April 1, 2003. Upon adoption of SFAS 143, IPC did not record a net change in its investment in Bridger Coal Company, as Bridger Coal Company also is applying regulatory accounting, recording regulatory assets and liabilities instead of accretion, depreciation and gains or losses.

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

	2004	2003
Balance at beginning of year	$ 7,140	$ -
Amount recorded on adoption	-	6,743
Accretion expense	421	397
Revisions in estimated cash flows	1,727	-
Balance at end of year	$ 9,288	$ 7,140

15. RELATED PARTY TRANSACTIONS:

IDACORP

In exchange for the transfer of Energy Marketing to IE in June 2001, IPC received a partnership interest in IE, which was then transferred to IDACORP in exchange for notes receivable from IDACORP totaling approximately $76 million. The notes receivable were due over periods of one to ten years, bore interest at IDACORP's overall variable short-term borrowing rate and were paid in full in 2003.

IPC performs corporate functions such as financial, legal and management services for IDACORP and its subsidiaries. IPC charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. IPC billed IDACORP $4 million and 3 million in 2004 and 2003, respectively, for these services.

The following table presents IPC's sales to and purchases from IE for the years ended December 31:

	2004	2003
	(thousands of dollars)	
Sales to IE	$ -	$ 2,268
Purchases from IE	-	-

IDACOMM

IPC provides project management and engineering services to IDACOMM. IDACOMM also pays joint use fees to IPC. Total fees charged to IDACOMM were $0.3 million and $0.3 million in 2004 and, 2003, respectively.

Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects. IPC paid $7 million per year in 2004 and 2003.

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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	04/22/2005	End of 2004/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Quarter/Year	1,133,481	5,975,642		
2	Preceding Quarter/Year Reclassification from Account 219 to Net Income	166,576			
3	Preceding Quarter/Year Changes in Fair Value	(4,976,593)	330,059		
4	Total (lines 2 and 3)	(4,810,017)	330,059		
5	Balance of Account 219 at End of Preceding Quarter/Year / Beginning of	(3,676,536)	6,305,701		
6	Current Quarter/Year Reclassifications from Account 219 to Net Income	1,195,783			
7	Current Quarter/Year Changes in Fair Value	(2,057,039)	(880,135)		
8	Total (lines 6 and 7)	(861,256)	(880,135)		
9	Balance of Account 219 at End of Current Quarter/Year	(4,537,792)	5,425,566		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 72) (i)	Total Comprehensive Income (j)
1			7,109,123		
2			166,576		
3			(4,646,534)		
4			(4,479,958)		(4,479,958)
5			2,629,165		
6			1,195,783		
7			(2,937,174)		
8			(1,741,391)		(1,741,391)
9			887,774		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) 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)	3,325,270,233	3,325,270,233
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,325,270,233	3,325,270,233
9	Leased to Others		
10	Held for Future Use	2,635,710	2,635,710
11	Construction Work in Progress	151,651,719	151,651,719
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	3,479,103,213	3,479,103,213
14	Accum Prov for Depr, Amort, & Depl	1,316,124,554	1,316,124,554
15	Net Utility Plant (13 less 14)	2,162,978,659	2,162,978,659
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,272,087,500	1,272,087,500
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	44,319,189	44,319,189
22	Total In Service (18 thru 21)	1,316,406,689	1,316,406,689
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	-282,135	-282,135
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,316,124,554	1,316,124,554

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
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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	04/22/2005	End of 2004/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	9,431,537	737,485
4	(303) Miscellaneous Intangible Plant	62,357,443	4,594,415
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	71,794,683	5,331,900
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,282,073	
9	(311) Structures and Improvements	129,615,530	387,606
10	(312) Boiler Plant Equipment	460,580,217	15,907,337
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	112,666,050	3,949,232
13	(315) Accessory Electric Equipment	61,081,431	25,543
14	(316) Misc. Power Plant Equipment	12,469,665	290,505
15	(317) Asset Retirement Costs for Steam Production	2,060,293	714,827
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	779,755,259	21,275,050
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	13,935,724	
28	(331) Structures and Improvements	127,904,128	1,250,581
29	(332) Reservoirs, Dams, and Waterways	242,747,168	723,010
30	(333) Water Wheels, Turbines, and Generators	184,436,422	1,327,214
31	(334) Accessory Electric Equipment	35,567,465	835,885
32	(335) Misc. Power PLant Equipment	13,921,838	278,599
33	(336) Roads, Railroads, and Bridges	6,933,691	16,739
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	625,446,436	4,432,028
36	D. Other Production Plant		
37	(340) Land and Land Rights	219,037	
38	(341) Structures and Improvements	1,207,423	
39	(342) Fuel Holders, Products, and Accessories	1,676,666	
40	(343) Prime Movers	765,800	
41	(344) Generators	43,902,850	-8,839
42	(345) Accessory Electric Equipment	1,484,491	693,056
43	(346) Misc. Power Plant Equipment	2,495,933	16,943

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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
			10,169,022		3
372,019			66,579,839		4
372,019			76,754,564		5
					6
					7
			1,282,073		8
			130,003,136		9
			476,487,554		10
					11
			116,615,282		12
			61,106,974		13
67,546			12,692,624		14
			2,775,120		15
67,546			800,962,763		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			13,935,724		27
64,006			129,090,703		28
64,632			243,405,546		29
411,206			185,352,430		30
203,428			36,199,922		31
34,217			14,166,220		32
			6,950,430		33
					34
777,489			629,100,975		35
					36
			219,037		37
			1,207,423		38
			1,676,666		39
			765,800		40
			43,894,011		41
			2,177,547		42
			2,512,876		43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	51,752,200	701,160
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,456,953,895	26,408,238
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	21,544,591	864,639
49	(352) Structures and Improvements	31,091,076	244,279
50	(353) Station Equipment	212,659,800	16,981,383
51	(354) Towers and Fixtures	66,963,061	9,690,407
52	(355) Poles and Fixtures	88,514,840	1,719,921
53	(356) Overhead Conductors and Devices	105,794,879	5,851,156
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	318,351	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	526,886,598	35,351,785
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,856,375	3,519
61	(361) Structures and Improvements	16,411,186	2,337,987
62	(362) Station Equipment	127,254,783	3,272,139
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	180,886,200	6,171,179
65	(365) Overhead Conductors and Devices	94,018,650	2,089,880
66	(366) Underground Conduit	35,554,518	3,753,303
67	(367) Underground Conductors and Devices	136,740,442	11,821,122
68	(368) Line Transformers	264,816,827	19,261,035
69	(369) Services	46,992,042	-385,991
70	(370) Meters	40,201,148	8,021,048
71	(371) Installations on Customer Premises	2,284,690	234,712
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,961,700	51,941
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	952,978,561	56,631,874
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	8,601,230	12,206
78	(390) Structures and Improvements	58,714,075	1,884,680
79	(391) Office Furniture and Equipment	54,512,568	8,787,640
80	(392) Transportation Equipment	43,214,649	1,783,867
81	(393) Stores Equipment	971,547	42,959
82	(394) Tools, Shop and Garage Equipment	3,564,226	391,919
83	(395) Laboratory Equipment	8,879,874	761,848
84	(396) Power Operated Equipment	6,170,547	181,643
85	(397) Communication Equipment	25,337,886	2,572,265
86	(398) Miscellaneous Equipment	2,102,526	265,917
87	SUBTOTAL (Enter Total of lines 77 thru 86)	212,069,128	16,684,944
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	212,069,128	16,684,944
91	TOTAL (Accounts 101 and 106)	3,220,682,865	140,408,741
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	3,220,682,865	140,408,741

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					44
			52,453,360		45
845,035			1,482,517,098		46
					47
63			22,409,167		48
28,117			31,307,238		49
1,332,399			228,308,784		50
80,221			76,573,247		51
309,685			89,925,076		52
184,774			111,461,261		53
					54
					55
			318,351		56
					57
1,935,259			560,303,124		58
					59
415,885			3,444,009		60
27,054			18,722,119		61
676,851			129,850,071		62
					63
1,294,426			185,762,953		64
1,972,409			94,136,121		65
93,924			39,213,897		66
745,979			147,815,585		67
11,095,884			272,981,978		68
193,848			46,412,203		69
765,563			47,456,633		70
35,720			2,483,682		71
					72
44,694			3,968,947		73
					74
17,362,237			992,248,198		75
					76
51,178			8,562,258		77
392,033			60,206,722		78
11,292,854			52,007,354		79
1,167,348			43,831,168		80
7,593			1,006,913		81
123,549			3,832,596		82
411,692			9,230,030		83
27,567			6,324,623		84
1,809,426			26,100,725		85
23,583			2,344,860		86
15,306,823			213,447,249		87
					88
					89
15,306,823			213,447,249		90
35,821,373			3,325,270,233		91
					92
					93
					94
35,821,373			3,325,270,233		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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		768,377
3				
4	Production			229,433
5				
6	Transmission Stations			360,819
7				
8	Transmission Lines			73,987
9				
10	Distribution Stations			755,054
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Boise Mechanical and Electrical Shop	12/31/01		47,000
24	Transmission Stations	12/31/81		178,094
25	Distribution Stations			150,161
26				
27				
28				
29				
30				
31	Column B if no date listed it is various			
32				
33	Column C is unknown			
34				
35				
36				
37				
38				
39				
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41				
42				
43				
44				
45				
46				
47	Total			2,635,710

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BENNETT MOUNTAIN POWER PLANT C	41,079,528
2	ROLLUP RELIC COST BROWNLEE	26,189,523
3	ROLLUP RELIC COST HELLS CANYON	18,036,588
4	ROLLUP RELIC COST OXBOW	8,168,601
5	LCST0201 ADD T231, CDWL LINE	2,719,258
6	HELLS CANYON RELICENSING OUTSI	2,583,911
7	RTSN0301 NEW SWITCHING STATION	2,092,174
8	ROLLUP RELIC COST LOW MALAD	1,748,987
9	LINE #470, 2ND 138KV LINE TO M	1,556,034
10	CAPITALIZED SPARE PARTS 2004 B	1,545,664
11	NAMPA - ADD 230KV TRANSFORMER	1,452,158
12	BRIDGER UNDISTRIBUTED WORK ORD	1,426,277
13	RIGHT OF WAY/PERMITTING BENNET	1,368,352
14	BOBN0302 INSTALL 230 KV 60 MVA	1,243,820
15	TERR HELLS CANYON RELICENSING-	1,199,021
16	BMPR0301 BENNETT MT. POWER PLA	1,135,063
17	VALMY UNDISTRIBUTED WORK ORDER	1,103,199
18	ROLLUP RELIC COST UP MALAD	1,098,733
19	BOARDMAN UNDISTRIBUTED WORK OR	1,006,529
20	342 COST CENTER DELIVERY CAPIT	954,331
21	HCC ENGINEERING RELICESNING ST	871,633
22	598 COST CENTER DELIVERY CAPIT	786,255
23	418-COST CENTER DELIVERY CAPIT	706,031
24	EMS/ADVANCED APPLICATION PROJE	632,230
25	HCC SUPPORT - 2004	631,999
26	NAMPA TAP ROW ACQUISITION	596,352
27	CAPITALIZED SPARE PARTS 2004 D	575,124
28	COST CENTER 316 DELIVERY CAPIT	548,352
29	BRIDGER 2005C100 U2 3 4 SDCC H	531,189
30	GENERATION OVERHEADS	525,683
31	RELICENSING: HCC SEDIMENT & GE	511,338
32	HCC RELICENSING FISH2004 FEASI	490,010
33	REL-HCC SEDIMENTATION STUDIES	454,600
34	WQ ONGOING HELLS CANYON RELICE	433,621
35	390 COST CENTER DELIVERY CAPIT	431,040
36	FSH-DEV. WHITE STURGEON CONSER	427,004
37	577 COST CENTER DELIVERY CAPIT	424,967
38	BRIDGER 2005C007 REWIND #2 MAI	424,311
39	360 COST CENTER DELIVERY CAPIT	422,001
40	HELLS CANYON COMPLEX	418,294
41	FISH2004 CAPITAL PAHSIMEROI SP	417,610
42	BRIDGER 2005C003 U2 CONTROLS U	412,028
43	TOTAL	151,651,719

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	336-COST CENTER DELIVERY CAPIT	409,535
2	PAYROLL & IBNR ACCRUAL	402,675
3	HCC RESERVOIR/DISCHARGE WQ	395,600
4	HELLS CANYON RELICENSING	390,653
5	RIGHT OF WAY, LINE 470, HORSE	383,997
6	FISH-HCC-REDBAND TROUT/BULL TR	364,283
7	COST CENTER 310 DELIVERY CAPIT	344,325
8	FISH-HELLS CANYON INSTREAM FLO	336,578
9	410-COST CENTER DELIVERY CAPIT	332,489
10	HCC RELICENSING, FISH2004 REDB	329,220
11	343 COST CENTER DELIVERY CAPIT	324,369
12	HRFT0201 NEW STN	322,838
13	CONTINGENCY FUNDS FOR VOICE AN	319,185
14	415-COST CENTER DELIVERY CAPIT	313,604
15	392 COST CENTER DELIVERY CAPIT	311,488
16	REL-HELLS CANYON COMPLEX FY200	310,442
17	324-COST CENTER DELIVERY CAPIT	295,651
18	CALL CENTER LABOR HOURS FOR LI	291,147
19	REL - FLOW MODELING	290,710
20	CONSTRUCTION ACCOUNTING CAPITA	285,543
21	IPCO-RECONDUCTOR MIDVALE 011 F	284,468
22	NEW UNIT 8865 - ETHAN MORGAN -	278,792
23	IPCO-RECONDUCTOR NWPM 011 4 MI	269,974
24	Delivery Overheads	269,832
25	BSU SECOND FEEDER-INSTALL SECO	262,707
26	HAILEY TEAM CAP OH WORK ORDER	262,302
27	BRIDGER 2005C068 REPL 01 RAW W	261,633
28	CMBG-012 REBUILD 6 MI 8A & 4	260,705
29	CHQ PBX - EMERGENCY POWER EXTE	260,021
30	CAPITAL OVERHEADS FOR CADD & A	259,720
31	COST CENTER 320 DELIVERY CAPIT	257,669
32	IDAHO 252 ACCOUNT ADJUSTING EN	254,889
33	COST CENTER 270 TIME WORK ORDE	254,747
34	IPCO-RECONDUCTOR EMET 013 FROM	254,109
35	RELICENSING: SWAN FALLS	246,647
36	WQ-HCC TMDL/401-2003-CAPITAL	241,278
37	REL HCC BAKER COUNTY SETTLEMEN	239,698
38	COST CENTER 317 DELIVERY CAPIT	236,152
39	575 COST CENTER DELIVERY CAPIT	229,010
40	IPCO-KARCHER RD EXIT RELOCATIO	226,222
41	370 -COST CENTER DELIVERY CAPI	223,018
42	FISH-HCC-ANADROMOUS FISH BELOW	221,197
43	TOTAL	151,651,719

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STKY 138KV SWITCHING STATION	219,046
2	404 COST CENTER DELIVERY CAPIT	215,981
3	BRIDGER 2005C094 REPL 11 FEEDW	212,334
4	COST CENTER 321 DELIVERY CAPIT	210,720
5	328-COST CENTER DELIVERY CAPIT	208,689
6	BRIDGER 2005C002 REPL 21 FEEDW	203,265
7	TELECOM/DATA TEAM - REMOTE ACC	200,507
8	REC-HCC RELICENSING PROCESS	200,318
9	420-COST CENTER DELIVERY CAPIT	197,771
10	HCC RELICENSING, FISH2004 ANAD	196,394
11	COST CENTER 318 DELIVERY CAPIT	195,841
12	MPSN0306 UPGRADE COMM FOR BMPR	195,402
13	HAILEY OPERATIONS DESIGN/CONST	188,690
14	TOOL EXP TRANS TO CONST	188,428
15	100-COST CENTER DELIVERY CAPIT	187,109
16	CHERRY STATION	184,010
17	REL - SWAN FALLS FY2004 CAPITA	180,746
18	152 COST CENTER DELIVERY CAPIT	180,347
19	337-COST CENTER DELIVERY CAPIT	180,279
20	BOARDMAN 21870 REWIND GENERATO	178,952
21	334-COST CENTER DELIVERY CAPIT	178,948
22	HILEX POLY CO LLC-40 W 100 S/J	178,334
23	REPLACE T131	176,886
24	IPCO-POLE REPLACEMENT ON LINE	175,851
25	VMWARE ENVIRONMENT	174,970
26	DELIVERY CAPITAL OVERHEADS FOR	172,371
27	FIREWALL UPGRADE	170,048
28	NEW UNIT 6704 - LARRY ADAMS -	168,626
29	159 COST CENTER DELIVERY CAPIT	168,363
30	UPGRADE CHQ PBX TO NEW VERSION	167,646
31	326-COST CENTER DELIVERY CAPIT	166,534
32	ADAMSFAM TEAM CAP OH WORK ORDE	165,727
33	LINE #902, BOISE BENCH-MIDPOIN	163,842
34	GOODING TEAM CAP OH WORK ORDER	162,177
35	PURCHASE "FUEL CELL" FOR FOOTH	161,051
36	BOARDMAN 21670 REPL PRIMARY AI	160,282
37	BOARDMAN 21435 INSTALL NEW STA	159,455
38	TFEAST TEAM CAP OH WORK ORDER	159,362
39	335-COST CENTER DELIVERY CAPIT	159,248
40	455-COST CENTER DELIVERY CAPIT	157,729
41	LINE #438 CDAL-LCST IMPROVE RO	157,660
42	327-COST CENTER DELIVERY CAPIT	157,527
43	TOTAL	151,651,719

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	FISH HELLS CANYON RELICENSING	157,436
2	TWINWEST TEAM CAP OH WORK ORDE	157,232
3	OREGON REAUTHORIZATION - HELLS	153,550
4	PTSN - INSTALL 230 KV SHUNT CA	151,303
5	NEXUS ENERGY SOFTWARE IMPLEMEN	150,747
6	PASSPORT ICF BO'S:MR, CATALOG,	146,413
7	375 COST CENTER DELIVERY CAPIT	146,244
8	GLANBIA FOODS INC-1572 E HIGHW	143,309
9	REL-HCC OREGON REAUTHORIZATION	142,246
10	NEW UNIT 8866 - BRET JUDY - BO	140,518
11	WQ-HCC MITIGATION-RESERVOIR AE	139,632
12	SOX SOFTWARE PROJECT	139,313
13	BRIDGER 2001C004 U2 COUTANT SL	138,699
14	210-COST CENTER DELIVERY CAPIT	136,794
15	LINE #912, BOISE BENCH-MIDPOIN	134,303
16	TERR HELLS CANYON COMPLEX TRAN	131,925
17	MISCELLANEOUS DELIVERY HARDWAR	130,371
18	FISH-MALADS FISH PROJECTS-2002	129,943
19	SWAN FALLS RELICENSING INITIAL	126,767
20	LINE 438, RIGHT OF WAY, VICTOR	125,832
21	IPCO* INSTALL SPOILERS- LUCKY	122,889
22	OXBOW HATCHERY CAPITAL EXPANSI	122,154
23	FISH-HCC-RESIDENT FISH-2003-CA	119,505
24	BRIDGER 2006C003 U2 REHEATER L	119,505
25	MINI CASSIA TEAM CAP OH WORK O	119,395
26	VILLAGERS 2004 CHANGE OUT VAUL	119,268
27	WQ-HCC MITIGATION-TURBINE VENT	119,151
28	COST CENTER 290 DELIVERY CAPIT	118,993
29	STORAGE - ADD MAINFRAME TO SAN	117,997
30	REC-SWAN FALLS RELICENSING PRO	117,674
31	CORRECTION WORK ORDER FOR BOC	117,546
32	MID-SNAKE SUPPORT (PM&E) 2004	117,332
33	377 -COST CENTER DELIVERY CAPI	116,751
34	REL - GEOMORPHOLOGY	115,986
35	NEW UNIT 6698 - DAN SCHLEDEWIT	115,765
36	BRIDGER 2001C004 U2 & 3 BURNER	115,493
37	CLIENT SVRS MGR - MICROSOFT PR	115,480
38	NEWMAN GROUP -- OMS/GIS SERVER	114,883
39	HCC RELICENSING FISH2004 RESID	114,823
40	BUHL0204 RESOLVE BUS CLEARANCE	113,687
41	STORAGE MANAGEMENT SOFTWARE	113,566
42	SRCK INSTALL SCADA	111,170
43	TOTAL	151,651,719

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	NEW UNIT 6699 - DAN SCHLEDEWIT	110,922
2	IPCO/ETGT-011 BUILD NEW FEEDER	110,878
3	378 -COST CENTER DELIVERY CAPI	109,859
4	REPLACE UNIT TRASHRACK	109,525
5	PAHSIMEROI HATCHERY-CAPITAL-FI	109,345
6	576 COST CENTER DELIVERY CAPIT	106,694
7	PURCHASE AND INSTALL AN ADDITI	103,765
8	BORA 345KV CIRCUIT SWITCHER RE	101,877
9	FISH-HCC-FEASIBILITY OF REINTR	101,254
10	NORTHRIDGE IX SUBD.-75-LOTS ON	101,186
11	CHQ6 REMODEL TENANT SPACE	101,116
12	NEW UNIT 6701 - GUY JOHNSTON -	100,882
13	431-COST CENTER DELIVERY CAPIT	100,580
14	OTHER MINOR WORK ORDERS	-4,393,765
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43	TOTAL	151,651,719

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,205,223,473	1,205,223,473		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	90,986,890	90,986,890		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts	2,494,007	2,494,007		
8	Other Accounts (Specify, details in footnote):				
9	Acct 151 Fuel Stock	108,409	108,409		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	93,589,306	93,589,306		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	34,982,230	34,982,230		
13	Cost of Removal	-2,832,015	-2,832,015		
14	Salvage (Credit)	970,889	970,889		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	31,179,326	31,179,326		
16	Other Debit or Cr. Items (Describe, details in footnote):	4,454,047	4,454,047		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,272,087,500	1,272,087,500		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	385,155,364	385,155,364		
21	Nuclear Production				
22	Hydraulic Production-Conventional	217,545,265	217,545,265		
23	Hydraulic Production-Pumped Storage				
24	Other Production	5,664,338	5,664,338		
25	Transmission	196,980,645	196,980,645		
26	Distribution	385,008,939	385,008,939		
27	General	81,732,949	81,732,949		
28	TOTAL (Enter Total of lines 20 thru 27)	1,272,087,500	1,272,087,500		

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

Relocation reimbursements, Up and Down costs and damage and insurance claims $266,766.

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	$ (483,665)
Embedded removal in Accumulated Provision for Depreciation	$ 5,104,848
Disallowed capital cost from the 2003 Idaho rate case	$ (9,075,230)
Total	$ (4,454,047)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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			24,954,085
5				
6	Subtotal Idaho Energy Resources			27,417,179
7				
8				
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41				
42	Total Cost of Account 123.1 $ 2,463,093		TOTAL	27,417,179

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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
9,127,301		34,081,386		4
				5
9,127,301		36,544,480		6
				7
				8
				9
				10
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9,127,301		36,544,480		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)	6,228,205	6,450,733	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	9,899,572	10,372,441	
8	Transmission Plant (Estimated)	3,631,113	4,805,201	
9	Distribution Plant (Estimated)	4,057,507	10,171,811	
10	Assigned to - Other (provide details in footnote)	1,200,134	29,324	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	18,788,326	25,378,777	Electric
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	966,741	685,830	Electric
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	25,983,272	32,515,340	

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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	None					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	None					
22						
23						
24						
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48						
49	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	04/22/2005	End of 2004/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 $50,000 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	Meridian Periodic Payments - IPUC	6,455,677	4,783,462	108	2,866,646	8,372,493
2	order #25533(amort period 1/96 thru 12/03)					
3						
4	Postretirement Benefits - IPUC order #25550	590,200		401	544,800	45,400
5	(amort period 2/95 thru 01/05)					
6						
7	Reorganization Costs - IPUC order 26216	1,508,112		401	754,057	754,055
8	OPUC order #95-1262 (amort 01/96 thru 12/05)					
9						
10	Regulatory Unfunded Accumulated Deferred Income Tax	330,832,743	15,339,388	282	1,952,556	344,219,575
11						
12	Power Cost Adjustment - IPUC order #27516	58,309,992	79,238,072	Footnote	103,538,693	34,009,371
13	(amort period 5/01 thru 05/02)					
14						
15	Idaho - Demand Side Management - IPUC order	21,076,955		401	3,242,604	17,834,351
16	#27660 (amort period 7/98 thru 6/10)					
17						
18	FAS112 Post Employment Benefits	402,536		401	371,508	31,028
19	(Amort period 4/03 thru 3/04)					
20						
21	Excess Power Amortization - Oregon	13,620,313	1,016,865	401	2,589,681	12,047,497
22	(Amort period $1.6 mill per yr until full amort)					
23						
24	Security Costs 2001-2002	728,766	44,527	Footnote	219,899	553,394
25	(Amort period 1/03 thru 12/07)					
26						
27	Security Costs - Incremental	347,339	451,704	Footnote	539,260	259,783
28						
29	Professional Fees - IPUC order #29505		80,110	4073	19,944	60,166
30	(Amort Period 1-03 thru 12-07)					
31						
32	IPUC Order 29601		7,118,562	N/A		7,118,562
33	(Amort Period 6/05 thru 5/06)					
34						
35	Power cost Adjustment - IPUC Order 29670		182,954	N/A		182,954
36	(Amort Period 6/05 thru 5/06)					
37						
38	Irrigation Lost Revenue - IPUC Order 29669		13,289,763	N/A		13,289,763
39	(Amort Period 6/05 thru 5/06)					
40						
41	Minor items (2)	155,834	114,865	Various	268,263	2,436
42						
43						
44	TOTAL	434,028,467	121,660,272		116,907,911	438,780,828

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/22/2005	2004/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 12 Column: d

401	51,610,165.00
253	2,000,000.00
254	5,629,167.00
1823	44,285,289.00
4210	14,073.00
	103,538,694.00

Schedule Page: 232 Line No.: 24 Column: d

401	215,448.00
4210	1,083.00
4171	3,368.00
	219,899.00

Schedule Page: 232 Line No.: 27 Column: d

401	88,975.00
1823	352,412.00
131	94,318.00
4210	864.00
232	2,691.00
	539,260.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, 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	Regional Transmsn Org - (RTO)	2,558,394	651,292	Footnote	958,572	2,251,114
2						
3	Advance prepaid coal royalties	2,374,674		131	197,845	2,176,829
4						
5	Benefits plan - intangible asst	1,933,273		253	251,449	1,681,824
6						
7	Security Plan	27,546,101	2,237,436	426	1,607,711	28,175,826
8						
9	American Falls bond refinance	308,023	6,059	401	20,612	293,470
10						
11	Expense of Issue	128,785	190,780	Footnote	319,565	
12						
13	Company owned Life Insurance	8,077,714	1,140,689	426	1,628,865	7,589,538
14						
15	American Falls water rights	19,885,000				19,885,000
16						
17	Milner bond guarantee	11,700,000				11,700,000
18						
19	Southwest intertie project -	6,255,403	30,703			6,286,106
20	right of way costs					
21						
22	CSPP receivable	1,820,481		143	431,220	1,389,261
23						
24	American Falls - bond refinance	1,015,981		401	47,999	967,982
25	(35 year amortization)					
26						
27	Transmission Deposit-PacifiCorp	151,875				151,875
28						
29	Shelf Registration		1,135,273	Footnote	551,896	583,377
30						
31	Floating Rate Note					
32						
33	Irrigation Lost Revenue	12,015,187		182	12,015,187	
34						
35	Minor Items & Job Orders (4)	-28,295	33,206,710	Footnote	33,157,435	20,980
36						
37	Humbolt Refinance	1,722,096	7,549	Footnote	1,729,645	
38						
39	Valmy Power Plant	195,407	830,801	401	1,046,670	-20,462
40						
41	Customer Svcs Finance Program	371,793	251,730	Footnote	483,393	140,130
42						
43	Stock Valuation	25,000		214	25,000	
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	98,056,892				83,272,850

Schedule Page: 233 Line No.: 1 Column: d

232	18,867
124	752,309
401	187,396
	958,572

Schedule Page: 233 Line No.: 11 Column: d

186	143,017
146	176,548
	319,565

Schedule Page: 233 Line No.: 29 Column: d

181	524,419
232	4,073
401	23,404
	551,896

Schedule Page: 233 Line No.: 35 Column: d

131	32,951,173
142	151,166
232	35,586
186	6,104
141	5,395
401	8,011
	33,157,435

Schedule Page: 233 Line No.: 37 Column: d

181	1,698,285
186	27
401	31,333
	1,729,645

Schedule Page: 233 Line No.: 41 Column: d

131	252,406
141	207,943
142	23,044
	483,393

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Advances for Construction	4,162,170	5,357,402
3	FASB 109 Accounting	41,023,911	40,447,291
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	45,186,081	45,804,693
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify) See note 1 Below	16,151,050	26,907,422
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	61,337,131	72,712,115

Notes

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

Other:	Beginning Balance	Ending Balance
Senior Management Security Plan	9,144,234.16	9,977,022.94
Minimum Pension Liability	4,047,637.89	3,482,677.99
Rate Case Disallowance	0.00	3,432,123.06
Micron-CIAC	2,959,943.40	2,717,223.65
Other Employee's Long Term Deferred Compensation	241,098.47	2,346,499.89
FERC Settlement Reserve	1,563,799.60	781,899.64
SFAS112 - Post Retirement Benefits	1,112,094.41	1,157,159.60
Non-VEBA Pension and Benefits	950,421.76	926,069.06
Post Retiree Benefits-VEBA	344,118.89	867,674.86
SHOBAN Transmission Right of Way Expense	0.00	339,874.34
Restricted Stock Plan	98,934.20	275,928.63
Meridian Gold Contributions	263,239.93	241,127.78
Dark Fiber Contracts	0.00	101,285.39
Seattle City Light-CIAC	111,819.09	80,030.13
Start-up and Organization Costs	75,681.26	75,446.69
Other Regulatory Liabilities	532,014.56	52,999.96
Loss on Pioneer Land Write-down	45,351.37	45,351.37
SMSP-Market Change of Rabbi Investments	223,334.10	7,026.93
Bonus Deferral	(5,562,673.52)	0.00
	16,151,049.57	26,907,421.91

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204			
7				
8	On September 20, 2004 the company redeemed			
9	all of its outstanding preferred stock			
10				
11				
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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	04/22/2005	End of 2004/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
41,458,503	97,877,030					2
						3
41,458,503	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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

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

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

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations received from stockholders	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock	
4		
5	Account 210 - Gain on reacquired Capital Stock	
6		
7		
8	Account 211	
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40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Preferred Stock: (1)	
4		
5		
6		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14	(1) On September 20, 2004 the company redeemed all of its oustanding preferred stock.	
15	See note on pages 122.5 thru 123.6 for additional information.	
16		
17		
18		
19		
20		
21		
22	TOTAL	2,096,925

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	5.50% Series due 2033	70,000,000	728,701
4			36,400 D
5			
6	7.38% Series Due 2007	80,000,000	807,871
7			
8	7.20% Series due 2009	80,000,000	572,246
9			
10	8.00% Series due 2004	50,000,000	463,337
11			400,000 D
12			
13	5.83% Series due 2005	60,000,000	2,508,801
14			
15	6.60% Series due 2011	120,000,000	860,502
16			
17			
18	4.25%Series due 2013	70,000,000	641,201
19			374,500 D
20			
21	4.75% Series due 2012	100,000,000	944,356
22			1,047,617 D
23			
24	6.00% Series due 2032	100,000,000	1,069,356
25			543,244 D
26	5.50% Series due 2034 (Idaho IPC-E-03-3, Oregon UF 4196,	55,000,000	524,419
27	Wyoming 2005-es-03-24)		383,322 D
28			
29	5.875 Series due 2034 (idaho IPC-E-03-3, Oregon UF 4196	50,000,000	746,961 D
30	Wyoming 2005-es-03-24)		
31	Pollution control Revenue Bonds		
32	6.05% Series 96A due 2026	68,100,000	571,895
33	TOTAL	1,038,959,184	15,830,530

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05-01-03	04-01-33	05-01-03	03-31-33	70,000,000	3,850,000	3
						4
						5
12/1/00	12/1/07	12/1/00	12/1/07	80,000,000	5,904,000	6
						7
11/23/99	12/1/09	1/1/00	1/1/10	80,000,000	5,760,000	8
						9
03/25/92	03/15/04	03/21/92	03/15/04		833,333	10
						11
						12
09/09/98	09/09/05	09/09/98	09/09/05	60,000,000	3,498,000	13
						14
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	15
						16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
8/16/04	8/16/34	8/16/04	8/16/34	55,000,000	2,100,694	26
						27
						28
3/26/04	3/15/34	3/26/04	3/15/34	50,000,000	1,218,488	29
						30
						31
07/25/96	07/15/26	07/25/96	07/15/26	68,100,000	4,120,050	32
				987,045,000	50,317,585	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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			471,252 D
2			
3	Series 96B due 2026	24,200,000	124,587
4			
5	Series 96C due 2026	24,000,000	123,561
6			
7	Port of Morrow Variable due 2027	4,360,000	188,545
8			
9	Humboldt Variable due 2024	49,800,000	1,697,856
10			
11	Subtotal Account 221	1,005,460,000	15,830,530
12			
13	Account 224:		
14	Other Long-Term Debt		
15			
16	Bond Guarantee - American Falls	19,885,000	
17			
18	Note Guarantee - Milner Dam	11,700,000	
19	REA Notes	1,914,184	
20	Subtotal Account 224	33,499,184	
21			
22	Account 222 - Reacquired Bonds		
23	Account 223 - Advances from Associated Companies		
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,038,959,184	15,830,530

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
07/25/96	07/15/26	07/25/96	07/15/26	24,200,000	326,149	3
						4
07/25/96	07/15/26	07/25/96	07/15/26	24,000,000	320,419	5
						6
5/17/00	2/1/27	5/17/00	2/1/07	4,360,000	95,954	7
						8
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	624,173	9
						10
				955,460,000	50,296,260	11
						12
						13
						14
						15
4/26/00	2/1/25			19,885,000		16
						17
02/10/92				11,700,000		18
					21,325	19
				31,585,000	21,325	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				987,045,000	50,317,585	33

Schedule Page: 256 Line No.: 10 Column: h

Redeemed March 2004.

Schedule Page: 256.1 Line No.: 19 Column: h

Redeemed August 2004.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)	70,608,121
2		
3		
4	Taxable Income Not Reported on Books	
5	Footnote 1	28,759,330
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Footnote 2	26,948,526
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Footnote 3	17,526,153
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Footnote 4	35,391,378
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	73,398,445
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	25,689,456
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Schedule Page: 261 Line No.: 5 Column: a

004003-CONSTRUCTION ADV-252	3,414,950
004004-CIAC AS TAXABLE INC CLOSED TO PLANT	23,000,000
004005-AVOIDED COST INT CAP	2,492,873
004013-CIAC TAXABLE INCOME IN ACCT 107	149,933
004016-CIAC TAXABLE INCOME-ACCT 253.575	436,910
004017-JOINT USE FEE REC'D B4 INC BOOKED-253.050	(85,768)
004501-ROYALTY INCOME	109,150
004506-CIAC-MERIDIAN GOLD	(56,560)
004507-CIAC-MICRON-DRAM	(620,846)
004512-CIAC-SEATTLE CITY LIGHT-NEW	$ (81,312)
Total	**28,759,330**

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

Total Federal and State taxes deducted on books	**1,946,525**
005001-BAD DEBT EXPENSE	(102,190)
005008-GAIN/LOSS ON REACQUIRED DEBT-DEFERRED	549,856
005010-SFAS 112-POST-EMPLY BEN 182/253	115,271
005014-OVERACCRUED VACATION-ACCT 242	219,071
005017-INJURIES & DAMAGES	(1,076,005)
005019-DIRECTORS FEES DEF	209,465
005022-CAPITALIZED OVERHEADS	(10,450,000)
005023-PENSION ACCR TO 926200	3,535,000
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	290,000
005025-MILNER FALLING WATER - REV ACCRL	264,100
005027-AMORTIZATION OF ACCOUNT 114	(22,723)
005028-OREGON OPER PROPERTY TAX ADJ	(45,145)
005033-NONVEBA PEN&BEN-Acct 228	(62,291)
005035-PCA EXPENSE DEFERRAL	16,265,811
005039-POST RETIREE BENEFIT- FAS106-ACCT 182	544,800
005042-REV SHOBAN TRANS ROW EXPENSE	869,355
005044-RESTRICTED STOCK PLAN-COMP	452,729
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	5,385,347
005049-253-FERC SETTLEMENT RESERVE	(2,000,000)
005050-186-BAD DEBT RESERVE-FINANCING PRGMS	(25,875)
005051-PUC ORDER 29505 - PROFESSIONAL FEES	(60,166)
005501-SEC PLAN-NET INS COSTS	(521,251)
005502-128-SMSP-MRKT CHG OF RABBI INVSTMNTS	(553,286)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST	(38,370)
005504-NONDEDUCTIBLE POLITICAL EXP-426.4	250,000
005505-SEC PLAN-BENEFIT ACCR	2,130,167
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS	100,000
005518-STARTUP & ORGANIZATION COSTS	(600)
005531-RATE CASE DISALLOWANCES	8,778,931
Total	**26,948,526**

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

007002-GAIN ON SALE OF BOC	31,970
007007-OTHER REGULATORY LIABILITIES-254	1,225,258
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	8,190,247
007502-ALLOWANCE FOR OFUDC	3,904,027
007503-ALLOWANCE FOR BFUDC	2,952,809

007504-RECLASS TAX EXEMPT INTEREST - FED & IDAHO	6,781
007504-RECLASS TAX EXEMPT INTEREST - FED ONLY	234,848
007514-COLI-INSURANCE PROCEEDS	980,213
Total	**17,526,153**

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 165	(1,339,189)
008009-DEPR FOR TAX GT OR LT BOOK	18,059,869
008020-CONSERVATION PROGRAMS	(3,247,604)
008027-NEVADA OPERATING PROPERTY TAX ADJ	(35,729)
008034-REMOVAL COSTS	3,553,551
008035-REPAIR ALLOWANCE	7,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS	(1,672,816)
008039-ST TAX-NOT DEDUCTEDON PRIOR RETURN	44,867
008041-AM FALLS - UNAMORTIZED DEBT EXP	(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT	(643,139)
008045-ST TAX-AUDIT STTLMNTS PAID THIS YR	1,506,827
008057-REORGANIZATION COSTS-ACCT 182	(754,057)
008062-FERC ORDER 2000 COSTS	(307,280)
008071-PHOTOVOLTAIC STARTUP COSTS-ACCT 182	(23,808)
008072-INTANGIBLE ASSET-LABOR DEDUCT-FED ONLY	4,514,000
008074-INCREMENTAL SECURITY COSTS DEDUCTED	(262,929)
008077-PP INS & OTR EXP (1 YR OR LESS)-165	1,181,677
008501-COLI-TAX ADJ FROM BOOKS	(443,137)
008504-OREGON NONOP PROPERTY TAX ADJUST	38
008508-DEPR ADJ - NONOP - OTHER PROPERTY - NEW	8,039
008533-INTEREST ON IRS TAX DEFICIENCIES	2,227,113
0NI0016-DIV PAID DED PUB UTIL	300,000
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	**5,773,084**
Total	**35,391,378**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	42,209,969		16,450,770	33,025,085	
3	Social Security - (FOAB)	1,164		8,357,712	8,020,330	
4	Unemployment	56		138,478	105,011	
5	Subtotal Federal	42,211,189		24,946,960	41,150,426	
6						
7	State of Idaho:					
8	Property	5,935,957		11,675,885	12,298,341	
9	Income	1,358,871		6,824,261	2,469,446	
10	KWH	85,123		1,356,460	1,351,312	
11	Unemployment	30		105,445	97,079	
12	Regulatory Commission			1,642,858	1,642,858	
13	Business License - Sho Ban		150	150	150	
14	Subtotal Idaho	7,379,981	150	21,605,059	17,859,186	
15						
16	State of Oregon					
17	Property		977,919	2,010,196	2,055,379	
18	Income	1,135,775		337,835	524,846	
19	Regulatory Commission			91,460	91,460	
20	Unemployment			25,469	23,701	
21	Franchise	111,677		461,080	452,376	
22	Subtotal Oregon	1,247,452	977,919	2,926,040	3,147,762	
23						
24	State of Montana:					
25	Property	38,746		80,322	78,953	
26	Subtotal Montana	38,746		80,322	78,953	
27						
28	State of Nevada:					
29	Property	238,828	477,657	920,201	902,337	
30	Unemployment			75	66	
31	Business Tax			588	588	
32	Subtotal Nevada	238,828	477,657	920,864	902,991	
33						
34	State of Wyoming					
35	Corporate License			2,719	2,719	
36	Property	483,980		887,007	927,484	
37	Subtotal Wyoming	483,980		889,726	930,203	
38						
39	misc states franchise			-1	-1	
40						
41	TOTAL	52,867,442	1,455,726	42,897,154	64,121,072	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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
25,635,654		16,305,814			144,956	2
338,547		8,357,712				3
33,523		138,478				4
26,007,724		24,802,004			144,956	5
						6
						7
5,313,501		11,675,885				8
5,713,686		6,783,393			40,868	9
90,271		1,356,460				10
8,396		105,445				11
		1,642,858				12
	150	150				13
11,125,854	150	21,564,191			40,868	14
						15
						16
	1,023,101	2,010,196				17
948,764		335,737			2,098	18
		91,460				19
1,768		25,469				20
120,381		461,080				21
1,070,913	1,023,101	2,923,942			2,098	22
						23
						24
40,115	441,929	80,322				25
40,115	441,929	80,322				26
						27
						28
220,963		920,201				29
9		75				30
		588				31
220,972		920,864				32
						33
443,504						34
		2,719				35
		887,007				36
443,504		889,726				37
						38
		-1				39
						40
40,280,158	1,465,180	42,708,532			188,622	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Other States Income	1,267,266		155,362	51,552	
2	Payroll Adjustment			-8,627,178		
3						
4						
5						
6						
7						
8						
9						
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35						
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38						
39						
40						
41	TOTAL	52,867,442	1,455,726	42,897,154	64,121,072	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)	
1,371,076		154,662			700	1
		-8,627,178				2
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40,280,158	1,465,180	42,708,532			188,622	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/22/2005	2004/Q4

FOOTNOTE DATA

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

Account 409.2

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

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

Schedule Page: 262.1 Line No.: 1 Column: l

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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	04/22/2005	End of 2004/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%	1,695,295				154,112	
4	7%						
5	10%	38,137,309				1,932,957	
6		1,455,846				27,084	
7		26,500,527	411.4	2,341,679	411.4	1,180,346	
8	TOTAL	67,788,977		2,341,679		3,294,499	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 col A 11%						
11							
12	State of Idaho	26,500,527	411.4	2,341,679	411.4	1,180,346	
13							
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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	04/22/2005	End of 2004/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
1,541,183	11.00		3
			4
36,204,352	19.73		5
1,428,762	53.75		6
27,661,860	22.45		7
66,836,157			8
			9
			10
			11
27,661,860			12
			13
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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 $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Point to Point Transmission Study	1,185,971	Footnote	5,808,891	5,474,229	851,309
2						
3	FTV		Footnote	866,667	5,133,333	4,266,666
4						
5	FASB 133 Mark to Market	35,110	1823	104,816	69,706	
6						
7	Linden Feeder		N/A		128,831	128,831
8						
9	Joint Pole Use	502,751	Footnote	1,023,505	782,418	261,664
10						
11	Customer Level Pay	3,811,345	142	2,673,265	999,520	2,137,600
12						
13	US Airforce Photovoltaic Generator	135,593	431	161	33,139	168,571
14						
15	Security Plan	23,389,778	232	2,669,833	4,800,000	25,519,945
16						
17	FERC Settlement Reserve	4,000,000	1823	2,000,000		2,000,000
18						
19	Milner Falling Water	2,928,757	N/A		264,100	3,192,857
20						
21	Postretirement Benefits	3,247,131	401	256,237		2,990,894
22						
23	Benefit Plan - Minimum Liability	12,286,612	Footnote	1,696,544		10,590,068
24						
25	Directors Deferred Compensation	3,006,920	232	234,054	443,519	3,216,385
26						
27	Construction Work In Progress	496,010	107	496,010	932,920	932,920
28						
29						
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45						
46						
47	TOTAL	55,025,978		17,829,983	19,061,715	56,257,710

Schedule Page: 269 Line No.: 1 Column: c

400	10,000
232	5,181,323
142	617,568
	5,808,891

Schedule Page: 269 Line No.: 3 Column: c

165	466,667
146	400,000
	866,667

Schedule Page: 269 Line No.: 9 Column: c

400	1,021,900
232	1,605
	1,023,505

Schedule Page: 269 Line No.: 23 Column: c

219	880,135
190	564,960
186	251,449
	1,696,544

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

3. 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
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	220,017,212	16,770,230	11,860,492
3	Gas			
4	Other -- See Note	349,145,406	-2,856,166	-680,052
5	TOTAL (Enter Total of lines 2 thru 4)	569,162,618	13,914,064	11,180,440
6	Non-Operating Property	272,003		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	569,434,621	13,914,064	11,180,440
10	Classification of TOTAL			
11	Federal Income Tax	480,583,747	13,875,512	11,180,440
12	State Income Tax	88,850,875	38,552	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		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
						224,926,950	2
							3
		182	668,961	182	14,055,794	360,356,125	4
			668,961		14,055,794	585,283,075	5
3,143	14,875					260,271	6
							7
							8
3,143	14,875		668,961		14,055,794	585,543,346	9
							10
2,636	12,478		656,586		11,669,031	494,281,422	11
506	2,397		12,276		2,386,763	91,262,023	12
							13

NOTES (Continued)

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report 2004/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 4 Column: a

		Changes during Year				Adjustments Debits		Adjustments Credits		
	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Repair Allowance	391,585		169,200							222,385
Bridger	529,657		102,400							427,257
N. Valmy	963,266		76,500							886,766
FERC Jurisdictional	7,705,967	112,535								7,818,502
Taxable CIAC in CWIP Bal.	(2,651,298)	273,742	(854,549)							(1,523,007)
CIAC Taxable Income-Acct 253.575	(173,604)	(326,522)	(173,604)							(326,522)
Misc Software Develop Costs	469,284	(314,313)	-							154,971
Intangible Asset-Labor Deduction	11,077,806	(2,601,608)								8,476,198
FASB 109	330,832,743					182	668,961	182	14,055,794	344,219,575
	349,145,406	(2,856,166)	(680,052)	-	-		668,961		14,055,794	360,356,125

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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				
4				
5	Ferc Order 144A	-941,979		133,158
6				
7				
8	Other -- See Note	39,860,769	12,257,454	23,181,640
9	TOTAL Electric (Total of lines 3 thru 8)	38,918,790	12,257,454	23,314,798
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	404,571		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	39,323,361	12,257,454	23,314,798
20	Classification of TOTAL			
21	Federal Income Tax	32,841,872	10,282,215	19,579,171
22	State Income Tax	6,481,489	1,975,239	3,735,627
23	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
						-1,075,137	5
							6
							7
		219	39,552	219	852	28,897,883	8
			39,552		852	27,822,746	9
							10
							11
							12
							13
							14
							15
							16
							17
26,331	43,196					387,706	18
26,331	43,196		39,552		852	28,210,452	19
							20
22,087	36,235		39,552			23,491,216	21
4,243	6,961				852	4,719,235	22
							23

NOTES (Continued)

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FOOTNOTE DATA

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

	Changes during Year				Adjustments Debits		Adjustments Credits		
	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Loss on Reacquired Debt	841,951		1,856,565							(1,014,614)
Conservation Programs	8,310,361		1,338,017							6,972,343
PCA Expense Deferral	22,204,211	11,826,688	18,185,807							15,845,093
PV Startup Costs	10,083	-	9,308							776
Post Retiree Benefits	230,739	-	212,990							17,749
Reorganization Costs	589,596	-	294,799							294,798
Incremental Security Costs	420,703	(20,552)	82,240							317,911
FERC Order 2000 Costs	1,000,204	173,228	293,359							880,073
Oregon Excess Power Costs	5,324,861	250,800	904,787							4,670,874
Professional Fees - IPUC Order 29505	-	27,290	3,768							23,522
Unrealized gains on Mkt Securities	928,058					219	39,552	219	852	889,358
	39,860,769	12,257,454	23,181,640	-	-		39,552		852	28,897,883

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

		Changes during Year				Adjustments Debits		Adjustments Credits		
	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Advance Coal Royalties Oregon	399,113			10,791	42,672					367,232

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FOOTNOTE DATA

Non-Op Prop Tax Adj	805			15	0			820
Unrealized Gain/Loss From Rabbit Trust	4,653			15,524	523			19,653
	404,571	-	-	26,330	43,196	-	-	387,706

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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 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		175	664,206	751,713	87,507
2						
3	Idaho 1999 - NEEA (Nw energy efficiency act)	1,183,291	232	1,201,815	5,484	-13,040
4						
5	Demand Side Management Rider 29026	3,273,891	Footnote	1,928,575	3,468,406	4,813,722
6						
7	FAS133 Market to Market		175	687,603	687,603	
8						
9	BPA Credit-Residential - Idaho	1,077,901	Footnote	12,380,060	12,535,595	1,233,436
10						
11	BPA Credit-Residential - Oregon	51,196	Footnote	545,246	534,990	40,940
12						
13	BPA Credit-Farm - Idaho	580,788	131	2,447,216	2,409,284	542,856
14						
15	BPA Credit-Farm - Oregon	24,802	142	101,630	92,958	16,130
16						
17	BPA Credit - Conservation	653,139	Footnote	1,195,714	798,541	255,966
18						
19	Pre94 Demand Side Management Order	177,534	1823	44,160	15,233	148,607
20						
21	IPUC Order 29600		Footnote	24,929,167	38,600,000	13,670,833
22						
23	OPUC Order 04-283		N/A		100,000	100,000
24						
25	Boise Operation Center	93,247	Footnote	31,970		61,277
26						
27	Unfunded Accumulated Deferred Income Tax	41,023,911	190	576,619		40,447,292
28						
29	Asset Retirement Oblication - Removal Cost	142,594,975	N/A		5,104,848	147,699,823
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	190,734,675		46,733,981	65,104,655	209,105,349

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FOOTNOTE DATA

Schedule Page: 278 Line No.: 5 Column: c

131	461,890
142	246,508
154	72,235
184	616
232	1,124,982
921	8,069
253	473
254	13,803
	1,928,575

Schedule Page: 278 Line No.: 9 Column: c

131	6,925
142	12,373,134
	12,380,060

Schedule Page: 278 Line No.: 11 Column: c

131	172
142	545,075
	545,246

Schedule Page: 278 Line No.: 17 Column: c

131	204
154	12,858
158	145
232	1,176,448
254	6,059
	1,195,714

Schedule Page: 278 Line No.: 21 Column: c

1823	5,637,208
401	19,291,958
	24,929,167

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FOOTNOTE DATA

Schedule Page: 278 Line No.: 25 Column: c

163	
	320
401	
	21,740
402	
	9,910
	31,970

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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.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	274,313,240	275,919,849
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	247,425,040	263,803,176
5	Large (or Ind.) (See Instr. 4)	111,797,200	128,619,992
6	(444) Public Street and Highway Lighting	2,300,038	2,625,742
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	635,835,518	670,968,759
11	(447) Sales for Resale	121,147,646	71,572,857
12	TOTAL Sales of Electricity	756,983,164	742,541,616
13	(Less) (449.1) Provision for Rate Refunds	-1,114,364	1,514,466
14	TOTAL Revenues Net of Prov. for Refunds	758,097,528	741,027,150
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,214,833	3,391,006
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	18,085,801	17,529,569
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	20,423,944	18,433,937
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	42,724,578	39,354,512
27	TOTAL Electric Operating Revenues	800,822,106	780,381,662

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,580,337	4,426,976	360,462	349,219	2
				3
5,296,407	5,317,441	72,382	70,691	4
3,334,955	3,206,182	120	115	5
27,890	29,432	501	414	6
				7
				8
				9
13,239,589	12,980,031	433,465	420,439	10
2,885,350	1,829,940			11
16,124,939	14,809,971	433,465	420,439	12
				13
16,124,939	14,809,971	433,465	420,439	14

Line 12, column (b) includes $ 2,929,513 of unbilled revenues.

Line 12, column (d) includes 54,757 MWH relating to unbilled revenues

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	4,546,209	271,359,665	360,462	12,612	0.0597
3	03 - Residential-Mastered Metere					
4	84 - Residential-Net Metering					
5	15 - Dusk to dawn lighting	2,427	524,019			0.2159
6	Unbilled Revenues	31,701	2,429,556			0.0766
7	Total 440	4,580,337	274,313,240	360,462	12,707	0.0599
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	305,861	22,109,466	35,821	8,539	0.0723
11	09 - General service	3,201,323	137,762,375	18,161	176,275	0.0430
12	10 - Large power winter service					
13	84 - General Service - Net Meter					
14	15 - Dusk to dawn lighting	3,787	730,598			0.1929
15	19 - Uniform rate contracts	2,268,266	79,921,273	117	19,386,889	0.0352
16	21 - Interruptible irrigation					
17	22 - Limited use Prairie Power					
18	24 - Irrigation Pumping	1,703,587	82,842,092	17,164	99,253	0.0486
19	25 - Irrigation Pumping -Time of	59,364	2,810,854	142	418,056	0.0473
20	40 - General service	14,590	877,776	1,094	13,336	0.0602
21	Commercial & Industrial & Unbill	1,074,584	32,167,806	3	358,194,667	0.0299
22	Total 442	8,631,362	359,222,240	72,502	119,050	0.0416
23						
24	444 - Public Street Lighting:					
25	32 - Shielded Streel Lighting	15	3,152	1	15,000	0.2101
26	40 - General service	1,236	74,412	290	4,262	0.0602
27	41 - Street lighting	17,637	1,890,911	138	127,804	0.1072
28	42 - Traffic control lighting	9,002	331,563	72	125,028	0.0368
29						
30	Total 444	27,890	2,300,038	501	55,669	0.0825
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,184,832	632,906,005	433,465	30,417	0.0480
42	Total Unbilled Rev.(See Instr. 6)	54,757	2,929,513	0	0	0.0535
43	TOTAL	13,239,589	635,835,518	433,465	30,544	0.0480

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SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Raft River Rural Electric	RQ	V6-44	8.869	8.869	7.768
2	City of Weiser	RQ	V6-52	9.037	8.996	8.334
3	American Electric Power Service Cor	SF	WSPP	0.000	0.000	0.000
4	Arizona Public Service Co.	OS	WSPP	0.000	0.000	0.000
5	Arizona Public Service Co.	SF	WSPP	0.000	0.000	0.000
6	Avista Corp. - WWP Div.	OS	WSPP	0.000	0.000	0.000
7	Avista Corp. - WWP Div.	SF	WSPP	0.000	0.000	0.000
8	Avista Energy, Inc.	OS	WSPP	0.000	0.000	0.000
9	Avista Energy, Inc.	SF	WSPP	0.000	0.000	0.000
10	Benton County PUD	OS	WSPP	0.000	0.000	0.000
11	Black Hills Power Inc.	OS	WSPP	0.000	0.000	0.000
12	Black Hills Power Inc.	SF	WSPP	0.000	0.000	0.000
13	Bonneville Power Administration	OS	WSPP	0.000	0.000	0.000
14	Bonneville Power Administration	SF	WSPP	0.000	0.000	0.000
	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.
53,680	164,103	1,137,213	3,000	1,304,316	1
50,651	401,228	1,254,579	339,882	1,995,689	2
92,800		3,954,600		3,954,600	3
14,927		754,985		754,985	4
657,695		27,388,720		27,388,720	5
100		3,100		3,100	6
4,400		191,700		191,700	7
1,158		42,005		42,005	8
2,200		82,700		82,700	9
604		20,340		20,340	10
2,108		85,680		85,680	11
11,215		451,273		451,273	12
40,937		1,508,660		1,508,660	13
114,084		4,487,265		4,487,265	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	BP Energy Company	OS	WSPP	0.000	0.000	0.000
2	BP Energy Company	SF	WSPP	0.000	0.000	0.000
3	Burbank, City of	SF	WSPP	0.000	0.000	0.000
4	Calpine Energy Services, L.P.	OS	WSPP	0.000	0.000	0.000
5	Calpine Energy Services, L.P.	SF	WSPP	0.000	0.000	0.000
6	Cargill Power Markets LLC	OS	WSPP	0.000	0.000	0.000
7	Cargill Power Markets LLC	SF	WSPP	0.000	0.000	0.000
8	Chelan Co PUD	OS	WSPP	0.000	0.000	0.000
9	Chelan Co PUD	SF	WSPP	0.000	0.000	0.000
10	Clatskanie PUD	OS	WSPP	0.000	0.000	0.000
11	Clatskanie PUD	SF	WSPP	0.000	0.000	0.000
12	Colton, City of	LF	84	0.000	0.000	0.000
13	Conoco Phillips Company	OS	WSPP	0.000	0.000	0.000
14	Conoco Phillips Company	SF	WSPP	0.000	0.000	0.000
	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.
150		4,680		4,680	1
20,800		897,700		897,700	2
400		17,700		17,700	3
2,070		65,853		65,853	4
2,800		112,750		112,750	5
1,396		47,614		47,614	6
105,922		4,434,090		4,434,090	7
1,069		34,525		34,525	8
200		7,400		7,400	9
249		9,652		9,652	10
200		7,000		7,000	11
19,354		570,036		570,036	12
732		15,034		15,034	13
3,200		168,600		168,600	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Constellation Energy Commodities Gr	SF	WSPP	0.000	0.000	0.000
2	Constellation Power Source, Inc.	OS	WSPP	0.000	0.000	0.000
3	Constellation Power Source, Inc.	SF	WSPP	0.000	0.000	0.000
4	Coral Power, LLC	OS	WSPP	0.000	0.000	0.000
5	Coral Power, LLC	SF	WSPP	0.000	0.000	0.000
6	El Paso Electric Company	OS	WSPP	0.000	0.000	0.000
7	ENMAX Energy Marketing Inc.	OS	WSPP	0.000	0.000	0.000
8	ENMAX Energy Marketing Inc.	SF	WSPP	0.000	0.000	0.000
9	Entergy-Koch Trading, LP	SF	WSPP	0.000	0.000	0.000
10	Eugene Water & Electric Board	OS	WSPP	0.000	0.000	0.000
11	Eugene Water & Electric Board	SF	WSPP	0.000	0.000	0.000
12	Franklin County P.U.D.	OS	WSPP	0.000	0.000	0.000
13	Grant County P.U.D.	OS	WSPP	0.000	0.000	0.000
14	Grays Harbor PUD	OS	WSPP	0.000	0.000	0.000
	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	04/22/2005	End of 2004/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.
12,800		707,050		707,050	1
608		22,077		22,077	2
25,000		1,160,720		1,160,720	3
48		2,184		2,184	4
83,600		3,390,650		3,390,650	5
10		320		320	6
4		208		208	7
1,600		56,200		56,200	8
15,200		515,700		515,700	9
3,123		113,214		113,214	10
10,560		363,330		363,330	11
167		3,875		3,875	12
1,943		93,167		93,167	13
533		12,569		12,569	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	J. Aron & Company	SF	WSPP	0.000	0.000	0.000
2	Morgan Stanley Capital Group Inc.	OS	WSPP	0.000	0.000	0.000
3	Morgan Stanley Capital Group Inc.	SF	WSPP	0.000	0.000	0.000
4	Northern California Power Agency	SF	WSPP	0.000	0.000	0.000
5	NorthWestern Energy, L.L.C.	IF	V6-51	0.000	0.000	0.000
6	Pacific Northwest Generating Cooper	OS	WSPP	0.000	0.000	0.000
7	Pacific Northwest Generating Cooper	SF	WSPP	0.000	0.000	0.000
8	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
9	PacifiCorp Inc.	SF	WSPP	0.000	0.000	0.000
10	Portland General Electric Company	OS	WSPP	0.000	0.000	0.000
11	Portland General Electric Company	SF	WSPP	0.000	0.000	0.000
12	Powerex Corp.	OS	WSPP	0.000	0.000	0.000
13	Powerex Corp.	SF	WSPP	0.000	0.000	0.000
14	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,600		60,800		60,800	1
3,362		141,145		141,145	2
285,781		12,217,078		12,217,078	3
1,033		54,316		54,316	4
44,231		1,972,815	3,307,830	5,280,645	5
1,885		59,822		59,822	6
5,000		217,450		217,450	7
12,522		502,047		502,047	8
62,767		2,809,850		2,809,850	9
60,415		2,217,726		2,217,726	10
95,775		3,718,382		3,718,382	11
50,445		1,765,915		1,765,915	12
371,900		15,079,120		15,079,120	13
3,535		130,263		130,263	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PPL Montana, LLC	SF	WSPP	0.000	0.000	0.000
2	PPM Energy, Inc.	OS	WSPP	0.000	0.000	0.000
3	PPM Energy, Inc.	SF	WSPP	0.000	0.000	0.000
4	Public Service Co. of Colorado	OS	WSPP	0.000	0.000	0.000
5	Public Service Co. of Colorado	SF	WSPP	0.000	0.000	0.000
6	Public Service Company of New Mexic	OS	WSPP	0.000	0.000	0.000
7	Public Service Company of New Mexic	SF	WSPP	0.000	0.000	0.000
8	Puget Sound Energy, Inc.	OS	WSPP	0.000	0.000	0.000
9	Puget Sound Energy, Inc.	SF	WSPP	0.000	0.000	0.000
10	Rainbow Energy Marketing Corporatio	OS	WSPP	0.000	0.000	0.000
11	Rainbow Energy Marketing Corporatio	SF	WSPP	0.000	0.000	0.000
12	San Diego Gas and Electric	SF	WSPP	0.000	0.000	0.000
13	Seattle City Light	OS	WSPP	0.000	0.000	0.000
14	Seattle City Light	SF	WSPP	0.000	0.000	0.000
	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.
9,600		472,031		472,031	1
619		20,288		20,288	2
56,600		2,289,500		2,289,500	3
5,452		209,527		209,527	4
20,000		910,920		910,920	5
981		39,800		39,800	6
12,000		551,480		551,480	7
25		1,125		1,125	8
5,600		219,200		219,200	9
75		3,825		3,825	10
13,520		530,700		530,700	11
800		30,600		30,600	12
11,131		423,855		423,855	13
6,800		278,600		278,600	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Sempra Energy Trading Corporation	OS	WSPP	0.000	0.000	0.000
2	Sempra Energy Trading Corporation	SF	WSPP	0.000	0.000	0.000
3	Sierra Pacific Power Company	OS	WSPP	0.000	0.000	0.000
4	Snohomish County PUD	OS	WSPP	0.000	0.000	0.000
5	Snohomish County PUD	SF	WSPP	0.000	0.000	0.000
6	Tacoma Power	OS	WSPP	0.000	0.000	0.000
7	Tractebel Energy Marketing, Inc.	OS	WSPP	0.000	0.000	0.000
8	Tractebel Energy Marketing, Inc.	SF	WSPP	0.000	0.000	0.000
9	TransAlta Energy Marketing (U.S.) I	OS	WSPP	0.000	0.000	0.000
10	TransAlta Energy Marketing (U.S.) I	SF	WSPP	0.000	0.000	0.000
11	Tri-State Generation and Transmissi	OS	WSPP	0.000	0.000	0.000
12	Utah Associated Municipal Power Sys	OS	WSPP	0.000	0.000	0.000
13	Utah Associated Municipal Power Sys	SF	WSPP	0.000	0.000	0.000
14	Utah Municipal Power Agency	SF	V6-18	0.000	0.000	0.000
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,293		52,864		52,864	1
250,674		10,398,059		10,398,059	2
75		7,125		7,125	3
6,409		244,625		244,625	4
400		4,800		4,800	5
30		620		620	6
3,364		157,368		157,368	7
30,520		1,071,870		1,071,870	8
6,594		280,379		280,379	9
72,600		3,126,050		3,126,050	10
2,329		87,843		87,843	11
6,061		320,782		320,782	12
1,120		47,520		47,520	13
80		4,400		4,400	14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Western Area Power Administration	OS	WSPP	0.000	0.000	0.000
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.
50		2,400		2,400	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
104,331	565,331	2,391,792	342,882	3,300,005	
2,781,019	0	114,539,811	3,307,830	117,847,641	
2,885,350	**565,331**	**116,931,603**	**3,650,712**	**121,147,646**	

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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	04/22/2005	2004/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: j

Customer Charge

Schedule Page: 310 Line No.: 2 Column: j

Network transmission charges

Schedule Page: 310.3 Line No.: 5 Column: j

Capacity and penalty charge

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,187,136	861,643
5	(501) Fuel	98,387,370	94,223,588
6	(502) Steam Expenses	5,333,426	4,617,830
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,558,515	1,306,920
10	(506) Miscellaneous Steam Power Expenses	5,868,516	3,533,153
11	(507) Rents	710,713	576,580
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	113,045,676	105,119,714
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,859,869	2,029,957
16	(511) Maintenance of Structures	358,798	323,838
17	(512) Maintenance of Boiler Plant	12,665,232	12,467,878
18	(513) Maintenance of Electric Plant	5,182,203	5,682,227
19	(514) Maintenance of Miscellaneous Steam Plant	3,076,141	5,374,982
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,142,243	25,878,882
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	137,187,919	130,998,596
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	4,421,651	3,825,351
45	(536) Water for Power	4,016,995	3,796,233
46	(537) Hydraulic Expenses	6,792,153	5,615,743
47	(538) Electric Expenses	1,245,717	1,133,793
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,528,085	1,824,092
49	(540) Rents	379,919	374,008
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	19,384,520	16,569,220

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,058,293	1,134,906
54	(542) Maintenance of Structures	1,004,778	1,187,642
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,032,152	795,499
56	(544) Maintenance of Electric Plant	2,268,044	2,608,366
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,642,221	2,236,821
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,005,488	7,963,234
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	27,390,008	24,532,454
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	391,835	476,255
63	(547) Fuel	4,874,063	5,674,170
64	(548) Generation Expenses	170,854	162,122
65	(549) Miscellaneous Other Power Generation Expenses	298,934	302,448
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,735,686	6,614,995
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	230	
70	(552) Maintenance of Structures	123,893	151,970
71	(553) Maintenance of Generating and Electric Plant	69,240	127,718
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	240,994	289,779
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	434,357	569,467
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,170,043	7,184,462
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	195,642,193	150,979,849
77	(556) System Control and Load Dispatching	106,362	24,902
78	(557) Other Expenses	41,082,749	72,250,173
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	236,831,304	223,254,924
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	407,579,274	385,970,436
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,031,371	1,615,056
84	(561) Load Dispatching	2,909,482	2,788,312
85	(562) Station Expenses	1,686,223	1,546,777
86	(563) Overhead Lines Expenses	544,172	656,409
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	8,441,863	5,424,722
89	(566) Miscellaneous Transmission Expenses	17,854	284,850
90	(567) Rents	2,176,624	1,399,624
91	TOTAL Operation (Enter Total of lines 83 thru 90)	17,807,589	13,715,750
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	653,160	739,753
94	(569) Maintenance of Structures		337
95	(570) Maintenance of Station Equipment	3,009,973	2,679,028
96	(571) Maintenance of Overhead Lines	2,356,489	2,298,159
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	7,878	79,716
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	6,027,500	5,796,993
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	23,835,089	19,512,743
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,608,681	3,341,973

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	2,395,937	2,231,796
106	(582) Station Expenses	950,120	853,609
107	(583) Overhead Line Expenses	3,481,870	3,369,643
108	(584) Underground Line Expenses	1,670,619	2,818,655
109	(585) Street Lighting and Signal System Expenses	151,313	128,348
110	(586) Meter Expenses	4,127,933	4,722,236
111	(587) Customer Installations Expenses	545,521	488,959
112	(588) Miscellaneous Expenses	4,997,634	5,753,921
113	(589) Rents	150,421	142,994
114	TOTAL Operation (Enter Total of lines 103 thru 113)	22,080,049	23,852,134
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	66,616	35,636
117	(591) Maintenance of Structures		21
118	(592) Maintenance of Station Equipment	2,932,915	2,863,970
119	(593) Maintenance of Overhead Lines	11,137,680	12,101,013
120	(594) Maintenance of Underground Lines	1,245,264	1,378,903
121	(595) Maintenance of Line Transformers	259,850	1,770,641
122	(596) Maintenance of Street Lighting and Signal Systems	494,696	375,407
123	(597) Maintenance of Meters	953,983	1,425,510
124	(598) Maintenance of Miscellaneous Distribution Plant	178,232	240,673
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	17,269,236	20,191,774
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	39,349,285	44,043,908
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	426,782	399,173
130	(902) Meter Reading Expenses	4,724,432	4,696,330
131	(903) Customer Records and Collection Expenses	9,290,028	8,695,931
132	(904) Uncollectible Accounts	3,009,866	3,957,930
133	(905) Miscellaneous Customer Accounts Expenses	-6,051	126,081
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	17,445,057	17,875,445
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	313,453	402,335
138	(908) Customer Assistance Expenses	7,346,134	7,029,669
139	(909) Informational and Instructional Expenses	5,525	155
140	(910) Miscellaneous Customer Service and Informational Expenses	732,850	631,830
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	8,397,962	8,063,989
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	45,232,476	30,340,516
152	(921) Office Supplies and Expenses	14,719,947	13,579,471
153	(Less) (922) Administrative Expenses Transferred-Credit	26,358,321	28,579,776

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	7,056,785	5,331,006
156	(924) Property Insurance	3,207,907	3,925,932
157	(925) Injuries and Damages	5,996,017	3,900,634
158	(926) Employee Pensions and Benefits	26,676,544	27,781,551
159	(927) Franchise Requirements	2,075	2,725
160	(928) Regulatory Commission Expenses	3,976,930	3,882,273
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	118,315	560,508
163	(930.2) Miscellaneous General Expenses	1,959,515	1,839,679
164	(931) Rents	12,291	39,324
165	TOTAL Operation (Enter Total of lines 151 thru 164)	82,600,481	62,603,843
166	Maintenance		
167	(935) Maintenance of General Plant	2,525,892	2,398,080
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	85,126,373	65,001,923
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	581,733,040	540,468,444

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 & Small Power Producers					
2	Willis and Betty Deveny	LU	-	N/A	N/A	N/A
3	James B. Howell/CHI	LU	-	N/A	N/A	N/A
4	Tamarack Energy Partnership	LU	-	4.942Mw		
5	Owyhee Irrigation District					
6	Mitchell Butte	LU	-	N/A	N/A	N/A
7	Owyhee Dam	LU	-	N/A	N/A	N/A
8	Tunnel #1	LU	-	N/A	N/A	N/A
9	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
10	Clifton E. Jenson	LU	-	.05Mw	(1)	(1)
11	Snake River Pottery	LU	-	N/A	N/A	N/A
12	White Water Ranch	LU	-	N/A	N/A	N/A
13	John R LeMoyne	LU	-	N/A	N/A	N/A
14	David R Snedigar	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
868				55,611		55,611	2
4,271				276,739		276,739	3
41,780			1,576,498	1,301,318		2,877,816	4
							5
5,959				437,610		437,610	6
18,402				1,202,481		1,202,481	7
7,481				691,475		691,475	8
1,474				103,531		103,531	9
265			17,500	5,454		22,954	10
404				25,661		25,661	11
628				39,988		39,988	12
638				34,546		34,546	13
1,287				83,029		83,029	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Mud Creek Hydro, Inc	LU	-	N/A	N/A	N/A
2	Rim View Trout Company	OS	-	N/A	N/A	N/A
3	Curry Cattle Company	LU	-	.084Mw	(1)	(1)
4	Branchflower Company	LU	-	N/A	N/A	N/A
5	Big Wood Canal Company					
6	Black Canyon	LU	-	N/A	N/A	N/A
7	Jim Knight	LU	-	N/A	N/A	N/A
8	Sagebrush	LU	-	N/A	N/A	N/A
9	Fisheries Development	OS	-	N/A	N/A	N/A
10	Shorock Hydro Inc.					
11	Shoshone Cspp	LU	-	N/A	N/A	N/A
12	Shoshone #2	LU	-	N/A	N/A	N/A
13	Rock Creek #1 Joint Venture	LU	-	1.732Mw	(1)	(1)
14	Richard Kaster					
	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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	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.
335				20,309		20,309	1
1,465				49,970		49,970	2
648			26,796	12,092		38,888	3
889				59,125		59,125	4
							5
264				17,896		17,896	6
572				39,917		39,917	7
676				47,271		47,271	8
801				27,501		27,501	9
							10
1,398				99,718		99,718	11
1,242				79,831		79,831	12
8,971			552,508	173,837		726,345	13
							14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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	Box Canyon	LU	-	N/A	N/A	N/A
2	Briggs Creek	LU	-	N/A	N/A	N/A
3	David McCollum	LU	-	N/A	N/A	N/A
4	H.K. Hydro / Mud Creek S & S	LU	-	N/A	N/A	N/A
5	Allan/Vernon Ravenscroft	LU	-	.488Mw	(1)	(1)
6	William Arkoosh	LU	-	N/A	N/A	N/A
7	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
8	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
9	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
10	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
11	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
12	Pigeon Cove Power	LU	-	1.389	(1)	(1)
13	Consolidated Hydro Inc. / Enel		-			
14	GeoBon #2	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.
1,628				103,875		103,875	1
3,698				236,083		236,083	2
768				48,085		48,085	3
1,306				83,070		83,070	4
1,095			155,672	24,490		180,162	5
2,219				163,118		163,118	6
3,602				274,842		274,842	7
2,729				203,304		203,304	8
3,739				251,705		251,705	9
5,422				332,886		332,886	10
6,473				399,580		399,580	11
7,622			486,150	129,946		616,096	12
							13
2,012				150,087		150,087	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Barber Dam	LU	-	N/A	N/A	N/A
2	Rock Creek #2	LU	-	N/A	N/A	N/A
3	Dietrich Drop	LU	-	N/A	N/A	N/A
4	Lowline #2	LU	-	N/A	N/A	N/A
5	Cedar Draw/Little Mac Power Co.	LU	-	N/A	N/A	N/A
6	South Forks Joint Venture (5)	LU	-	N/A	N/A	N/A
7	Little Wood River Irrigation Dis	LU	-	N/A	N/A	N/A
8	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
9	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
10	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
11	Bypass Limited	LU	-	N/A	N/A	N/A
12	SE Hazelton A LP	LU	-	N/A	N/A	N/A
13	Jerry L McMillan	OS	-	N/A	N/A	N/A
14	Lemhi HydroPower Company	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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)	
11,389				544,748		544,748	1
5,125				247,189		247,189	2
9,083				460,867		460,867	3
9,357				462,736		462,736	4
4,777				289,899		289,899	5
24,561				1,667,386		1,667,386	6
3,416				240,426		240,426	7
1,755				107,660		107,660	8
2,769				205,954		205,954	9
1,606				64,626		64,626	10
24,318				1,196,197		1,196,197	11
20,456				962,320		962,320	12
136				4,574		4,574	13
1,134				79,842		79,842	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	J R Simplot Co.	LU	-	N/A	N/A	N/A
2	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
3	City of Boise	LU	-	N/A	N/A	N/A
4	City of Hailey	LU	-	N/A	N/A	N/A
5	City of Pocatello	LU	-	N/A	N/A	N/A
6	Marysville Hydro Partners	LU	-	N/A	N/A	N/A
7	Wilson Power Company	LU	-	N/A	N/A	N/A
8	Hazelton Power Company	LU	-	N/A	N/A	N/A
9	Pristine Springs Inc.	LU	-	N/A	N/A	N/A
10	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
11	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
12	Contractors Power Group Inc.	LU	-	N/A	N/A	N/A
13	Rupert Cogeneration Partners	LU	-	N/A	N/A	N/A
14	Glenns Ferry Cogeneration Partne	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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)	
61,429				2,669,930		2,669,930	1
2,991				182,679		182,679	2
330				19,703		19,703	3
32				2,066		2,066	4
1,661				115,241		115,241	5
42,959				2,514,089		2,514,089	6
23,556				1,490,323		1,490,323	7
20,406				1,292,175		1,292,175	8
855				39,709		39,709	9
24,620				1,134,530		1,134,530	10
40,017				2,485,758		2,485,758	11
3,007				186,252		186,252	12
80,790				4,816,910		4,816,910	13
83,782				5,001,552		5,001,552	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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	Lewandowski Farms	OS	-	N/A	N/A	N/A
2	Tasco - Nampa	OS	-	N/A	N/A	N/A
3	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
4	Pristine Springs Inc #3	OS	-	N/A	N/A	N/A
5	Ted S. Sorenson/Tiber Dam	LU		N/A	N/A	N/A
6	Other Purchased Power					
7	American Electric Power Service	SF	WSPP	N/A	N/A	N/A
8	Anaheim, City of	SF	WSPP	N/A	N/A	N/A
9	Arizona Public Service Co.	OS	WSPP	N/A	N/A	N/A
10	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
11	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
12	Avista Corp. - WWP Div.	SF	WSPP	N/A	N/A	N/A
13	Avista Energy, Inc.	OS	WSPP	N/A	N/A	N/A
14	Avista Energy, Inc.	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.
174				5,883		5,883	1
1,866				66,576		66,576	2
							3
1,516				52,071		52,071	4
24,964				1,129,568		1,129,568	5
							6
112,800				5,031,510		5,031,510	7
20				1,039		1,039	8
8,631				231,414		231,414	9
106,080				4,192,220		4,192,220	10
19,829				838,849		838,849	11
9,815				448,017		448,017	12
35,341				1,418,040		1,418,040	13
16,400				701,950		701,950	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Benton County PUD	OS	WSPP	N/A	N/A	N/A
2	Benton County PUD	SF	WSPP	N/A	N/A	N/A
3	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
4	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
5	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
6	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
7	BP Energy Company	OS	WSPP	N/A	N/A	N/A
8	BP Energy Company	SF	WSPP	N/A	N/A	N/A
9	Burbank, City of	SF	WSPP	N/A	N/A	N/A
10	Calpine Energy Services, L.P.	OS	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	OS	WSPP	N/A	N/A	N/A
13	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
14	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,025				46,605		46,605	1
2,000				80,640		80,640	2
47,261				1,997,215		1,997,215	3
8,515				350,433		350,433	4
49,896				2,192,574		2,192,574	5
287,854				10,365,034		10,365,034	6
50				1,200		1,200	7
81,975				4,003,569		4,003,569	8
200				6,800		6,800	9
1,788				73,576		73,576	10
26,797				1,165,081		1,165,081	11
1,026				32,010		32,010	12
39,670				1,829,445		1,829,445	13
11,203				499,464		499,464	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Clatskanie PUD	OS	WSPP	N/A	N/A	N/A
2	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
3	Conoco Phillips Company	OS	WSPP	N/A	N/A	N/A
4	Constellation Energy Commodities	SF	WSPP	N/A	N/A	N/A
5	Constellation Power Source, Inc.	OS	WSPP	N/A	N/A	N/A
6	Constellation Power Source, Inc.	SF	WSPP	N/A	N/A	N/A
7	Coral Power, LLC	OS	WSPP	N/A	N/A	N/A
8	Coral Power, LLC	SF	WSPP	N/A	N/A	N/A
9	Douglas County PUD	OS	WSPP	N/A	N/A	N/A
10	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
11	El Paso Electric Company	OS	WSPP	N/A	N/A	N/A
12	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
13	ENMAX Energy Marketing Inc.	SF	WSPP	N/A	N/A	N/A
14	Entergy-Koch Trading, LP	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.
140				6,020		6,020	1
1,200				49,100		49,100	2
175				8,339		8,339	3
10,800				605,200		605,200	4
76				3,675		3,675	5
63,130				2,847,133		2,847,133	6
2,251				58,214		58,214	7
167,225				7,271,365		7,271,365	8
385				15,135		15,135	9
3,197				144,870		144,870	10
215				9,343		9,343	11
400				18,400		18,400	12
1,200				60,700		60,700	13
71,600				3,163,200		3,163,200	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	Eugene Water & Electric Board	OS	WSPP	N/A	N/A	N/A
2	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
3	Franklin County P.U.D.	OS	WSPP	N/A	N/A	N/A
4	Franklin County P.U.D.	SF	WSPP	N/A	N/A	N/A
5	Grant County P.U.D.	OS	WSPP	N/A	N/A	N/A
6	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
7	Grays Harbor PUD	OS	WSPP	N/A	N/A	N/A
8	J. Aron & Company	OS	WSPP	N/A	N/A	N/A
9	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
10	Mirant Americas Energy Marketing	SF	WSPP	N/A	N/A	N/A
11	Morgan Stanley Capital Group Inc	OS	WSPP	N/A	N/A	N/A
12	Morgan Stanley Capital Group Inc	SF	WSPP	N/A	N/A	N/A
13	Nevada Power Company	OS	WSPP	N/A	N/A	N/A
14	Nevada Power Company	SF	WSPP	N/A	N/A	N/A
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
655				33,885		33,885	1
6,200				269,550		269,550	2
941				39,903		39,903	3
1,600				72,600		72,600	4
1,698				72,765		72,765	5
800				36,000		36,000	6
1,465				63,722		63,722	7
160				6,920		6,920	8
38,200				1,970,400		1,970,400	9
3,200				146,600		146,600	10
5,402				188,931		188,931	11
567,732				25,969,763		25,969,763	12
9,145				285,685		285,685	13
225				6,750		6,750	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

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	NorthPoint Energy Solutions Inc.	OS	WSPP	N/A	N/A	N/A
2	NorthWestern Energy, L.L.C.	SF	WSPP	N/A	N/A	N/A
3	NorthWestern Energy, L.L.C.	OS	WSPP	N/A	N/A	N/A
4	NorthWestern Energy, L.L.C.	IF	V6-51	N/A	N/A	N/A
5	Okanogan County P.U.D.	OS	WSPP	N/A	N/A	N/A
6	Pacific Northwest Generating Coo	OS	WSPP	N/A	N/A	N/A
7	Pacific Northwest Generating Coo	SF	WSPP	N/A	N/A	N/A
8	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
9	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
10	Portland General Electric Compan	OS	WSPP	N/A	N/A	N/A
11	Portland General Electric Compan	SF	WSPP	N/A	N/A	N/A
12	Powerex Corp.	OS	WSPP	N/A	N/A	N/A
13	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
14	PPL Montana, LLC	LF	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		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)	
135				5,805		5,805	1
3,360				122,960		122,960	2
424				16,825		16,825	3
48,457				1,930,867		1,930,867	4
160				3,380		3,380	5
1,030				50,065		50,065	6
800				32,400		32,400	7
84,244				4,048,513		4,048,513	8
59,121				2,556,975		2,556,975	9
27,570				1,196,803		1,196,803	10
186,906				6,973,972		6,973,972	11
17,888				985,415		985,415	12
161,803				7,689,020		7,689,020	13
79,872				3,554,304		3,554,304	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PPL Montana, LLC	OS	WSPP	N/A	N/A	N/A
2	PPL Montana, LLC	SF	WSPP	N/A	N/A	N/A
3	PPM Energy, Inc.	OS	WSPP	N/A	N/A	N/A
4	PPM Energy, Inc.	SF	WSPP	N/A	N/A	N/A
5	Public Service Co. of Colorado	OS	WSPP	N/A	N/A	N/A
6	Public Service Co. of Colorado	SF	WSPP	N/A	N/A	N/A
7	Public Service Company of New Me	OS	WSPP	N/A	N/A	N/A
8	Public Service Company of New Me	SF	WSPP	N/A	N/A	N/A
9	Puget Sound Energy, Inc.	OS	WSPP	N/A	N/A	N/A
10	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
11	Rainbow Energy Marketing Corpora	OS	WSPP	N/A	N/A	N/A
12	Rainbow Energy Marketing Corpora	SF	WSPP	N/A	N/A	N/A
13	Rocky Mountain Generation	OS	WSPP	N/A	N/A	N/A
14	Salt River Project	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		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)	
36,535				1,499,706		1,499,706	1
115,896				4,738,991		4,738,991	2
24,248				953,382		953,382	3
80,375				3,603,731		3,603,731	4
1,885				73,420		73,420	5
20,400				867,400		867,400	6
19,941				755,811		755,811	7
2,800				96,160		96,160	8
4,954				206,418		206,418	9
18,990				803,919		803,919	10
16,585				639,604		639,604	11
31,948				1,297,140		1,297,140	12
136				4,128		4,128	13
5,516				267,166		267,166	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Seattle City Light	OS	WSPP	N/A	N/A	N/A
2	Seattle City Light	SF	WSPP	N/A	N/A	N/A
3	Sempra Energy Trading Corporatio	OS	WSPP	N/A	N/A	N/A
4	Sempra Energy Trading Corporatio	SF	WSPP	N/A	N/A	N/A
5	Sierra Pacific Power Company	OS	WSPP	N/A	N/A	N/A
6	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
7	Silicon Valley Power	SF	WSPP	N/A	N/A	N/A
8	Snohomish County PUD	OS	WSPP	N/A	N/A	N/A
9	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
10	Tacoma Power	OS	WSPP	N/A	N/A	N/A
11	Tacoma Power	SF	WSPP	N/A	N/A	N/A
12	Tractebel Energy Marketing, Inc.	OS	WSPP	N/A	N/A	N/A
13	Tractebel Energy Marketing, Inc.	SF	WSPP	N/A	N/A	N/A
14	TransAlta Energy Marketing (U.S.	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.
14,145				579,471		579,471	1
12,521				518,749		518,749	2
1,495				121,095		121,095	3
399,594				18,403,480		18,403,480	4
4,943				338,595		338,595	5
3,619				174,569		174,569	6
800				35,600		35,600	7
6,695				297,861		297,861	8
5,800				260,500		260,500	9
3,155				134,425		134,425	10
4,201				174,152		174,152	11
3,741				164,957		164,957	12
29,600				1,297,550		1,297,550	13
11,485				466,043		466,043	14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing (U.S.	SF	WSPP	N/A	N/A	N/A
2	TransCanada Power	OS	WSPP	N/A	N/A	N/A
3	Tri-State Generation and Transmi	OS	WSPP	N/A	N/A	N/A
4	Turlock Irrigation District	OS	WSPP	N/A	N/A	N/A
5	Utah Associated Municipal Power	OS	WSPP	N/A	N/A	N/A
6	Western Area Power Administratio	OS	WSPP	N/A	N/A	N/A
7	Anaheim, City of	EX	WSPP			
8	Morgan Stanley Capital Group Inc	EX	WSPP			
9	Puget Sound Energy, Inc.	EX	WSPP			
10	Sierra Pacific Power Company	EX	WSPP			
11	Bonneville Power Administration	EX	-			
12	NorthWestern Energy, L.L.C.	EX	-			
13	PacifiCorp Inc.	EX	-			
14	Sierra Pacific Power Company	EX	-			
	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.
195,400				8,630,550		8,630,550	1
467				19,579		19,579	2
2,775				99,518		99,518	3
135				4,995		4,995	4
1,760				60,058		60,058	5
105				3,045		3,045	6
	102,470	87,860					7
	2,240	2,240					8
	37	38					9
	13,922	13,922					10
	52,136	9,477					11
		4,869					12
	35,125	220,826					13
		12,034					14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	Other Transactions					
2	Acctg Valuation of Anaheim,					
3	City of Exchange					
4	Power Exchanges					
5						
6						
7						
8	All statistical classification of OS					
9	is Non-Firm Purhcases.					
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
							2
							3
					111,724	111,724	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,259,876	205,930	351,266	2,815,124	192,715,345	111,724	195,642,193	

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Schedule Page: 326 Line No.: 4 Column: a

The Tamarak Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Company. The actual demand is not used in tetermining the cost of energy.

Schedule Page: 326 Line No.: 4 Column: e

unavailable

Schedule Page: 326 Line No.: 4 Column: f

unavailable

Schedule Page: 326.4 Line No.: 6 Column: a

Ida-West, a subsidiary of IdaCorp, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 7 Column: a

Ida-West, a subsidiary of IdaCorp, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 8 Column: a

Ida-West a subsidiary of IdaCorp has partial ownership of these projects.

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

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

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

Scheduled losses not removed with loss transactions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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 - OT	Bonneville Power Administratio	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - US	Bonneville Power Administratio	United States Bureau of Reclama	FNO
3	Bonneville Power Administration - Ra	Bonneville Power Administratio	Raft River Electric Co-op	FNO
4	Bonneville Power Administration - PF	Bonneville Power Administratio	Priority Firm Customers	FNO
5	Bonneville Power Administration - Vi	Bonneville Power Administratio	Vigilante	OLF
6	Milner Irrigation District	United States Bureau of Reclam	Milner Irrigation District	OLF
7	City of Seattle	Seattle City Light	Bonneville Power Administration	OLF
8	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
9	United States Bureau of Indian Affai	Bonneville Power Administratio	United States Bureau of Indian	AD
10	PacifiCorp	PacifiCorp West	PacifiCorp West	OLF
11	PacifiCorp	PacifiCorp West	PacifiCorp West	OLF
12	PacifiCorp	PacificCorp East	PacifiCorp West	OLF
13	Arizona Public Service	PacifiCorp East	Bonneville Power Administration	NF
14	Arizona Public Service	PacifiCorp East	Avista	NF
15	Arizona Public Service	PacifiCorp East	Sierra Pacific Power	NF
16	Arizona Public Service	Bonneville Power Administratio	PacifiCorp East	NF
17	Boneville Power Administration	Avista	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5				259,381	259,381	1
5				-186,714	-186,714	2
5				214,992	214,992	3
5				700,151	700,151	4
5	Bannack Tap	Vigilante Electric				5
0	Minidoka, Idaho	Various in Idaho		6,927	6,927	6
0	LYPK	LGBP		2,767		7
5				-2,160	-2,160	8
0	LaGrande, Orego	Various in Idaho		15,493	15,493	9
0	JBSN	ENPR		196,200	196,200	10
0	JBSN	ENPR		11,989	11,989	11
0	BOBR	JBSN		253,761	253,761	12
5	BOBR	LGBP		12,000	12,000	13
5	BOBR	LOLO		8,725	8,725	14
5	BOBR	M345		224,400	224,400	15
5	LGBP	BOBR		13,900	13,900	16
5	LOLO	M345		812	812	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	NF
2	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	NF
3	Cargill Power Markets	PacifiCorp East	Avista	NF
4	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	NF
5	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
6	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
7	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
8	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
10	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
11	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	NF
12	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
13	Cargill Power Markets	Bonneville Power Administratio	PacifiCorp East	NF
14	Cargill Power Markets	Bonneville Power Administratio	PacifiCorp West	NF
15	Cargill Power Markets	Bonneville Power Administratio	Sierra Pacific Power	NF
16	Cargill Power Markets	Avista	PacifiCorp East	NF
17	Cargill Power Markets	Avista	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BOBR	HTSP		175	175	1
5	BOBR	LGBP		10,561	10,561	2
5	BOBR	LOLO		40	40	3
5	BOBR	M345		2,950	2,950	4
5	ENPR	BOBR		97,856	97,856	5
5	ENPR	JBSN		813	813	6
5	ENPR	M345		9,215	9,215	7
5	HTSP	BOBR		25	25	8
5	HTSP	M345		2,352	2,352	9
5	JBSN	BOBR		4,200	4,200	10
5	JBSN	LGBP		46,140	46,140	11
5	JBSN	M345		42,261	42,261	12
5	LGBP	BOBR		5,519	5,519	13
5	LGBP	JBSN		300	300	14
5	LGBP	M345		40,294	40,294	15
5	LOLO	BOBR		4,133	4,133	16
5	LOLO	M345		1,198	1,198	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Cargill Power Markets	Sierra Pacific Power	PacifiCorp East	NF
2	J. Aron - Goldman Sachs	PacifiCorp East	Bonneville Power Administration	NF
3	J. Aron - Goldman Sachs	PacifiCorp East	Sierra Pacific Power	NF
4	J. Aron - Goldman Sachs	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
5	J. Aron - Goldman Sachs	Bonneville Power Administratio	PacifiCorp East	NF
6	J. Aron - Goldman Sachs	Bonneville Power Administratio	Sierra Pacific Power	NF
7	J. Aron - Goldman Sachs	Avista	Sierra Pacific Power	NF
8	J. Aron - Goldman Sachs	Sierra Pacific Power	PacifiCorp East	NF
9	J. Aron - Goldman Sachs	Sierra Pacific Power	PacifiCorp West	NF
10	J. Aron - Goldman Sachs	Sierra Pacific Power	Bonneville Power Administration	NF
11	Morgan Stanley Capital Group	PacifiCorp East	NorthWestern/PacifiCorp East	NF
12	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group	PacifiCorp East	Avista	NF
14	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
15	Morgan Stanley Capital Group	PacifiCorp West	PacifiCorp East	NF
16	Morgan Stanley Capital Group	PacifiCorp West	Sierra Pacific Power	NF
17	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	M345	BOBR		400	400	1
5	BOBR	LGBP		47	47	2
5	BOBR	M345		1,017	1,017	3
5	HTSP	M345		352	352	4
5	LGBP	BOBR		82	82	5
5	LGBP	M345		2,822	2,822	6
5	LOLO	M345		326	326	7
5	M345	BOBR		40	40	8
5	M345	ENPR		25	25	9
5	M345	LGBP		770	770	10
5	BOBR	HTSP		192	192	11
5	BOBR	LGBP		9,846	9,846	12
5	BOBR	LOLO		304	304	13
5	BOBR	M345		84,610	84,610	14
5	ENPR	BOBR		456	456	15
5	ENPR	M345		1,876	1,876	16
5	HTSP	M345		2,852	2,852	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group	Bonneville Power Administratio	Sierra Pacific Power	NF
2	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
3	Morgan Stanley Capital Group	Avista	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group	Seattle City Light	PacifiCorp East	NF
5	Morgan Stanley Capital Group	Seattle City Light	NorthWestern/PacifiCorp East	NF
6	Morgan Stanley Capital Group	Seattle City Light	Bonneville Power Administration	NF
7	Morgan Stanley Capital Group	Seattle City Light	Sierra Pacific Power	NF
8	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
9	Pacificorp Power Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
11	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
12	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
13	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
14	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
15	Pacificorp Power Marketing	Bonneville Power Administratio	PacifiCorp East	NF
16	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
17	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5	LGBP	M345		1,974	1,974	1
5	LOLO	BOBR		2,304	2,304	2
5	LOLO	M345		1,337	1,337	3
5	LYPK	BOBR		11,517	11,517	4
5	LYPK	HTSP		4,392	4,392	5
5	LYPK	LGBP		10,165	10,165	6
5	LYPK	M345		176,977	176,977	7
5	BOBR	ENPR		107,354	107,354	8
5	BOBR	HTSP		23,994	23,994	9
5	BOBR	M345		800	800	10
5	ENPR	BOBR		147,348	147,349	11
5	ENPR	M345		14,133	14,133	12
5	JBSN	BOBR		194,529	194,528	13
5	JBSN	M345		29,510	29,510	14
5	LGBP	BOBR		25	25	15
5	BOBR	LGBP		100	100	16
5	JEFF	LGBP		4,814	4,814	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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.
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF
2	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
3	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF
4	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF
5	Powerex Corp.	PacifiCorp East	Avista	NF
6	Powerex Corp.	PacifiCorp East	Sierra Pacific Power	NF
7	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
8	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
9	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF
10	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
12	Powerex Corp.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
13	Powerex Corp.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
14	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
15	Powerex Corp.	PacifiCorp West	NorthWestern/PacifiCorp East	NF
16	Powerex Corp.	PacifiCorp West	Bonneville Power Administration	NF
17	Powerex Corp.	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 (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BOBR	ENPR		829	829	1
5	BOBR	HTSP		4,256	4,256	2
5	BOBR	JBSN		120	120	3
5	BOBR	LGBP		50,394	50,394	4
5	BOBR	LOLO		306	306	5
5	BOBR	M345		3,624	3,624	6
5	ENPR	BOBR		26,435	26,435	7
5	ENPR	JBSN		48	48	8
5	ENPR	M345		12,446	12,446	9
5	HTSP	BOBR		175	175	10
5	HTSP	JBSN		239	239	11
5	HTSP	LGBP		3,391	3,391	12
5	HTSP	M345		2,657	2,657	13
5	JBSN	BOBR		1,435	1,435	14
5	JBSN	HTSP		52	52	15
5	JBSN	LGBP		81,829	81,829	16
5	JBSN	M345		19,070	19,070	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	Powerex Corp.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
3	Powerex Corp.	Bonneville Power Administratio	PacifiCorp East	NF
4	Powerex Corp.	Bonneville Power Administratio	PacifiCorp West	NF
5	Powerex Corp.	Bonneville Power Administratio	Sierra Pacific Power	NF
6	Powerex Corp.	Avista	PacifiCorp East	NF
7	Powerex Corp.	Avista	Sierra Pacific Power	NF
8	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF
9	Powerex Corp.	Sierra Pacific Power	PacifiCorp West	NF
10	Powerex Corp.	Sierra Pacific Power	Bonneville Power Administration	NF
11	Powerex Corp.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
12	PP & L Montana	PacifiCorp East	Bonneville Power Administration	NF
13	PP & L Montana	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	PP & L Montana	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
15	PP & L Montana	NorthWestern/PacifiCorp East	Avista	NF
16	PP & L Montana	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	PP & L Montana	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	JEFF	BOBR		84	84	1
5	JEFF	M345		5,054	5,054	2
5	LGBP	BOBR		33,825	33,825	3
5	LGBP	JBSN		1,463	1,463	4
5	LGBP	M345		11,615	11,615	5
5	LOLO	BOBR		1,740	1,740	6
5	LOLO	M345		4,494	4,494	7
5	M345	BOBR		156	156	8
5	M345	ENPR		53	53	9
5	M345	LGBP		14,478	14,478	10
5	MLCK	LGBP		50	50	11
5	BOBR	LGBP		5,303	5,303	12
5	HTSP	BOBR		135	135	13
5	HTSP	LGBP		2,245	2,245	14
5	HTSP	LOLO		552	552	15
5	JEFF	BOBR		131	131	16
5	JEFF	LGBP		1,400	1,400	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	PP & L Montana	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
2	PP & L Montana	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	PPM Energy	PacifiCorp East	PacifiCorp West	NF
4	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
5	PPM Energy	PacifiCorp East	Sierra Pacific Power	NF
6	PPM Energy	PacifiCorp West	PacifiCorp East	NF
7	PPM Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	PPM Energy	PacifiCorp West	PacifiCorp East	NF
9	PPM Energy	PacifiCorp West	Bonneville Power Administration	NF
10	PPM Energy	Bonneville Power	PacifiCorp East	NF
11	PPM Energy	Avista	PacifiCorp East	NF
12	Public Service of Colorado	PacifiCorp East	Bonneville Power Administration	NF
13	Public Service of Colorado	PacifiCorp West	PacifiCorp West	NF
14	Public Service of Colorado	Bonneville Power	PacifiCorp West	NF
15	Puget Sound Energy Marketing	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
16	Sempra Energy Trading Corp	PacifiCorp West	PacifiCorp East	NF
17	Sempra Energy Trading Corp	PacifiCorp West	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	JEFF	M345		15	15	1
5	M345	HTSP		50	50	2
5	BOBR	ENPR		183	183	3
5	BOBR	LGBP		18,645	18,645	4
5	BOBR	M345		25	25	5
5	ENPR	BOBR		97	97	6
5	HTSP	BOBR		175	175	7
5	JBSN	BOBR		125	125	8
5	JBSN	LGBP		360	360	9
5	LGBP	BOBR		2,060	2,060	10
5	LOLO	BOBR		2,825	2,825	11
5	BOBR	LGBP		200	200	12
5	ENPR	JBSN		3,113	3,113	13
5	LGBP	JBSN		171	171	14
5	HTSP	LGBP		935	935	15
5	ENPR	BOBR		22,725	22,725	16
5	ENPR	M345		423	423	17
			0	**4,597,529**	**4,594,762**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Sempra Energy Trading Corp	Avista	PacifiCorp East	NF
2	Sempra Energy Trading Corp	Avista	Sierra Pacific Power	NF
3	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
4	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
5	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
6	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
7	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
8	Sierra Pacific Power	Bonneville Power Administratio	Sierra Pacific Power	NF
9	Sierra Pacific Power	Avista	PacifiCorp East	NF
10	Sierra Pacific Power	Avista	Sierra Pacific Power	NF
11	Sierra Pacific Power	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
12	Sierra Pacific Power	Sierra Pacific Power	Bonneville Power Administration	NF
13	TransAlta Energy Marketing (US) Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	TransAlta Energy Marketing (US) Inc.	Avista	Sierra Pacific Power	NF
15				
16				
17				
	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	04/22/2005	End of 2004/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
5	LOLO	BOBR		8,991	8,991	1
5	LOLO	M345		2,685	2,685	2
5	BOBR	M345		197,428	197,428	3
5	ENPR	M345		70,538	70,538	4
5	HTSP	M345		48,553	48,553	5
5	JBSN	M345		48,580	48,580	6
5	JEFF	M345		230,432	230,432	7
5	LGBP	M345		515,926	515,926	8
5	LOLO	BOBR		1,568	1,568	9
5	LOLO	M345		289,364	289,364	10
5	M345	HTSP		819	819	11
5	M345	LGBP		2,319	2,319	12
5	HTSP	BOBR		64	64	13
5	LOLO	M345		105	105	14
0						15
						16
						17
			0	4,597,529	4,594,762	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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.
786,909	-279,511		507,398	1
1,256,532	-374,661		881,871	2
458,343	-42,880		415,463	3
1,421,320	-887,845		533,475	4
15,000			15,000	5
	11,221		11,221	6
		4,860	4,860	7
4,621	5,301		9,922	8
54,142		54,088	108,230	9
	436,242		436,242	10
	22,570		22,570	11
	536,729		536,729	12
	62,364		62,364	13
	45,344		45,344	14
	1,166,201		1,166,201	15
	72,238		72,238	16
	3,612		3,612	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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.
	965		965	1
	58,264		58,264	2
	221		221	3
	16,275		16,275	4
	539,865		539,865	5
	4,485		4,485	6
	50,839		50,839	7
	138		138	8
	12,976		12,976	9
	23,171		23,171	10
	254,551		254,551	11
	233,151		233,151	12
	30,448		30,448	13
	1,655		1,655	14
	222,299		222,299	15
	22,801		22,801	16
	6,609		6,609	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,207		2,207	1
	174		174	2
	3,769		3,769	3
	1,305		1,305	4
	304		304	5
	10,459		10,459	6
	1,208		1,208	7
	148		148	8
	93		93	9
	2,854		2,854	10
	691		691	11
	35,447		35,447	12
	1,094		1,094	13
	304,610		304,610	14
	1,642		1,642	15
	6,754		6,754	16
	10,268		10,268	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	7,107		7,107	1
	8,295		8,295	2
	4,813		4,813	3
	41,463		41,463	4
	15,812		15,812	5
	36,596		36,596	6
	637,149		637,149	7
	421,068		421,068	8
	94,110		94,110	9
	3,138		3,138	10
	577,938		577,938	11
	55,433		55,433	12
	762,986		762,986	13
	115,745		115,745	14
	98		98	15
	378		378	16
	18,177		18,177	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,310		4,310	1
	22,126		22,126	2
	624		624	3
	261,986		261,986	4
	1,591		1,591	5
	18,840		18,840	6
	137,429		137,429	7
	250		250	8
	64,704		64,704	9
	910		910	10
	1,243		1,243	11
	17,629		17,629	12
	13,813		13,813	13
	7,460		7,460	14
	270		270	15
	425,409		425,409	16
	99,140		99,140	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.
	437		437	1
	26,275		26,275	2
	175,848		175,848	3
	7,606		7,606	4
	60,384		60,384	5
	9,046		9,046	6
	23,363		23,363	7
	811		811	8
	275		275	9
	75,267		75,267	10
	260		260	11
	15,569		15,569	12
	396		396	13
	6,591		6,591	14
	1,621		1,621	15
	385		385	16
	4,110		4,110	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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.
	44		44	1
	147		147	2
	693		693	3
	70,574		70,574	4
	95		95	5
	367		367	6
	662		662	7
	473		473	8
	1,363		1,363	9
	7,797		7,797	10
	10,693		10,693	11
	863		863	12
	13,431		13,431	13
	738		738	14
	3,740		3,740	15
	267,668		267,668	16
	4,982		4,982	17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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.
	105,901		105,901	1
	31,625		31,625	2
	660,871		660,871	3
	236,119		236,119	4
	162,526		162,526	5
	162,617		162,617	6
	771,349		771,349	7
	1,727,012		1,727,012	8
	5,249		5,249	9
	968,618		968,618	10
	2,741		2,741	11
	7,763		7,763	12
	497		497	13
	816		816	14
				15
				16
				17
3,996,867	**12,152,983**	**58,948**	**16,208,798**	

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

The network service agreement between Idaho Power and the Bonnefille Power Administration for the Oregon Trail Electric Cooperative expires September 30,2011. The billing demand for the 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, 2004.
The billing demand for network service is the customer's demand at the time of Idaho Power 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 Oregon Trail Electric Cooperative expires September 30, 2011.
The billing demand for network service is the customer's demand at the time of Idaho Power transmission system peak and varies by month.

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

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

The agreement between Idaho Power and the Bonneville Power Administration expires September 30, 2016.

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

The contract between Idaho Power and the Milner Irrigation District will automatically renew on December 31, 2004 for a five year term unless either party provides prior notice.

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

The agreement between Idaho Power and the City of Seattle expires December 31, 2007.
Contract demand for 2004 was zero.

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

Monthly customer charge.

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on September 30, 2010.

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

This was a 2003 invoice that was not booked until 2004.

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

The contract between Idaho Power and PacifiCorp is for the life of Bridger project per 1992 Restated Transmission Service Agreement (RTSA) FERC filing 3/9/92.

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Delivered Power to Whlr							
2	Bonneville Power Admin	LFP	163,446	163,446	49,446			49,446
3	Clatskanie PUD	NF	1,040	1,040		1,980		1,980
4	Northwestern Energy	NF	1,594	1,594		7,428		7,428
5	Northwestern Energy	NF	100,930	100,930		547,400		547,400
6	Okanogan County	NF	160	160		320		320
7	Seattle City Light	NF	5,840	5,840		13,900		13,900
8	Sierra Pacific Power Co	NF	41,920	41,920		75,801		75,801
9	Snohomish County PUD	NF	5,120	5,120		10,368		10,368
10								
11	Received Power from Whl							
12	Avista Corp WWP Div	NF	160,323	160,323		1,008,122		1,008,122
13	Avista Corp WWP Div	SFP	574,602	574,602		2,070,798		2,070,798
14	Bonneville Power Admin	NF	25,514	25,514		130,906		130,906
15	Bonneville Power Admin	LFP	315,878	315,878	1,025,142			1,025,142
16	Clatskanie PUD	NF	2,344	2,344		4,630		4,630
	TOTAL		2,052,977	2,052,977	1,261,588	7,180,275		8,441,863

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Northwestern Energy LLC	SFP	15,624	15,624		71,400		71,400
2	Northwestern Energy LLC	LFP	103,567	103,567	187,000	13,464		200,464
3	Okanogan County PUD	NF	3,648	3,648		7,296		7,296
4	PacifiCorp Inc	NF	73,163	73,163		625,972		625,972
5	PacifiCorp Inc	SFP	311,229	311,229		2,323,834		2,323,834
6	PacifiCorp Inc	AD				-29,006		-29,006
7	Portland General Elect	NF	9,280	9,280		20,880		20,880
8	Seattle City Light	NF	9,412	9,412		23,803		23,803
9	Sierra Pacific Power Co	NF	17,102	17,102		30,280		30,280
10	Snohomish County PUD	NF	89,823	89,823		173,693		173,693
11	Tacoma Power	NF	21,418	21,418		47,006		47,006
12								
13								
14								
15								
16								
	TOTAL		2,052,977	2,052,977	1,261,588	7,180,275		8,441,863

Schedule Page: 332 Line No.: 2 Column: a

(1) Bonneville Power Administration LFP 9/30/2016

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

(2) Bonneville Power Administration LFP 7/25/2011

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

(3)Norhtwestern Energy, L.L.C. LFP Contract can be terminated at anytime, with 30 days prior notice

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

(4)(a) Adjustment of ($28,838.10) to Pacificorp Inc in May 2003. Pacificorp did not remove amount from invoice creating overpayment.

(4)(b) Adjustment of ($167.68) for Pacificorp losses in December 2003.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	22,592
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,377,375
6	Rotheford Barker	19,963
7	Jack Lemley	20,596
8	Gary Michael	21,772
9	John Miller	39,000
10	Peter O'Neill	19,560
11	Richard Reiten	16,695
12	Thomas Wilford	13,515
13	Robert Tintsman	21,270
14	Christopher Culp	19,020
15	Joan Smith	9,619
16		
17	Chambers of Commerce & Other Civic Organizations	74,879
18		
19	Memberships :	
20	Associated Taxpayers of Idaho	15,939
21	Association of Idaho Cities	560
22	Baker County Unlimited	500
23	Idaho Association of Counties	800
24	Idaho Water Users Association	1,200
25	National Hydropower Assoc	20,173
26	Northwest Hydroelectric	300
27	Pacific NW Utilities	36,686
28	Utility Economic Development	495
29	Utility Wind Interest Group	5,000
30	West Associates	28,374
31	Western Energy Institute	40,000
32	Wyoming Taxpayers Association	5,125
33		
34	Miscellaneous General Management:	
35	New York Stock Exchange	38,157
36	Pacific Exchange	850
37	Standard & Poor's	89,500
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,959,515

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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			10,050,419		10,050,419
2	Steam Production Plant	22,416,607				22,416,607
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,506,866		312		12,507,178
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	1,481,062				1,481,062
7	Transmission Plant	11,795,378				11,795,378
8	Distribution Plant	25,115,076				25,115,076
9	General Plant	17,671,901				17,671,901
10	Common Plant-Electric					
11	TOTAL	90,986,890		10,050,731		101,037,621

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2004 Amortization	Balance to be amortized 12/31/03	Remaining months of amortization 12/31/04
(1)	24,364	15,372	8,992	-
(2)	48,000	12,000	36,000	36
(3)	7,341,155	297,576	8,443,567	-
(4)	25,298,196	9,713,531	20,179,079	-
(5)	259,334	12,252	247,082	242
Total	32,971,049	10,050,731	28,914,721	

(1) T E Roach development archaeological study, FERC & Oregon license costs (temination date July 31, 2005).
(2) Shoshone-Bannock Tribe license and use agreement (termination date December 31, 2023).
(3) Middle snake relicensing costs (amortized over a 30-year liscense period).
(4) Computer software packages (amortized over a 60 month period from date of purchase).
(5) American Falls dam road rebuild (termination date February 28, 2025).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	310.00	203	75.00		2.27	R4.0	19.20
13	311.00	130,003	90.00	-10.00	2.59	S1.0	18.30
14	312.10	78,929	55.00	-10.00	2.76	R3.0	19.10
15	312.20	393,642	70.00	-10.00	2.92	R1.5	18.10
16	312.30	3,917	25.00	20.00	2.76	R3.0	16.40
17	314.00	116,615	50.00	-10.00	3.48	S0.5	17.20
18	315.00	61,107	65.00		2.16	S1.5	17.80
19	316.00	11,214	45.00		3.14	R0.5	16.40
20	316.40	232	9.00	25.00	1.55	L3.0	5.40
21	316.50	33	9.00	25.00	3.57	L3.0	3.50
22	316.70	22	17.00	25.00	3.45	S2.5	8.10
23	316.80	1,192	14.00	35.00	4.31	L0.5	9.40
24	317.000	2,775					
25	Subtotal Steam	799,884					
26	331.00	129,091	100.00	-20.00	2.37	S1.0	36.80
27	332.10	19,460	85.00	-10.00	1.93	S4.0	31.40
28	332.20	218,345	85.00	-10.00	1.95	S4.0	34.10
29	332.30	5,600	39.00		1.44	SQUARE	63.60
30	333.00	185,352	80.00	-5.00	1.83	R3.0	38.00
31	334.00	36,164	47.00		2.85	R1.5	28.00
32	335.00	14,146	100.00		1.84	S0.0	34.90
33	336.00	6,950	75.00		1.95	R3.0	34.70
34	Subtotal Hydro	615,108					
35	341.00	1,207	35.00		2.84	SQUARE	34.50
36	342.00	1,677	35.00		2.83	SQUARE	33.90
37	343.00	766	35.00		2.88	SQUARE	34.50
38	344.00	43,894	35.00		2.84	SQUARE	34.50
39	345.00	2,177	35.00		2.79	SQUARE	34.50
40	346.00	2,570	35.00		2.88	SQUARE	34.50
41	Subtotal Other	52,291					
42	350.00	20,981	65.00		1.54	R3.0	52.30
43	352.00	31,307	60.00	-20.00	1.29	R3.0	48.00
44	353.00	228,309	45.00	-5.00	2.12	S0.5	32.70
45	354.00	76,573	60.00	-30.00	2.45	S4.0	37.30
46	355.00	89,925	55.00	-60.00	2.94	R2.0	39.90
47	356.00	111,461	60.00	-20.00	1.96	R2.0	41.40
48	359.00	319	65.00		1.07	R3.0	27.00
49	Subtotal Transmission	558,875					
50	361.00	18,722	55.00	-20.00	2.05	R2.5	40.70

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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	362.00	129,850	50.00		1.64	O1.0	43.60
13	364.00	185,763	41.00	-50.00	3.67	R1.5	29.80
14	365.00	94,136	46.00	-30.00	3.25	R2.0	29.50
15	366.00	39,214	60.00	-25.00	2.04	R2.0	51.90
16	367.00	147,816	37.00	-10.00	2.73	S1.5	28.60
17	368.00	272,982	35.00	5.00	1.73	R2.0	27.10
18	369.00	46,412	30.00	-30.00	3.69	S2.0	20.50
19	370.00	47,457	30.00		4.06	L2.0	19.70
20	371.10	359	8.00		28.42	S5.0	2.30
21	371.20	2,124	11.00	-20.00	11.85	R0.5	7.00
22	373.00	3,969	20.00	-20.00	5.75	R1.0	10.90
23	Subtotal Distribution	988,804					
24	390.11	25,377	100.00	-5.00	2.27	S1.5	38.50
25	390.12	27,743	50.00	-5.00	2.17	R3.0	36.00
26	390.20	7,086	25.00		3.85	S3.0	16.90
27	391.10	10,812	20.00		9.66	SQUARE	7.70
28	391.20	16,599	5.00		20.00	SQUARE	5.00
29	391.201	18,005	5.00		34.48	SQUARE	1.70
30	391.21	2,553	6.00		16.67	S5.0	6.00
31	391.211	4,039	6.00		31.98	S5.0	2.00
32	392.10	293	9.00	25.00	1.78	L3.0	7.90
33	392.30	1,989	15.00	50.00	3.79	S2.0	15.00
34	392.40	14,789	9.00	25.00	3.45	L3.0	6.90
35	392.50	422	9.00	25.00	8.45	L3.0	
36	392.60	19,821	17.00	25.00	4.72	S2.5	10.20
37	392.70	3,487	17.00	25.00	4.26	S2.5	7.90
38	392.90	3,029	30.00	25.00	1.93	S1.0	21.90
39	393.00	1,007	25.00		7.89	SQUARE	8.70
40	394.00	3,833	20.00		8.31	SQUARE	8.10
41	395.00	9,230	20.00		6.53	SQUARE	9.80
42	396.00	6,325	14.00	35.00	6.90	L0.5	7.70
43	397.10	8,693	15.00		11.61	SQUARE	5.70
44	397.20	13,155	15.00		9.99	SQUARE	7.40
45	397.30	2,980	15.00		9.99	SQUARE	6.70
46	397.40	1,273	10.00		16.45	SQUARE	5.20
47	398.00	2,345	15.00		8.50	SQUARE	8.80
48	Subtotal General	204,885					
49	Total Plant	3,219,847					
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 administrative charges	3,417,660		3,417,660	
3					
4	General Regulatory Expenses:				
5	Other Expenses		313,229	313,229	
6					
7	Regulatory Commission Expenses - Idaho				
8	Intervenor Funding (various cases)		40,000	40,000	
9	Lost Revenue Appeal IPC-E-01-34		550	550	
10	General Rate Case IPC-E-03		15,400	15,400	
11	Other Expenses		19,458	19,458	
12					
13	Oregon Hydro - Fees Amortization	158,506		158,506	
14					
15	Regulatory Commission Expenses - Oregon				
16	Other Expenses		12,127	12,127	
17					
18					
19					
20					
21					
22					
23					
24					
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29					
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31					
32					
33					
34					
35					
36					
37					
38					
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40					
41					
42					
43					
44					
45					
46	TOTAL	3,576,166	400,764	3,976,930	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
electric	928	3,417,660					2
							3
							4
electric	928	313,229					5
							6
							7
electric	928	40,000					8
electric	928	550					9
electric	928	15,400					10
electric	928	19,458					11
							12
electric	928	158,506					13
							14
							15
electric	928	12,129					16
							17
							18
							19
							20
							21
							22
							23
							24
							25
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							27
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							37
							38
							39
							40
							41
							42
							43
							44
							45
		3,976,932					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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
(3) Transmission
a. Overhead
b. Underground
(4) Distribution
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $5,000.)
(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	A. Electric R, D & D Performed internally:	
2	(1) Generation	
3	e. unconventional generation	Air Conditiioning Cycling Pilot
4		Irrigation Peak Clipping
5		Energy STAR Homes Northwest
6		Commercial Efficiency Program
7		Air Care+Pilot
8		Industrial Efficiency Program
9		Irrigation Efficiency Program
10		School Building Operator training
11		Small project/Education Funds
12		EEAG
13		DSM Analysis
14		Other DSM Costs
15		
16		
17	(7) Costs Incurred	
18	B. 4 Research Support to Others	BPA Conservation & Renewable discount
19		Northwest Energy Efficiency Alliance
20		Low Income Weatherization Assistance
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Total R, D & D	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 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 $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
273,973			273,973		3
319,424			319,424		4
129,825			129,825		5
28,821			28,821		6
72			72		7
187,473			187,473		8
73,188			73,188		9
43,969			43,969		10
23,449			23,449		11
3,448			3,448		12
138,249			138,249		13
300,000			300,000		14
					15
					16
					17
	1,000,000		1,000,000		18
	1,200,000		1,200,000		19
	500,000		500,000		20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
1,521,891	2,700,000		4,221,891		38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	10,277,882		
4	Transmission	5,430,894		
5	Distribution	14,410,861		
6	Customer Accounts	9,714,335		
7	Customer Service and Informational	3,651,373		
8	Sales			
9	Administrative and General	29,752,683		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	73,238,028		
11	Maintenance			
12	Production	5,874,850		
13	Transmission	2,896,235		
14	Distribution	6,740,915		
15	Administrative and General	739,889		
16	TOTAL Maint. (Total of lines 12 thru 15)	16,251,889		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	16,152,732		
19	Transmission (Enter Total of lines 4 and 13)	8,327,129		
20	Distribution (Enter Total of lines 5 and 14)	21,151,776		
21	Customer Accounts (Transcribe from line 6)	9,714,335		
22	Customer Service and Informational (Transcribe from line 7)	3,651,373		
23	Sales (Transcribe from line 8)			
24	Administrative and General (Enter Total of lines 9 and 15)	30,492,572		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	89,489,917	3,416,157	92,906,074
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Enter Total of lines 28 thru 37)			
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	89,489,917	3,416,157	92,906,074
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	34,579,868		34,579,868
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	34,579,868		34,579,868
69	Plant Removal (By Utility Departments)			
70	Electric Plant			
71	Gas Plant			
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)			
74	Other Accounts (Specify, provide details in footnote):			
75	Misc Deferred & Regulatory assets	1,151,861		1,151,861
76	Paid Absences	15,037,256		15,037,256
77	Other Accounts	4,399,737		4,399,737
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	20,588,854		20,588,854
96	TOTAL SALARIES AND WAGES	144,658,639	3,416,157	148,074,796

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January	2,601	5	19	2,196	174	79	2	150	
2	February	2,433	13	8	2,072	180	79	2	100	
3	March	2,474	3	8	1,877	150	305	2	140	
4	Total for Quarter	7,508			6,145	504	463	6	390	
5	April	2,648	30	23	1,661	185	347	2	420	
6	May	2,981	4	19	2,083	226	1,107	2	290	
7	June	3,520	24	17	2,843	137	347	3	190	
8	Total for Quarter	9,149			6,587	548	1,801	7	900	
9	July	3,563	14	18	2,825	290	301	1	100	
10	August	3,307	2	18	2,769	134	301	3	100	
11	September	3,015	1	16	2,364	223	949	2	125	
12	Total for Quarter	9,885			7,958	647	1,551	6	325	
13	October	2,450	25	8	1,735	149	376		190	
14	November	2,744	30	8	2,061	172	376	3	132	
15	December	2,603	20	19	2,033	166	376	3	25	
16	Total for Quarter	7,797			5,829	487	1,128	6	347	
17	Total for Year to	34,339			26,519	2,186	4,943	25	1,962	

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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	04/22/2005	End of 2004/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,239,589
3	Steam	7,281,432			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	104,331
5	Hydro-Conventional	6,040,502			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,781,019
7	Other	21,934			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,343,868	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	4,259,876	27	Total Energy Losses	1,336,236
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,461,175
12	Received	205,930			
13	Delivered	351,266			
14	Net Exchanges (Line 12 minus line 13)	-145,336			
15	Transmission For Other (Wheeling)				
16	Received	4,597,529			
17	Delivered	4,594,762			
18	Net Transmission for Other (Line 16 minus line 17)	2,767			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,461,175			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: IDAHO POWER COMPANY - SYSTEM LOAD

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,334,017	72,251	2,196	5	7PM
30	February	1,258,704	140,373	2,072	13	8AM
31	March	1,455,063	431,459	1,877	3	8AM
32	April	1,370,496	335,462	1,758	16	9AM
33	May	1,493,443	302,534	2,109	4	7PM
34	June	1,750,724	315,058	2,843	24	5PM
35	July	1,780,638	191,534	2,825	14	6PM
36	August	1,683,160	221,018	2,792	22	6PM
37	September	1,525,329	353,612	2,395	1	5PM
38	October	1,173,703	99,934	1,735	25	8AM
39	November	1,202,388	106,834	2,063	30	8AM
40	December	1,433,510	210,950	2,033	20	7PM
41	TOTAL	17,461,175	2,781,019			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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			56.05		
6	Net Peak Demand on Plant - MW (60 minutes)	701			60		
7	Plant Hours Connected to Load	8784			6448		
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	4924715000			353543000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	62837544			13575473		
15	Equipment Costs	363944819			51815464		
16	Asset Retirement Costs	0			0		
17	Total Cost	427276166			65497547		
18	Cost per KW of Installed Capacity (line 17/5) Including	554.5440			1168.5557		
19	Production Expenses: Oper, Supv, & Engr	104062			821222		
20	Fuel	62790590			4409531		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2749435			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	4565813			145173		
27	Rents	268376			431771		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1477			2670682		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	8174881			0		
32	Maintenance of Electric Plant	4257391			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2880164			26742		
34	Total Production Expenses	85792189			8505121		
35	Expenses per Net KWh	0.0174			0.0241		
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	2803820	17886	0	207426	1196	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9306	140000	0	8405	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	21.129	54.548	0.000	19.261	55.509	0.000
41	Average Cost of Fuel per Unit Burned	22.012	53.435	0.000	20.920	46.053	0.000
42	Average Cost of Fuel Burned per Million BTU	1.183	9.088	0.000	1.245	7.898	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.013	0.000	0.000	0.012	0.000	0.000
44	Average BTU per KWh Net Generation	10618.000	0.000	0.000	9882.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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: (f)	Line No.
Steam	Gas Turbine		1
Outdoor	Conventional		2
1981	2001		3
1985	2001		4
283.50	90.00	0.00	5
268	89	0	6
8676	398	0	7
0	100000	0	8
0	0	0	9
0	0	0	10
0	5	0	11
2003174000	21798000	0	12
681106	219037	0	13
53590120	1195464	0	14
251142150	50128220	0	15
0	0	0	16
305413376	51542721	0	17
1077.2959	572.6969	0.0000	18
261852	112088	0	19
31187249	4861198	0	20
0	0	0	21
2583991	0	0	22
0	0	0	23
0	0	0	24
1558514	135246	0	25
1157530	131621	0	26
10566	0	0	27
0	0	0	28
187711	0	0	29
358798	90459	0	30
4490351	39808	0	31
924812	164266	0	32
169235	0	0	33
42890609	5534686	0	34
0.0214	0.2539	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
COAL	OIL		GAS						36
TONS	BARRELS		MCF						37
969246	5933	0	47779	0	0	0	0	0	38
10267	138778	0	1038	0	0	0	0	0	39
30.538	63.218	0.000	15.067	0.000	0.000	0.000	0.000	0.000	40
31.792	57.627	0.000	15.067	0.000	0.000	0.000	0.000	0.000	41
1.548	9.887	0.000	14.510	0.000	0.000	0.000	0.000	0.000	42
0.016	0.000	0.000	0.101	0.000	0.000	0.000	0.000	0.000	43
9953.000	0.000	0.000	6944.000	0.000	0.000	0.000	0.000	0.000	44

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949
4	Year Last Unit was Installed	1978	1950
5	Total installed cap (Gen name plate Rating in MW)	92.30	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	75	60
7	Plant Hours Connect to Load	4,743	8,783
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	112	80
10	(b) Under the Most Adverse Oper Conditions	0	74
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	199,617,000	281,658,000
13	Cost of Plant		
14	Land and Land Rights	875,615	463,556
15	Structures and Improvements	11,812,406	664,675
16	Reservoirs, Dams, and Waterways	4,242,904	7,428,168
17	Equipment Costs	30,886,109	6,536,751
18	Roads, Railroads, and Bridges	306,333	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	48,123,367	15,579,627
21	Cost per KW of Installed Capacity (line 20 / 5)	521.3799	207.7284
22	Production Expenses		
23	Operation Supervision and Engineering	158,940	356,447
24	Water for Power	853,891	218,122
25	Hydraulic Expenses	101,824	202,245
26	Electric Expenses	40,445	19,225
27	Misc Hydraulic Power Generation Expenses	163,236	87,762
28	Rents	137	2,784
29	Maintenance Supervision and Engineering	125,350	67,158
30	Maintenance of Structures	115,888	66,180
31	Maintenance of Reservoirs, Dams, and Waterways	139	155,345
32	Maintenance of Electric Plant	216,826	250,067
33	Maintenance of Misc Hydraulic Plant	122,032	131,434
34	Total Production Expenses (total 23 thru 33)	1,898,708	1,556,769
35	Expenses per net KWh	0.0095	0.0055

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
652	14	221	6
8,784	8,784	8,784	7
			8
728	14	220	9
220	1	202	10
6	2	6	11
1,881,325,000	35,715,000	825,345,000	12
			13
5,654,942	82,142	866,938	14
30,023,963	7,364,154	9,835,132	15
66,742,791	3,145,630	30,375,714	16
51,284,102	12,376,598	14,782,645	17
518,444	122,668	565,842	18
0	0	0	19
154,224,242	23,091,192	56,426,271	20
263.4510	1,859.1942	296.9804	21
			22
479,095	152,303	322,180	23
188,501	91,046	116,813	24
359,462	150,916	239,650	25
286,600	66,038	271,044	26
480,191	238,127	339,334	27
209,671	100	36,004	28
158,354	43,012	158,037	29
174,315	27,706	159,819	30
148,368	444	90,684	31
360,693	52,862	254,516	32
420,459	134,505	334,645	33
3,265,709	957,059	2,322,726	34
0.0017	0.0268	0.0028	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	432	2,160
7	Plant Hours Connect to Load	8,784	8,779
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	450	24
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	6	2
12	Net Generation, Exclusive of Plant Use - Kwh	1,623,901,000	154,935,000
13	Cost of Plant		
14	Land and Land Rights	1,563,504	205,375
15	Structures and Improvements	2,402,435	2,143,622
16	Reservoirs, Dams, and Waterways	52,511,953	3,371,066
17	Equipment Costs	14,999,231	2,948,654
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	72,296,315	8,973,400
21	Cost per KW of Installed Capacity (line 20 / 5)	184.6649	412.1911
22	Production Expenses		
23	Operation Supervision and Engineering	185,519	71,368
24	Water for Power	78,624	459,280
25	Hydraulic Expenses	143,330	44,822
26	Electric Expenses	67,264	61,502
27	Misc Hydraulic Power Generation Expenses	245,179	44,546
28	Rents	60,150	0
29	Maintenance Supervision and Engineering	149,323	43,304
30	Maintenance of Structures	40,251	1,736
31	Maintenance of Reservoirs, Dams, and Waterways	224,556	36,420
32	Maintenance of Electric Plant	203,526	172,398
33	Maintenance of Misc Hydraulic Plant	576,093	66,236
34	Total Production Expenses (total 23 thru 33)	1,973,815	1,001,612
35	Expenses per net KWh	0.0012	0.0065

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
84	20	17	6
8,780	8,784	5,471	7
			8
89	26	54	9
84	14	50	10
5	4	4	11
355,512,000	113,034,000	33,363,000	12
			13
2,052,202	51,675	255,499	14
2,700,432	25,151,154	10,808,047	15
9,742,555	13,641,459	7,908,304	16
7,022,775	30,351,406	20,434,828	17
238,871	835,946	1,917,603	18
0	0	0	19
21,756,835	70,031,640	41,324,281	20
262.7637	2,801.2656	783.5472	21
			22
725,094	204,746	231,814	23
267,364	71,526	68,312	24
877,434	169,172	123,005	25
37,635	21,646	34,630	26
203,500	104,923	111,180	27
60,400	7,117	996	28
67,031	41,245	32,001	29
59,790	69,748	37,654	30
143,294	19,765	28,273	31
146,578	128,449	131,135	32
200,071	121,549	112,144	33
2,788,191	959,886	911,144	34
0.0078	0.0085	0.0273	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	31	13
7	Plant Hours Connect to Load	8,783	8,724
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	13
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	2
12	Net Generation, Exclusive of Plant Use - Kwh	182,226,000	81,083,000
13	Cost of Plant		
14	Land and Land Rights	172,970	311,407
15	Structures and Improvements	1,442,507	1,138,033
16	Reservoirs, Dams, and Waterways	3,936,469	512,401
17	Equipment Costs	4,598,895	2,068,295
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,180,200	4,081,519
21	Cost per KW of Installed Capacity (line 20 / 5)	295.0783	326.5215
22	Production Expenses		
23	Operation Supervision and Engineering	342,582	88,176
24	Water for Power	73,172	33,954
25	Hydraulic Expenses	229,964	62,383
26	Electric Expenses	16,298	15,951
27	Misc Hydraulic Power Generation Expenses	122,726	66,526
28	Rents	0	25
29	Maintenance Supervision and Engineering	45,051	24,375
30	Maintenance of Structures	55,813	23,843
31	Maintenance of Reservoirs, Dams, and Waterways	54,841	4,301
32	Maintenance of Electric Plant	133,869	88,002
33	Maintenance of Misc Hydraulic Plant	147,367	55,186
34	Total Production Expenses (total 23 thru 33)	1,221,683	462,722
35	Expenses per net KWh	0.0067	0.0057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	59	46	6
0	8,783	5,697	7
			8
0	70	59	9
0	63	1	10
0	7	2	11
0	185,011,000	19,423,000	12
			13
80,646	403,335	138,100	14
11,894,976	860,907	10,327,358	15
13,556,785	6,473,870	17,147,049	16
1,014,463	6,419,204	27,529,862	17
99,051	88,693	501,877	18
0	0	0	19
26,645,921	14,246,009	55,644,246	20
0.0000	237.4335	935.9840	21
			22
-473	989,489	109,916	23
0	147,847	1,346,950	24
3,606,918	352,157	72,247	25
0	153,741	41,224	26
0	151,632	149,474	27
0	1,157	1,379	28
0	58,234	32,336	29
0	116,270	38,489	30
0	85,689	8,986	31
0	186,673	56,744	32
0	127,898	37,522	33
3,606,445	2,370,787	1,895,267	34
0.0000	0.0128	0.0976	35

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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

American Falls generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

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

Cascade generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

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

Upstream storage in Brownlee Reservoir.

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	2.5	15,799	1,718,350
3	Thousand Springs	1912	8.80	6.2	52,555	4,691,209
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.0	136	901,055
8						
9						
10						
11						
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17	(1) Salmon units are classified as standby.					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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
687,340	13,927		64,476			2
533,092	180,969		91,368			3
						4
						5
						6
180,211				Diesel		7
						8
						9
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	85.16		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	225.86		1
5	State Line	Midpoint	345.00	345.00	S Tower	76.16		2
6	Kinport	Borah	345.00	345.00	S Tower	27.31		1
7	Midpoint	Borah #1	345.00	345.00	H Wood	79.37		1
8	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
9	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
10								
11	Quartz	LaGrande	230.00	230.00	H Wood	46.23		1
12	Midpoint	Hunt	230.00	230.00	S Tower	0.63		2
13	Brady	Antelope	230.00	230.00	H Wood	56.44		1
14	Brady	Treasureton	230.00	230.00	H Wood	0.13		1
15	Brady #1 & #2	Kinport	230.00	230.00	S Tower	18.02		2
16	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
17	Brownlee	Ontario	230.00	230.00	S Tower	74.86		1
18	Mora	Bowmont	138.00	230.00	S P Wood	9.86		1
19	Mora	Bowmont	138.00	230.00	H Wood	10.85		1
20	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.78		1
21	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
22	Boise Bench	Caldwell	230.00	230.00	S Tower	4.46		1
23	Boise Bench	Caldwell	230.00	230.00	H Wood	33.53		1
24	Boise Bench	Cloverdale	230.00	230.00	S Tower	16.05		2
25	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
26	Brownlee 714	Oxbow	230.00	230.00	SP Steel	10.80		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.34		1
28	Caldwell	Ontario	230.00	230.00	S Tower	3.31		1
29	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
30	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.11		1
31	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
32	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.65		1
33	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.99		2
34	Oxbow	Brownlee	230.00	230.00	S Tower	10.20		2
35	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
36					TOTAL	4,703.62	11.02	152

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,722,638	16,205,947					4
795 ACSR	571,979	10,996,449	11,568,428					5
1272 ACSR	344,220	6,028,033	6,372,253					6
715.5 ACSR	283,143	5,422,574	5,705,717					7
715.5 ACSR	64,851	5,983,183	6,048,034					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,175,013	2,226,427					11
715.5 ACSR	9,145	395,951	405,096					12
1272 ACSR	108,301	2,328,646	2,436,947					13
795 ACSR		6,186	6,186					14
715.5 ACSR	18,829	969,476	988,305					15
1272 ACSR	1,190	51,525	52,715					16
2X954 ACSR	1,676,838	20,246,910	21,923,748					17
715.5 ACSR	347,962	2,012,372	2,360,334					18
715.5 ACSR								19
1272 ACSR	1,899	212,523	214,422					20
1590 ACSR	2,138,236		2,138,236					21
1272 ACSR	817,054	2,761,586	3,578,640					22
715.5 ACSR								23
1272 ACSR	2,999,026	6,532,790	9,531,816					24
795 AAC		80,895	80,895					25
954 ACSR		16,463,438	16,463,438					26
2X954 ACSR	194,763	6,593,156	6,787,919					27
1272 ACSR								28
715.5 ACSR	336,186	3,404,693	3,740,879					29
715.5 ACSR								30
795 ACSR	42,995	1,782,886	1,825,881					31
795 ACSR								32
VARIOUS	261,229	7,994,996	8,256,225					33
1272 ACSR	6,033	1,191,291	1,197,324					34
715.5 ACSR	820,646	4,682,329	5,502,975					35
	20,341,978	269,491,947	289,833,925	5,502,879	3,017,527	2,176,624	10,697,030	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	04/22/2005	End of 2004/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	Boise Bench	Midpoint #2	230.00	230.00	H Wood	101.48		1
2	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.15		2
3	Pallette Jct	Imnaha	230.00	230.00	H Wood	23.85		2
4	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.16		2
5	Brownlee	Boise Bench	230.00	230.00	S Tower	102.23		2
6	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.36		1
7	Palette Jct	Enterprise	230.00	230.00	H Wood	28.83		1
8	Borah	Brady #2	230.00	230.00	S Tower	0.43		1
9	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
10	Borah	Brady #1	230.00	230.00	H Wood	3.97		1
11								
12	Goshen	State Line	161.00	161.00	H Wood	90.50		1
13	Don	Goshen	161.00	161.00	S Tower	2.39		2
14	Don	Goshen	161.00	161.00	H Wood	46.19		2
15								
16	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	84.40		2
17	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	2.58		2
18	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.11		2
19	Nampa	Caldwell	138.00	138.00	S P Wood	10.78		2
20	Upper Salmon	Mountain Home Jct		138.00	H Wood	4.31		1
21	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	49.32		1
22	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
23	Eastgate	Russet	138.00	138.00	S P Wood	2.07		1
24	Brady	Fremont	138.00	138.00	S Tower	1.00		2
25	Brady	Fremont	138.00	138.00	H Wood	24.32		2
26	Brady	Fremont	138.00	138.00	S P Wood	24.44		2
27	King	Lower Malad	138.00	138.00	H Wood	84.91		2
28	Emmett Jct	Payette	138.00	138.00	H Wood	60.54		2
29	Mountain Home AFB Tap		138.00	138.00	H Wood	6.21		1
30	Ontario	Quartz	138.00	138.00	H Wood	73.41		1
31	King	American Falls PP	138.00	138.00	S Tower	1.02		2
32	King	American Falls PP	138.00	138.00	H Wood	141.72		1
33	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
34								
35								
36					TOTAL	4,703.62	11.02	152

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
VARIOUS								1
1272 ACSR	23,308	2,032,869	2,056,177					2
1272 ACSR	138,477	1,208,587	1,347,064					3
1272 ACSR	10,737	1,253,156	1,263,893					4
954 ACSR	170,694	5,555,559	5,726,253					5
715.5 ACSR	246,660	4,589,451	4,836,111					6
1272 ACSR	51,122	1,633,094	1,684,216					7
1272 ACSR	3,068	200,632	203,700					8
715.5 ACSR								9
1272 ACSR	10,064	180,008	190,072					10
								11
250 COPPER	16,155	648,382	664,537					12
715.5 ACSR	76,041	1,623,921	1,699,962					13
397.5 ACSR								14
								15
250 COPPER	26,507	2,346,862	2,373,369					16
250 COPPER								17
715.5 ACSR	15,088	249,232	264,320					18
795 AAC	157,432	1,489,068	1,646,500					19
795 ACSR	47,687	1,696,746	1,744,433					20
VARIOUS								21
795 ACSR	43,568	764,183	807,751					22
795 AAC	270,823	557,504	828,327					23
VARIOUS	564,932	3,447,402	4,012,334					24
VARIOUS								25
VARIOUS								26
VARIOUS	76,823	1,378,401	1,455,224					27
VARIOUS	30,918	1,318,876	1,349,794					28
397.5 ACSR	1,955		1,955					29
VARIOUS	34,428	1,486,208	1,520,636					30
715.5 ACSR	134,494	3,943,879	4,078,373					31
715.5 ACSR								32
715.5 ACSR								33
								34
								35
	20,341,978	269,491,947	289,833,925	5,502,879	3,017,527	2,176,624	10,697,030	36

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
2	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
3	Upper Salmon A-B	King	138.00	138.00	H Wood	5.88		1
4	Upper Salmon B	Wells	138.00	138.00	H Wood	125.61		1
5	King	Wood River	138.00	138.00	H Wood	73.57		1
6	Boise Bench	Grove	138.00	138.00	S P Wood	10.63		2
7	Quartz	John Day	138.00	138.00	H Wood	67.32		1
8	Sinker Creek Tap		138.00	138.00	H Wood	2.83		1
9	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
10	Mora	Cloverdale	138.00	138.00	S P Wood	22.47		1
11	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
12	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
13	Wood River	Midpoint	138.00	138.00	H Wood	52.71		2
14	Wood River	Midpoint	138.00	138.00	S P Wood	16.74		2
15	Oxbow	McCall	138.00	138.00	H Wood	38.49		1
16	Oxbow	McCall	138.00	138.00	S P Wood	1.70		1
17	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.52		2
18	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
19	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.47		1
20	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.43		2
21	Pingree	Haven	138.00	138.00	S P Wood	11.77		1
22	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.28		2
23	Twin Falls	Russett	138.00	138.00	S P Wood	1.73		1
24	Blackfoot	Aiken	138.00	138.00	S P Wood	6.18		2
25	Peterson	Tendoy	138.00	138.00	H Wood	57.27		1
26	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.32		1
27	Boise Bench	Mora	138.00	138.00	H Wood	11.22		2
28	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
29	Gary Lane	Eagle	138.00	138.00	S P Wood	6.48		1
30	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	3.98	2.98	1
31	Boise Bench	Butler	138.00	138.00	S P Wood	0.08	4.02	1
32	Eagle	Star		138.00	S P Wood			
33	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.18	4.02	1
34	Butler	Wye	138.00	138.00	S P Steel	3.00		1
35	Valivue Tap		138.00	138.00	S P Steel	0.82		2
36					TOTAL	4,703.62	11.02	152

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
4\0	4,191	309,827	314,018					1
954 ACSR		13,539	13,539					2
250 COPPER	2,741	93,073	95,814					3
VARIOUS	28,490	1,745,804	1,774,294					4
VARIOUS	173,683	2,364,244	2,537,927					5
VARIOUS	225,602	1,629,593	1,855,195					6
397.5 ACSR	92,173	2,362,416	2,454,589					7
VARIOUS	20	77,199	77,219					8
715.5 ACSR	1,448,717	4,648,182	6,096,899					9
VARIOUS								10
1272 ACSR								11
250 COPPER	450	63,439	63,889					12
397.5 ACSR	281,064	6,374,306	6,655,370					13
397.5 ACSR								14
397.5 ACSR	84,183	1,752,478	1,836,661					15
397.5 ACSR								16
715.5 ACSR	211,131	1,452,119	1,663,250					17
715.5 ACSR	3,324	1,079,781	1,083,105					18
397.5 ACSR	14,927	587,404	602,331					19
715.5 ACSR	13,734	991,714	1,005,448					20
397.5 ACSR	11,213	778,092	789,305					21
VARIOUS	54,848	2,959,215	3,014,063					22
715.5 ACSR	16,790	206,158	222,948					23
715.5 ACSR	13,616	456,919	470,535					24
397.5 ACSR	395,696	3,449,949	3,845,645					25
715.5 ACSR	45,989	1,054,909	1,100,898					26
715.5 ACSR	14,697	632,718	647,415					27
795 AAC		49,642	49,642					28
795 AAC	489,037	2,139,599	2,628,636					29
1272 ACSR	935,725	2,811,708	3,747,433					30
1272 ACSR	34,687	551,319	586,006					31
715.5 ACSR		1,087,968	1,087,968					32
1272 ACSR	140,412	709,148	849,560					33
795 ACSR	471,769	1,059,039	1,530,808					34
795 ACSR		351,497	351,497					35
	20,341,978	269,491,947	289,833,925	5,502,879	3,017,527	2,176,624	10,697,030	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	04/22/2005	End of 2004/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
2	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
3	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
4	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
5	C J Strike	Strike Jct	138.00	138.00	S Tower	4.31		2
6	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.55		1
7								
8	Strike Jct	Bowmont		138.00	H Wood	0.05		1
9	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
10	Strike Jct	Bowmont	138.00	138.00	H Wood	68.14		1
11	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.43		2
12	Bliss	King	138.00	138.00	H Wood	10.44		1
13	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
14	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
15								
16								
17								
18	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
19								
20								
21	69 Kv Lines		69.00	69.00	H Wood	166.31		1
22	69 Kv Lines		69.00	69.00	S P Wood	1,034.32		1
23								
24								
25	46 Kv Lines		46.00	46.00	S P Wood	429.68		1
26								
27								
28								
29								
30								
31								
32								
33								
34	Expenses of all Lines							
35								
36					TOTAL	4,703.62	11.02	152

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
715.5 ACSR	1,174	212,777	213,951					1
250 COPPER	58	53,888	53,946					2
715.5 ACSR		76,560	76,560					3
397.5 ACSR		4,406	4,406					4
715.5 ACSR	1,074	253,872	254,946					5
397.5 ACSR	4,355	475,486	479,841					6
								7
715.5 ACSR	29,902	1,488,107	1,518,009					8
715.5 ACSR								9
								10
715.5 ACSR	7	152,852	152,859					11
715.5 ACSR	5,620	445,666	451,286					12
715.5 ACSR	2,814	183,606	186,420					13
397.5 ACSR	12,885	261,511	274,396					14
								15
								16
								17
397.5 ACSR	1,978	63,404	65,382					18
								19
								20
VARIOUS	858,879	30,340,629	31,199,508					21
VARIOUS								22
								23
								24
VARIOUS	176,265	7,420,974	7,597,239					25
								26
				5,502,879	3,017,527	2,176,624	10,697,030	27
								28
								29
								30
								31
								32
								33
								34
								35
	20,341,978	269,491,947	289,833,925	5,502,879	3,017,527	2,176,624	10,697,030	36

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Boise Bench	Butler	0.08	SP Wood	20.00	1	1
2	Eagle	Star		SP Wood			
3	Butler	Wye	3.00	SP Steel	22.00	1	1
4	Vallivie Tap		0.82	SP Steel	26.00	1	2
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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21							
22							
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34							
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36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		3.90		68.00	3	4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ACSR	Vert 6'	138	34,687	139,913	411,406		586,006	1
715	ACSR				1,040,488	47,480		1,087,968	2
795	ACSR	Vert 6'	138	471,769	682,759	376,280		1,530,808	3
795	ACSR	Vert 6'	138		272,092	79,405		351,497	4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
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									40
									41
									42
									43
				506,456	2,135,252	914,571		3,556,279	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.00	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.50
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bethel Court	distribution	138.00	13.00	
10	Black Cat	distribution	138.00	13.09	
11	Blackfoot	distribution	46.00	12.50	
12	Blackfoot	distribution	138.00	38.00	13.80
13	Bliss - attended	transmission	138.00	13.80	
14	Blue Gulch	distribution	138.00	34.50	
15	Boise Bench - attended	distribution	138.00	34.50	
16	Boise Bench - attended	transmission	138.00	69.00	13.80
17	Boise Bench - attended	transmission	230.00	138.00	13.80
18	Boise Cascade Emmett CSPP	distribution	69.00	13.00	
19	Boise	distribution	138.00	13.00	
20	Borah	transmission	345.00	230.00	13.80
21	Bowmont	distribution	69.00	46.00	6.90
22	Bowmont	distribution	138.00	34.50	
23	Bowmont	distribution	138.00	69.00	13.80
24	Brady	transmission	46.00	12.50	
25	Brady	transmission	230.00	138.00	13.80
26	Brownlee - attended	transmission	230.00	13.80	
27	Bruneau Bridge	distribution	138.00	34.50	
28	Buckhorn	distribution	69.00	35.00	
29	Bucyrus	distribution	46.00	7.20	
30	Buhl	distribution	46.00	13.00	
31	Burley Rural	distribution	69.00	13.00	
32	Butler	distribution	138.00	13.00	
33	Caldwell	distribution	138.00	13.00	
34	Caldwell	distribution	138.00	69.00	13.00
35	Caldwell	transmission	230.00	138.00	12.50
36	Canyon Creek	distribution	138.00	34.50	
37	Canyon Creek	distribution	138.00	69.00	12.50
38	Cascade Power Plant - attended	transmission	69.00	4.60	
39	Chestnut	distribution	138.00	13.00	
40	Clear Lake - attended	transmission	46.00	2.30	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
15	1					9
24	1					10
30	2					11
130	3	1				12
69	3					13
15	1					14
42	2					15
90	4					16
398	4					17
12	1					18
67	3					19
450	3	1				20
8	3					21
18	1					22
25	1					23
		6				24
300	3					25
734	5	1				26
30	2					27
20	1					28
13	4					29
20	2					30
12	1					31
48	2					32
39	2	1				33
50	2					34
240	2					35
15	1					36
		1				37
12	1					38
48	2					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Cliff	transmission	138.00	46.00	12.50
2	Cloverdale	transmission	138.00	13.00	
3	Cloverdale	transmission	138.00	69.00	12.50
4	Dale	distribution	69.00	13.00	
5	Dale	distribution	138.00	34.50	
6	Dale	distribution	138.00	46.00	12.50
7	Danskin	transmission	138.00	12.00	
8	Don	distribution	138.00	7.60	
9	Don	distribution	138.00	7.60	
10	Don	distribution	138.00	13.80	7.20
11	Don	distribution	138.00	13.80	
12	DRAM	distribution	138.00	13.00	
13	DRAM	distribution	230.00	138.00	13.80
14	Duffin	distribution	138.00	34.50	
15	Eagle	distribution	138.00	13.00	
16	Eastgate	distribution	138.00	13.00	
17	Eden	distribution	138.00	34.50	
18	Eden	distribution	138.00	46.00	12.50
19	Elkhorn	distribution	138.00	12.00	
20	Elmore	transmission	138.00	34.50	
21	Elmore	distribution	138.00	69.00	12.50
22	Emmett	distribution	138.00	12.50	
23	Emmett	distribution	138.00	69.00	12.50
24	Falls	distribution	46.00	12.50	
25	Filer	distribution	46.00	12.50	
26	Flying H	distribution	69.00	2.40	
27	Fort Hall	distribution	46.00	12.50	
28	Fossil Gulch	distribution	138.00	13.80	4.60
29	Fossil Gulch	distribution	138.00	34.50	
30	Fremont	transmission	138.00	46.00	12.50
31	Gary	distribution	138.00	13.00	
32	Gem	distribution	69.00	13.00	
33	Golden Valley	distribution	69.00	12.50	
34	Gowen Substation	distribution	138.00	36.00	
35	Grindstone	distribution	35.00	12.50	
36	Grove	distribution	138.00	12.50	
37	Hagerman	distribution	46.00	12.50	
38	Hailey	distribution	138.00	12.50	
39	Haven	distribution	46.00	34.50	
40	Hewlett Packard	distribution	138.00	13.10	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
33	4					1
48	2					2
50	2					3
		1				4
24	1					5
25	1					6
160	2					7
38	3	10				8
54	3					9
15	1					10
26	1					11
101	6					12
160	2					13
36	2					14
35	2					15
36	2					16
24	1					17
15	1					18
15	2					19
16	1					20
30	2					21
15	1					22
25	1					23
17	2					24
10	1					25
15	2					26
10	1					27
8	1					28
15	1					29
50	3	1				30
36	2					31
17	2					32
10	1	1				33
18	1					34
10	2					35
72	3					36
12	2					37
20	1					38
12	1					39
20	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	Hidden Springs	distribution	138.00	13.09	
2	Highland	distribution	138.00	13.09	
3	Hill	distribution	138.00	12.50	
4	Homedale	distribution	69.00	12.50	
5	Horseshoe Bend	distribution	35.00	12.50	
6	Horseshoe Bend	distribution	69.00	12.50	
7	Horseshoe Bend	distribution	69.00	25.00	
8	Houston	distribution	69.00	13.00	
9	Hulen	distribution	46.00	13.00	
10	Hunt	transmission	230.00	138.00	13.80
11	Hydra	distribution	138.00	34.50	
12	Island	distribution	69.00	12.50	
13	Jerome	distribution	138.00	12.50	
14	Julion Clawson	distribution	138.00	34.50	
15	Joplin	distribution	138.00	13.00	
16	Karcher	distribution	138.00	13.09	
17	Kenyon	distribution	69.00	12.50	
18	Ketchum	distribution	138.00	12.50	
19	Kinport	transmission	161.00	46.00	13.00
20	Kinport	transmission	230.00	138.00	12.50
21	Kinport	transmission	230.00	138.00	13.80
22	Kinport	transmission	345.00	230.00	13.80
23	Kramer	distribution	138.00	34.50	
24	Kramer	distribution	138.00	13.00	
25	Kuna	distribution	138.00	13.00	
26	Lamb	distribution	138.00	13.09	
27	Lansing	distribution	69.00	13.00	
28	Linden	distribution	138.00	13.00	
29	Locust	distribution	138.00	34.50	
30	Locust	transmission	230.00	138.00	13.00
31	Lower Malad - attended	transmission	138.00	7.20	
32	Lower Salmon - attended	transmission	138.00	13.80	
33	Map Rock	distribution	69.00	12.50	
34	McCall	distribution	69.00	12.50	
35	McCall	distribution	138.00	35.00	
36	McCall	distribution	138.00	69.00	12.50
37	Meridian	distribution	138.00	13.00	
38	Micron	distribution	138.00	12.50	
39	Midpoint	transmission	230.00	138.00	12.50
40	Midpoint	transmission	345.00	230.00	13.80

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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.
8	1					1
18	1					2
24	1					3
20	2					4
6	1					5
12	1					6
5	1					7
10	1					8
10	1	1				9
300	3					10
24	1					11
12	1					12
20	1					13
30	2					14
15	1					15
12	1					16
20	2					17
42	2					18
		7				19
180	1					20
180	1					21
600	3	1				22
12	1					23
18	1					24
15	1					25
15	1					26
12	1					27
33	2					28
48	2					29
360	2					30
15	1					31
70	4					32
10	1					33
8	1					34
18	1					35
30	1					36
36	2					37
48	4					38
120	1					39
720	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/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	Midpoint	transmission	500.00	345.00	
2	Midrose	distribution	138.00	13.09	
3	Milner	distribution	69.00	38.00	13.80
4	Milner	distribution	69.00	38.00	7.20
5	Milner	distribution	138.00	34.50	
6	Milner PP - attended	transmission	138.00	13.80	
7	Moonstone	distribution	138.00	34.50	
8	Mora	distribution	138.00	34.50	
9	Moreland	distribution	46.00	12.50	
10	Moreland	distribution	46.00	34.50	12.50
11	Mountain Home	distribution	69.00	12.50	
12	Mountain Home Air Force Base	distribution	69.00	12.50	
13	Mountain Home Air Force Base	distribution	138.00	12.50	
14	Nampa	distribution	230.00	138.00	
15	Nampa	distribution	138.00	12.50	
16	Nampa	distribution	138.00	69.00	12.50
17	New Meadows	distribution	69.00	35.00	
18	New Plymouth	distribution	69.00	12.50	
19	Parma	distribution	69.00	12.50	
20	Parma	distribution	69.00	34.50	
21	Paul	distribution	138.00	34.50	12.50
22	Payette	distribution	138.00	12.50	
23	Pingree	distribution	138.00	46.00	12.50
24	Pingree	distribution	138.00	36.00	
25	Pleasant Valley	distribution	138.00	34.50	
26	Pocatello	distribution	46.00	12.50	
27	Portneuf	distribution	138.00	36.20	
28	Portneuf	distribution	46.00	35.00	
29	Rockford	distribution	46.00	12.50	
30	Russett	distribution	138.00	12.50	
31	Sailor Creek	distribution	138.00	13.80	4.60
32	Sailor Creek	distribution	138.00	34.50	
33	Salmon	distribution	69.00	12.50	
34	Salmon	distribution	69.00	34.50	12.50
35	Shoshone	distribution	46.00	13.00	
36	Shoshone	distribution	46.00	7.20	
37	Shoshone Falls - attached	transmission	46.00	2.30	
38	Shoshone Falls - attached	transmission	46.00	6.60	
39	Silver	distribution	138.00	34.50	
40	Simplot	distribution	138.00	12.50	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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.
1000	4					1
18	1					2
75	3	1				3
8	3	1				4
16	1					5
36	1					6
12	1					7
33	2					8
8	1					9
10	3	1				10
12	1					11
		1				12
18	1					13
300	1					14
50	3					15
25	1					16
10	4					17
10	1					18
10	1					19
12	1					20
36	2					21
22	3					22
50	3					23
22	2					24
42	2					25
36	2					26
18	1					27
5	3	1				28
14	2					29
18	1					30
15	2					31
15	1					32
10	1	4				33
10	3	1				34
10	1	1				35
2	3					36
3	1					37
10	1					38
12	1					39
15	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/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	Sinker Creek	distribution	138.00	34.50	
2	Siphon	distribution	138.00	34.50	
3	South Park	distribution	46.00	13.00	
4	Star	distribution	69.00	13.00	
5	State	distribution	69.00	12.50	
6	Stoddard	distribution	138.00	13.00	
7	Strike Power Plant - attended	transmission	138.00	13.80	
8	Sugar	distribution	138.00	34.50	
9	Swan Falls - attended	transmission	138.00	6.90	
10	Taber	distribution	46.00	12.50	
11	Terry	distribution	138.00	12.50	
12	Thousand Springs - attended	transmission	46.00	6.90	
13	Thousand Springs - attended	transmission	7.00	2.40	
14	Toponis	distribution	138.00	34.50	
15	Twin Falls	distribution	138.00	13.00	
16	Twin Falls	distribution	138.00	46.00	12.50
17	Twin Falls PP - attended	transmission	138.00	7.20	
18	Twin Falls PP - attended	transmission	138.00	13.20	
19	Upper Malad - attended	transmission	46.00	7.20	
20	Upper Salmon- attended	transmission	138.00	7.20	
21	Ustick	distribution	138.00	12.50	
22	Valley View	distribution	138.00	13.09	
23	Victory	distribution	138.00	12.50	
24	Ware	distribution	69.00	12.50	
25	Weiser	distribution	69.00	12.50	
26	Weiser	distribution	138.00	69.00	12.50
27	Wilder	distribution	69.00	13.00	
28	Wye	distribution	138.00	13.00	
29	Zilog	distribution	69.00	12.50	
30					
31					
32	The above are all State of Idaho				
33					
34	Montana:				
35	Peterson	transmission	138.00	38.00	12.50
36					
37	Nevada:				
38	Valmy - attended	transmission	345.00	21.30	
39	Wells	transmission	138.00	69.00	12.50
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
33	2					2
10	1					3
12	1					4
33	2					5
15	1					6
83	3					7
10	1					8
18	1					9
5	1					10
42	3					11
8	1					12
2	1					13
18	1					14
40	2					15
33	2					16
9	1					17
72	1					18
8	1					19
36	4					20
44	2					21
18	1					22
24	1					23
10	1					24
20	2					25
25	1					26
10	1					27
56	3					28
25	2					29
						30
						31
						32
						33
						34
30	3	1				35
						36
						37
150	1					38
26	4					39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/22/2005	End of 2004/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Oregon:				
2	Boardman - attended	transmission	500.00	24.00	
3	Cairo	distribution	69.00	12.50	
4	Hells Canyon - attended	transmission	230.00	13.80	
5	Hines	transmission	138.00	115.00	12.50
6	Malheur Butte	distribution	69.00	34.50	12.50
7	Nyssa	distribution	69.00	12.50	
8	Ontario	distribution	138.00	12.50	
9	Ontario	distribution	138.00	69.00	12.50
10	Ontario	distribution	230.00	138.00	12.50
11	Ore-Ida	distribution	69.00	12.50	
12	Oxbow - attended	transmission	69.00	38.00	12.50
13	Oxbow - attended	transmission	230.00	13.80	
14	Oxbow - attended	transmission	230.00	138.00	13.80
15	Quartz	transmission	138.00	69.00	12.50
16	Quartz	transmission	138.00	80.00	12.50
17	Vale	distribution	69.00	13.09	
18					
19	Wyoming:				
20	Jim Bridger - attended	transmission	345.00	22.00	
21					
22					
23					
24					
25					
26					
27	Transformers-distribution substations under 10,000				
28	KVA 82 unattended.				
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/22/2005	Year/Period of Report End of 2004/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
55	1					2
12	1					3
500	3	1				4
40	1					5
10	3					6
20	2					7
38	2					8
65	3					9
240	2					10
15	1					11
10	3	1				12
244	2					13
100	1					14
30	2					15
133	4					16
10	1					17
						18
						19
748	1					20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

INDEX

Schedule	Page No.

INDEX (continued)

Schedule	Page No.

December 31, 2004

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122 for important notes regarding the state ment of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 756,779,337	$ 731,203,284
3	Operating Expenses			
4	Operation Expenses (401)	15	491,365,712	440,309,898
5	Maintenance Expenses (402)	15	54,187,809	57,428,728
6	Depreciation Expense (403)		84,052,059	80,134,589
7	Amort. & Depl. of Utility Plant (404-405)		9,092,999	8,841,860
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Regulatory Study Costs (407)			
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits (407.3)		19,944	
13	(Less) Regulatory Credits (407.4)		(18,949,682)	
14	Taxes Other Than Income Taxes (408.1)	2	17,219,724	18,563,551
15	Income Taxes - Federal (409.1)	2	17,839,912	47,464,805
16	- Other (409.1)	2	7,958,131	8,397,483
17	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	(18,569,538)	(24,823,835)
18	Investment Tax Credit Adj. - Net (411.4)	2	(1,042,465)	265,614
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23				
24	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		643,174,605	636,582,693
25				
26	Net Utility Operating Income (Enter Total of line 2 less 23)			
27	(Carry forward to page 11, line 27)		$ 113,604,732	$ 94,620,591

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 7,786,151
FUTA	129,008
State Unemployment	122,030
Payroll Deduction & Loading	(8,037,189)
Total Labor Related	0
Property Taxes	14,284,541
Kilowatt-hour Tax	1,090,597
Licenses	3,266
Regulatory Commission Fees	1,642,859
Irrigation PIC	198,460
Total Taxes Other Than Income Taxes	17,219,724
Federal Income Taxes	17,839,912
State Income Taxes	7,958,131
Deferred Income Taxes	(18,569,538)
Investment Tax Credit Adjustment - Net	(1,042,465)
Total Taxes Allocated to Idaho	$ 23,405,764

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	$ 12,982,368	$ 11,863,100
2	Customer Accounts Receivable (Account 142)	43,693,876	45,440,589
3	Other Accounts Receivable (Account 143)	4,840,398	5,201,303
4	(Disclose any capital stock subscription received)		
5	Total	61,516,641	62,504,992
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,465,615	1,363,426
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 60,051,025	$ 61,141,566
12			
13			
14	Notes Receivable - Account 141: (at 12-31-04)		
15	Directors, officers, and employees - $ 7,269,296		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-04)		
19	Directors, officers, and employees - $ 4,705		
20			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21						
22	Bal. beginning of year	$ 1,566,346	-	-	$ (256,433)	$ 1,309,913
23	Prov. for uncollectibles					
24	for year	100,731			(47,218)	53,513
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 1,667,077	$ -	$ -	$ (303,651)	$ 1,363,426
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.
2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12	Account 146:					
13						
14	Rocky Mountain Communication	$ 496,630.12	$ 3,965,422	$ 4,370,026	92,026	
15						
16	IDACORP, Inc.	$ 646,452.58	$ 51,707,422	$ 51,148,356	1,205,519	
17						
18	IDACORP Energy Solutions	$ -	$ 224,886	$ 224,479	407	
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ 1,143,083	$ 55,897,730	$ 55,742,861	$ 1,297,952	
32						

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STATE OF IDAHO - TOTAL SYSTEM DATA

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.

2. Individual gains or losses relating to property with an original cost of less than $50,000 may be grouped, with the number of such transactions disclosed in column (a).

3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	Stoddard Sub Excess Land Sale	$ 415,885		$ (254,712)	
5	BOBN Trans Stn Land Sale	830		(212,782)	
6					
7					
8					
9					
10					
11					
12	Miscellaneous items (2)			(1,764)	
13					
14	Total gain	$ 416,715		$ (469,258)	
15					
16	Loss on disposition of				
17	property:				
18	Homedate Operations Center Sale	$ 51,178			$ 7,207
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss	$ 51,178			$ 7,207

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ACCOUNTEMPS	Management Services	20,355
2	ADECCO	Mapping Services	52,840
3	AERO-GRAPHICS	Mapping Services	230,621
4	ALRUS CONSULTING	Govermental Relationship Services	14,000
5	ASHLEY LAND SERVICES	Environmental Services	15,098
6	AURORA CONSULTING GROUP	Management Services	172,185
7	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	88,525
8	BIDART & ROSS INC	Management Services	76,715
9	BLACKBURN & JONES LLP	Legal Services	293,596
10	BLANK & ASSOCIATES P.S.	Management Services	108,193
11	BLUE WORLD INFORMATION TECHNOL	Management Services	78,705
12	BOISE BUSINESS CONSULTING, INC	Management Services	209,980
13	BRICKLEY, SEARS & SORETT, P.A.	Legal Services	51,297
14	BROWN RUDNICK BERLACK ISRAELS	Legal Services	36,000
15	BROWNSTEIN HYATT & FARBER, P C	Environmental Services	441,196
16	BURKE CSA	Customer Service Survey	40,000
17	BURKE INCORPORATED	Customer Service Survey	135,000
18	BUSINESS LEGAL CONSULTING	Management Services	13,005
19	CARDWELL CONSULTING INC	Management Services	50,993
20	CH2M HILL	Engineering Services	61,887
21	CHARLES G FORSTER, P E	Engineering Services	11,479
22	CHARLES RIVER ASSOCIATES INCOR	Management Services	12,341
23	CHURCH, JOHN S	Economic Services	72,000
24	CITIGATE DATA CONSULTING, LLC	Management Services	12,769
25	COMMVAULT SYSTEMS, INC	Management Services	27,500
26	CONNOLLY & SMYSER, CHTD	Management Services	75,428
27	CORNERSTONE SYSTEMS INC	Computer Support Services	601,892
28	CRI ADVANTAGE	Computer Support Services	74,100
29	CYBERMATION INC	Computer Support Services	15,149
30	D J RESEARCH	Management Services	16,208
31	DAVIS WRIGHT TREMAINE LLP	Legal Services	913,362
32	DC ENGINEERING, PC	Engineering Services	26,844
33	DELOITTE & TOUCHE	Accounting Services	412,564
34	DELOITTE & TOUCHE LLP	Accounting Services	445,996
35	DELOITTE TAX LLP	Accounting Services	46,749
36	DESERET RESEARCH INSTITUTE	Management Services	175,109
37	DEVINE, TARBELL & ASSOC INC	Environmental Services	44,232
38	DHI INC	Environmental Services	45,427
39	ECOANALYSTS INC	Environmental Services	42,811
40	ENERGY INVESTMENTS MANAGEMENT,	Management Services	15,000
41	ENVIRONMENTAL ENGINEERING	Engineering Services	20,978
42	EOP GROUP	Govermental Relationship Services	270,000
43	ERNST & YOUNG LLP	Management Services	1,019,119
44	EVANS KEANE	Legal Services	24,479
45	F A DENBROCK, P.E.	Engineering Services	18,084

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
46	GJORDING & FOUSER, PLLC	Management Services	44,939
47	GJORDING, GARRETT & FOUSER	Management Services	12,643
48	HALL FARLEY OBERRECHT & B	Legal Services	135,128
49	HDR ENGINEERING, INC	Engineering Services	41,752
50	HDR INC	Engineering Services	17,597
51	HIRST, ERIC	Management Services	13,913
52	HOLLAND CONSULTING GROUP	Management Services	85,705
53	HUSTON DVM, RICHARD V	Management Services	15,991
54	INTERMOUNTAIN TECHNOLOGY GROUP	Computer Support Services	103,097
55	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	508,314
56	J D POWER AND ASSOCIATES	Management Services	27,000
57	JAMS INC	Management Services	18,390
58	JBR ENVIRONMENTAL CONSULTANTS	Environmental Services	18,432
59	JUB ENGINEERS	Engineering Services	91,575
60	KNOBLAUCH, WAYNE A	Management Services	22,228
61	LANE, V MICHAEL	Management Services	17,018
62	LE BOEUF LAMB GREENE	Management Services	1,751,643
63	LITCHFIELD CONSULTING GROUP	Management Services	17,762
64	MARSH ADVANTAGE AMERICA	Management Services	17,040
65	MARSHALL & ASSOCIATES	Management Services	64,520
66	MCFAIN & ASSOC RESEARCH INC	Customer Service Survey	23,160
67	MERCURY INTERACTIVE CORP	Computer Support Services	30,000
68	MERRILL & MERRILL CHARTERED	Legal Services	11,571
69	MILLER BATEMAN LLP	Legal Services	74,047
70	MOBLEY ENGINEERING INC	Engineering Services	48,088
71	NEXUS ENERGY SOFTWARE	Management Services	505,642
72	NIELSEN GROUP INC, THE	Customer Service Survey	403,155
73	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	43,649
74	PERKINS COIE LLP	Legal Services	130,863
75	POWER ENGINEERS INC	Engineering Services	20,117
76	POWERCET CORPORATION	Management Services	22,069
77	PRICEWATERHOUSE COOPERS LLP	Accounting Services	25,000
78	PUBLIC OPINION STRATEGIES LLC	Management Services	15,000
79	RALSTON & ASSOCIATES	Engineering Services	18,035
80	RIDDELL WILLIAMS P.S.	Legal Services	438,785
81	RIGHT MANAGEMENT CONSULTANTS	Management Services	15,000
82	RIGHT SYSTEMS, INC	Management Services	44,375
83	RIPLEY, LARRY D	Management Services	35,150
84	RIVERSIDE TECHNOLOGY INC	Environmental Services	52,797
85	ROBERT W WOOD, PC	Management Services	16,416
86	SALLADAY & DAVIS	Legal Services	185,987
87	SERVICE QUALITY MEASUREMENT GR	Customer Service Survey	15,289
88	SMITH, CURTIS D	Cloud Seeding Services	10,076
89	STATE OF IDAHO	Management Services	50,000

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
90	STEPTOE & JOHNSON LLP	Legal Services	425,699
91	STETSON P.E., LAVERNE E.	Management Services	10,771
92	STONE, R H	Management Services	40,670
93	SULLIVAN & CROMWELL	Legal Services	100,748
94	SUMMIT BLUE CONSULTING LLC	Legal Services	25,210
95	SUNGARD PLANNING SOLUTIONS	Management Services	20,193
96	THELEN REID AND PRIEST LLP	Legal Services	22,023
97	TREASURE VALLEY LEGAL SERVICES	Legal Services	46,618
98	TRIVUE	Management Services	46,230
99	UNIVERSITY OF IDAHO	Environmental Services	27,370
100	VAILE, SCOTLUND	Management Services	25,000
101	VAN NESS FELDMAN	Legal Services	567,264
102	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	11,900
103	VOITH HYDRO INC	Environmental Services	24,000
104	WEATHER MODIFICATION INC	Cloud Seeding Services	29,413
105	ZGA ARCHITECTS & PLANNERS	Architectural Services	18,354
106			
107			
108			
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PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	ATER, WYNNE LLP	Legal Services	$ 7,285
2	BOISE STATE UNIVERSITY	Management Services	5,870
3	COMPLIANCE SYSTEMS LEGAL GROUP	Legal Services	9,366
4	ENVENTURE, INC	Management Services	6,193
5	EQUENT INC	Management Services	6,938
6	ESRI INC	Geodata base Services	9,975
7	FIEDLER, FRITZ	Engineering Services	6,528
8	GENERAL ELECTRIC POWER SY	Management Services	5,830
9	ICF ENERGY SOLUTIONS, INC	Management Services	7,500
10	JEFFREY H BRAATNE PHD	Environmental Services	5,426
11	JONES, GLEDHILL, HESS, ANDREWS	Legal Services	8,073
12	MALGREN, KEN	Legal Services	6,248
13	MCCONNAUGHEY, DOUGLAS	Legal Services	7,500
14	MCMILLIAN ELDRIDGE	Management Services	5,831
15	MORGAN ANGEL & ASSOCIATES	Lobby Services	9,488
16	PARAGON CONSULTING SERVICES	Engineering Services	5,970
17	SMITHSONIAN INSTITUTE	Environmental Services	6,329
18	SPENCER CONSULTING	Management Services	5,580
19	SPF WATER ENGINEERING, LLC	Environmental Services	7,903
20	STATISTICAL DESIGN	Engineering Services	8,087
21	U S GEOLOGICAL SURVEY	Management Services	7,510
22	UTILITY RESOURCES	Management Services	5,050
23	WOOD CRAPO, LLC	Legal Services	6,375
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ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) . Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,180	
3	(302) Franchises and Consents	8,566,111	
4	(303) Miscellaneous Intangible Plant	56,635,603	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	65,206,894	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	722,319,606	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	579,376,950	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			$ 5,258	(301)	2
			9,375,034	(302)	3
			61,381,345	(303)	4
			70,761,637		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			2,558,441	(317)	15
			756,558,877		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			594,274,308		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 47,940,207	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,349,636,764	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	17,657,376	
49	(352) Structures and Improvements	25,510,923	
50	(353) Station Equipment	173,794,729	
51	(354) Towers and Fixtures	55,210,899	
52	(355) Poles and Fixtures	70,863,543	
53	(356) Overhead Conductors and Devices	85,947,993	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	250,695	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	429,236,159	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,624,498	
61	(361) Structures and Improvements	15,395,780	
62	(362) Station Equipment	119,482,754	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	164,829,925	
65	(365) Overhead Conductors and Devices	87,103,989	
66	(366) Underground Conduit	34,952,167	
67	(367) Underground Conductors and Devices	133,917,957	
68	(368) Line Transformers	240,553,773	
69	(369) Services	44,530,098	
70	(370) Meters	38,282,432	
71	(371) Installations on Customer Premises	2,034,861	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,759,099	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	888,467,332	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	7,811,992	
78	(390) Structures and Improvements	53,326,546	
79	(391) Office Furniture and Equipment	49,510,563	
80	(392) Transportation Equipment	39,249,328	
81	(393) Stores Equipment	882,399	
82	(394) Tools, Shop, and Garage Equipment	3,237,177	
83	(395) Laboratory Equipment	8,065,068	
84	(396) Power Operated Equipment	5,604,345	
85	(397) Communication Equipment	23,012,914	
86	(398) Miscellaneous Equipment	1,909,601	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	192,609,933	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	192,609,933	
91	TOTAL (Accounts 101 and 106)	2,925,157,082	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 2,925,157,082	

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	44
			$ 49,549,572		45
			1,400,382,756		46
					47
			18,967,406	(350)	48
			26,513,448	(352)	49
			192,783,834	(353)	50
			65,195,492	(354)	51
			74,353,999	(355)	52
			93,540,014	(356)	53
				(357)	54
				(358)	55
			258,820	(359)	56
				(359.1)	57
			471,613,012		58
					59
			3,236,450	(360)	60
			17,558,946	(361)	61
			121,883,650	(362)	62
				(363)	63
			169,651,555	(364)	64
			87,163,932	(365)	65
			38,597,249	(366)	66
			145,041,107	(367)	67
			247,888,244	(368)	68
			43,848,501	(369)	69
			45,244,916	(370)	70
			2,221,384	(371)	71
				(372)	72
			3,761,277	(373)	73
				(374)	74
			926,097,210		75
					76
			7,893,724	(389)	77
			55,505,835	(390)	78
			47,946,665	(391)	79
			40,408,870	(392)	80
			928,294	(393)	81
			3,533,350	(394)	82
			8,509,357	(395)	83
			5,830,803	(396)	84
			24,062,804	(397)	85
			2,161,775	(398)	86
			196,781,476		87
				(399)	88
				(399.1)	89
			196,781,476		90
			3,065,636,092		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 3,065,636,092		96

ELECTRIC OPERATING REVENUES (Account 400)

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

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 264,432,685	$ 266,499,664
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	237,670,029	254,652,452
5	Large (or Industrial)(See Instr. 4) (2)	103,211,741	121,183,306
6	(444) Public Street and Highway Lighting	2,194,234	2,517,165
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	607,508,689 *	644,852,588
11	(447) Sales for Resale - Opportunity....Non-Firm Only	110,451,320	54,894,912
12	TOTAL Sales of Electricity	717,960,009	699,747,500
13	(449.1) Provision for Rate Refunds	1,114,364	(1,514,466)
14	TOTAL Revenue Net of Provision for Refunds	719,074,373	698,233,034
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,177,891	3,353,527
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,096,192	15,356,794
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	17,430,881	14,259,926
22			
23			
24			
25	TOTAL Other Operating Revenues	37,704,963	32,970,248
26	TOTAL Electric Operating Revenues	$ 756,779,337	$ 731,203,282

(1) Commercial and Industrial sales - Small - under 1,000 KW and includes all irrigation customers.
(2) Commercial and Industrial sales - Large - 1,000 KW and over.

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

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

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,389,994,071	4,238,675,325	347,384	336,204	2
				3
5,092,937,686	5,120,316,621	67,638	66,047	4
3,064,574,997	2,963,550,790	112	107	5
27,037,680	28,536,450	480	392	6
				7
				8
				9
12,574,544,434 **	12,351,079,186	415,614	402,750	10
2,717,422,630	1,686,106,716	N/A	N/A	11
15,291,967,064	14,037,185,902	415,614	402,750	12
				13

* Includes $ (2,784,492) unbilled revenues.

** Includes 51,163,975 KWH relating to unbilled revenues.

Lines 11 through 21 are on an "allocated" basis.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,121,417	$ 798,177
5	(501) Fuel	92,660,616	86,820,441
6	(502) Steam Expenses	5,029,304	4,266,006
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	1,470,502	1,208,406
10	(506) Miscellaneous Steam Power Expenses	5,543,638	3,272,906
11	(507) Rents	671,368	534,110
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	106,496,845	96,900,046
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,701,548	1,880,434
16	(511) Maintenance of Structures	338,935	299,985
17	(512) Maintenance of Boiler Plant	11,943,969	11,515,052
18	(513) Maintenance of Electric Plant	4,886,517	5,244,350
19	(514) Maintenance of Miscellaneous Steam Plant	2,905,848	4,979,069
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,776,817	23,918,890
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	129,273,662	120,818,936
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	4,176,063	3,542,537
45	(536) Water for Power	3,794,616	3,516,608
46	(537) Hydraulic Expenses	6,416,142	5,202,095
47	(538) Electric Expenses	1,175,791	1,048,760
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,388,132	1,689,732
49	(540) Rents	358,887	346,459
50	TOTAL Operation (Enter Total of lines 44 thru 49)	18,309,631	15,346,192

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 999,707	$ 1,051,310
54	(542) Maintenance of Structures	949,154	1,100,162
55	(543) Maintenance of Reservoirs, Dams, and Waterways	975,013	736,904
56	(544) Maintenance of Electric Plant	2,140,578	2,411,961
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,495,950	2,072,061
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,560,401	7,372,398
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	25,870,033	22,718,590
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	370,143	441,175
63	(547) Fuel	4,590,362	5,228,350
64	(548) Generation Expenses	161,183	150,035
65	(549) Miscellaneous Other Power Generation Expenses	282,385	280,169
66	(550) Rents	0	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,404,073	6,099,730
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	217	-
70	(552) Maintenance of Structures	117,034	140,776
71	(553) Maintenance of Generating and Electric Plant	65,273	117,832
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	227,653	268,435
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	410,177	527,044
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	5,814,251	6,626,773
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	184,262,619	139,131,189
77	(556) System Control and Load Dispatching	100,474	23,068
78	(557) Other Expenses	38,808,432	66,928,328
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	223,171,525	206,082,585
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	384,129,470	356,246,884
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,709,826	1,315,730
84	(561) Load Dispatching	2,482,481	2,304,418
85	(562) Station Expenses	1,423,846	1,264,093
86	(563) Overhead Line Expenses	456,328	532,675
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	7,950,494	4,998,502
89	(566) Miscellaneous Transmission Expenses	15,028	232,057
90	(567) Rents	1,832,087	1,140,225
91	TOTAL Operation (Enter Total of lines 83 thru 90)	15,870,090	11,787,698
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	549,772	602,651
94	(569) Maintenance of Structures	0	277
95	(570) Maintenance of Station Equipment	2,541,620	2,189,417
96	(571) Maintenance of Overhead Lines	1,976,089	1,864,952
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	6,631	64,942
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	5,074,111	4,722,238
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	20,944,202	16,509,937
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,368,098	3,115,740

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 2,253,438	$ 2,099,164
106	(582) Station Expenses	891,829	801,475
107	(583) Overhead Line Expenses	3,194,716	3,088,077
108	(584) Underground Line Expenses	1,640,328	2,762,626
109	(585) Street Lighting and Signal System Expenses	143,396	121,784
110	(586) Meter Expenses	3,935,551	4,496,854
111	(587) Customer Installations Expenses	487,909	435,492
112	(588) Miscellaneous Distribution Expenses	4,664,454	5,364,414
113	(589) Rents	140,393	133,314
114	TOTAL Operation (Enter Total of lines 103 thru 113)	20,720,112	22,418,941
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	62,175	33,224
117	(591) Maintenance of Structures	0	20
118	(592) Maintenance of Station Equipment	2,752,978	2,689,054
119	(593) Maintenance of Overhead Lines	10,219,142	11,089,857
120	(594) Maintenance of Underground Lines	1,222,685	1,351,494
121	(595) Maintenance of Line Transformers	235,963	1,608,411
122	(596) Maintenance of Street Lighting and Signal Systems	468,812	356,209
123	(597) Maintenance of Meters	909,523	1,357,473
124	(598) Maintenance of Miscellaneous Distribution Plant	166,351	224,381
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	16,037,629	18,710,123
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	36,757,741	41,129,063
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	408,079	380,359
130	(902) Meter Reading Expenses	4,489,463	4,425,988
131	(903) Customer Records and Collection Expenses	8,910,379	8,332,812
132	(904) Uncollectible Accounts	2,850,386	3,811,198
133	(905) Miscellaneous Customer Accounts Expenses	(5,776)	120,411
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	16,652,531	17,070,768
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	306,135	390,866
138	(908) Customer Assistance Expenses	7,174,632	6,829,273
139	(909) Informational and Instructional Expenses	5,299	149
140	(910) Miscellaneous Customer Service and Informational Expenses	715,731	613,818
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	8,201,797	7,834,106
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	42,139,149	27,972,058
152	(921) Office Supplies and Expenses	13,713,290	12,519,423
153	(Less) (922) Administrative Expenses Transferred-Credit	(24,555,748)	(26,348,765)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 6,574,191	$ 4,914,854
156	(924) Property Insurance	2,979,099	3,581,993
157	(925) Injuries and Damages	5,585,966	3,596,141
158	(926) Employee Pensions and Benefits	24,852,207	25,612,849
159	(927) Franchise Requirements	2,075	2,725
160	(928) Regulatory Commission Expenses	3,301,815	2,670,019
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	110,224	516,752
163	(930.2) Miscellaneous General Expenses	1,825,509	1,696,069
164	(931) Rents	11,331	35,716
165	TOTAL Operation (Enter Total of lines 151 thru 164)	76,539,107	56,769,833
166	Maintenance		
167	(935) Maintenance of General Plant	2,328,674	2,178,034
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	78,867,780	58,947,867
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 545,553,521	$ 497,738,625

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1	Payroll Period Ended (Date)	December 31, 2004
2	Total Regular Full-Time Employees	1,757
3	Total Part-Time and Temporary Employees	45
4	Total Employees	1,802