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

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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UTILITIES COMMISSION

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Idaho Power Company	**End of** 2006/Q4

Deloitte

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UTILITIES COMMISSION

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, 2006, 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, 2006, 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, 2006, and the results of its operations and its cash flows for the year ended December 31, 2006, 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

February 28, 2007

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be 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 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 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).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

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

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

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

b) 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 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	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

e) The following format must be used for the CPA Certification Statement 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."

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

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC 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. The public reporting burden for the FERC 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: Information Clearance Officer); 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 Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

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 submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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 FERC 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. Commission 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.

EXCERPTS FROM THE LAW

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 with:

(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 shall 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 and 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 fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from 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 the 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 may prescribe the manner and FERC Form in which such reports salt 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 FERC Form or FERC 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

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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 2006/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070	
05 Name of Contact Person 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* (208) 388-2650	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/18/2007

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 Darrel Anderson 02 Title Senior VP of Admin Ser & CFO	03 Signature Darrel Anderson	04 Date Signed *(Mo, Da, Yr)* 04/18/2007

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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) 04/18/2007	Year/Period of Report End of 2006/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)
67	Substations	426-427	
68	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	04/18/2007	End of 2006/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 Administrative Services 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	04/18/2007	End of 2006/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	04/18/2007	End of 2006/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	J. LaMont Keen	450,000
3			
4	Sr Vice President, Administrative Services & CFO	Darrel T. Anderson	280,000
5			
6	Sr Vice President, Power Supply	James C. Miller	280,000
7			
8	Sr Vice President, General Counsel and Secretary	Thomas Saldin	265,000
9			
10	Sr Vice President, Delivery	Dan Minor	250,000
11			
12	Vice President, Regulatory Affairs	Ric Gale	200,000
13			
14	[redacted]	Dennis Gribble	178,000
15			
16	[redacted]	A. Bryan Kearney	90,000
17			
18	Vice President, Human Resources	Luci McDonald	175,000
19			
20	Vice President, Public Affairs	Greg Panter	175,000
21			
22	[redacted]	Steven R. Keen	210,000
23			
24	Vice President and Chief Risk Officer	Lori Smith	170,000
25			
26	Vice President, Engineering and Operations	Lisa Grow	150,000
27			
28	Vice President, Customer Service and Regional Ops	Warren Kline	150,000
29			
30	[redacted]	Naomi Crafton-Shankel	135,000
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FOOTNOTE DATA

Schedule Page: 104 Line No.: 14 Column: a

Appointed VP and Chief Information Officer June 1, 2006.
Relinquished Vice President and Treasurer June 1, 2006.

Schedule Page: 104 Line No.: 16 Column: a

Resigned as Vice President and Chief Information Officer June 1, 2006.

Schedule Page: 104 Line No.: 22 Column: a

Appointed Vice President and Treasurer June 1, 2006.
Also President of IDACORP Financial Services, appointed September 8, 1998.

Schedule Page: 104 Line No.: 30 Column: a

Appointed to newly created position September 21, 2006
Relinquished Director of Audit Services September 21, 2006.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	Christine King	AMI Semiconductor, Inc.
4		2300 Buckskin Rd M/S #3, Pocatello, Idaho 83201
5		
6	Jack K. Lemley	Lemley & Associates, Inc.
7		604 N. 16th, Boise, Idaho 83702
8		
9	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
10		
11	Jon H. Miller ***	P.O. Box 1557, Boise, Idaho 83701
12		
13	Peter S. O'Neill ***	100 N. 9th St., Suite 200, Boise, Idaho 83702
14		
15	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
16		
17	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
18		P.O. Box 70, Boise, Idaho 83707-0070
19		
20	Richard G. Reiten	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
21		Portland, Oregon 97204
22		
23	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
24		
25	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
26		
27	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
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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	04/18/2007	End of 2006/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.

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

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. Relicensing costs closed to accunt 302 - $2,667,162 for Mid Snake Power Plant-Idaho.

2. None

3. None

4. None

5. New Transmission Lines:
   Chestnut to Happy Valley - 138Kv line #471 2.78 miles
   Caldwell to Willis - 138Kv line #474 5.67 miles

   Additions to existing Lines:
   Nampa Tap 230 Kv line #711 3.12 miles
   Line 459 138Kv - Replaces portion of Line #202, 69Kv 5.16 miles

   Distribution Stations:
   Willis
   Cartwright
   Happy Valley
   Eckert

6. Issued $116,300,000 variable rate Pollution Control Revenue Bonds, maturing July 15, 2026. Commission authorization for IPUC IPC-E-06-14, OPUC UF4227 WPSC 20005-29-ES-06. For additional information see footnote for pages 256.1 line #8.

7. None

8. On December 29, 2006 a general wage increase of 3.0%.

9. See pages 123.10 to 123.19

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a number of changes in Major Security Holders in 2006. Top ten institutional shareholders list saw one change from 3rd quarter to 4th quarter. In 4th quarter Fisher Investments replaced Pzena Investment Management on the top ten list.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) ☒ An Original (2) ☐ A Resubmission	04/18/2007	End of 2006/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	3,586,503,680	3,479,972,995
3	Construction Work in Progress (107)	200-201	210,094,019	149,814,313
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,796,597,699	3,629,787,308
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,406,209,952	1,364,640,116
6	Net Utility Plant (Enter Total of line 4 less 5)		2,390,387,747	2,265,147,192
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)		2,390,387,747	2,265,147,192
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)		976,937	922,349
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	51,914,196	43,512,409
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)		3,696	1,025,159
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		28,039,959	27,337,666
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)		80,934,788	72,797,583
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,189,450	583,874
36	Special Deposits (132-134)		510,000	510,000
37	Working Fund (135)		57,850	42,750
38	Temporary Cash Investments (136)		1,157,000	48,687,442
39	Notes Receivable (141)		6,717,530	10,522,187
40	Customer Accounts Receivable (142)		54,218,159	49,830,007
41	Other Accounts Receivable (143)		10,081,728	6,860,636
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		968,073	833,238
43	Notes Receivable from Associated Companies (145)		9,154,480	0
44	Accounts Receivable from Assoc. Companies (146)		0	637,084
45	Fuel Stock (151)	227	15,173,831	11,494,190
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	36,762,206	28,705,792
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	2,316,011	1,745,428
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)		8,952,014	17,532,437
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	28,192
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		31,365,181	38,905,298
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	244,432
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)		176,687,367	215,496,511
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		9,786,336	11,128,248
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	378,846,883	418,241,190
73	Prelim. Survey and Investigation Charges (Electric) (183)		416,116	187,483
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)		361,477	300,821
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	124,388,934	82,087,452
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		14,760,653	14,032,339
82	Accumulated Deferred Income Taxes (190)	234	117,138,886	103,660,136
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		645,699,285	629,637,669
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,293,709,187	3,183,078,955

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/18/2007	end of 2006/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	530,757,435	483,707,552
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	354,624,872	321,453,283
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	49,451,103	39,802,850
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)	-5,737,123	-3,425,324
16	Total Proprietary Capital (lines 2 through 15)		1,024,876,392	937,318,466
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	955,460,000	955,460,000
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	31,585,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,097,272	3,325,109
24	Total Long-Term Debt (lines 18 through 23)		983,947,728	983,719,891
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)		665,706	1,191,411
29	Accumulated Provision for Pensions and Benefits (228.3)		100,944,157	13,361,444
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		1,227,492	0
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)		12,911,220	10,079,335
35	Total Other Noncurrent Liabilities (lines 26 through 34)		115,748,575	24,632,190
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		52,200,000	0
38	Accounts Payable (232)		83,697,801	77,435,649
39	Notes Payable to Associated Companies (233)		0	10,101,115
40	Accounts Payable to Associated Companies (234)		1,110,966	152,888
41	Customer Deposits (235)		1,125,192	1,103,299
42	Taxes Accrued (236)	262-263	40,225,757	72,183,706
43	Interest Accrued (237)		12,324,003	14,104,406
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/18/2007	end of 2006/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)		2,015,825	1,997,689
48	Miscellaneous Current and Accrued Liabilities (242)		21,779,126	17,834,534
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		1,462,637	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		215,941,307	194,913,286
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		26,085,511	19,427,988
57	Accumulated Deferred Investment Tax Credits (255)	266-267	69,113,142	68,786,273
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	25,567,500	67,672,479
60	Other Regulatory Liabilities (254)	278	225,731,042	276,567,305
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)		573,951,058	586,260,338
64	Accum. Deferred Income Taxes-Other (283)		32,746,932	23,780,739
65	Total Deferred Credits (lines 56 through 64)		953,195,185	1,042,495,122
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,293,709,187	3,183,078,955

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	930,618,611	849,075,951	183,552,357	228,581,120
3	Operating Expenses					
4	Operation Expenses (401)	320-323	566,729,405	505,272,123	117,304,233	125,858,524
5	Maintenance Expenses (402)	320-323	64,719,689	59,538,848	13,889,728	15,396,567
6	Depreciation Expense (403)	336-337	90,803,410	92,933,330	23,082,027	22,847,069
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	9,089,661	8,574,137	2,277,290	2,447,409
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)		10,391,371	16,191,442	5,312	-213,167
13	(Less) Regulatory Credits (407.4)			4,820,743		
14	Taxes Other Than Income Taxes (408.1)	262-263	18,661,413	20,856,185	2,704,436	4,056,843
15	Income Taxes - Federal (409.1)	262-263	52,572,378	64,853,588	-2,210,395	2,822,632
16	- Other (409.1)	262-263	5,194,257	8,931,316	-1,454,076	-1,528,126
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	-2,231,898	24,279,913	9,161,474	23,282,389
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	6,646,675	58,648,054	4,938,756	4,357,162
19	Investment Tax Credit Adj. - Net (411.4)	266	326,869	1,950,116	287,244	-108,747
20	(Less) Gains from Disp. of Utility Plant (411.6)		46,144			
21	Losses from Disp. of Utility Plant (411.7)			591		
22	(Less) Gains from Disposition of Allowances (411.8)		8,257,817	1,173,359		22,458
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)		801,283,196	738,716,710	160,102,836	190,476,092
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		129,335,415	110,359,241	23,449,521	38,105,028

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
930,618,611	849,075,951					2
						3
566,729,405	505,272,123					4
64,719,689	59,538,848					5
90,803,410	92,933,330					6
						7
9,089,661	8,574,137					8
-22,723	-22,723					9
						10
						11
10,391,371	16,191,442					12
	4,820,743					13
18,661,413	20,856,185					14
52,572,378	64,853,588					15
5,194,257	8,931,316					16
-2,231,898	24,279,913					17
6,646,675	58,648,054					18
326,869	1,950,116					19
46,144						20
	591					21
8,257,817	1,173,359					22
						23
						24
801,283,196	738,716,710					25
129,335,415	110,359,241					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	04/18/2007	End of 2006/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)		129,335,415	110,359,241	23,449,521	38,105,028
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,273,822	2,986,557	471,178	543,363
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,001,750	2,553,933	417,929	493,272
33	Revenues From Nonutility Operations (417)		117,924	125,826	22,623	46,669
34	(Less) Expenses of Nonutility Operations (417.1)		374,582	285,293	143,760	103,641
35	Nonoperating Rental Income (418)		-318	-1,036	14,991	-4,034
36	Equity in Earnings of Subsidiary Companies (418.1)	119	9,648,253	8,874,042	3,529,166	3,101,508
37	Interest and Dividend Income (419)		3,108,574	3,192,922	440,849	750,571
38	Allowance for Other Funds Used During Construction (419.1)		6,092,152	4,950,151	1,271,044	1,711,617
39	Miscellaneous Nonoperating Income (421)		5,189,612	5,069,732	1,341,555	1,200,886
40	Gain on Disposition of Property (421.1)		2,738	27,521		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,056,425	22,386,489	6,529,717	6,753,667
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			106,328		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	573,834	533,964	199,967	142,885
46	Life Insurance (426.2)		-547,211	95,508	-334,074	180,794
47	Penalties (426.3)		2,307			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,267,336	351,382	257,085	332,885
49	Other Deductions (426.5)		6,954,457	4,637,585	3,184,397	1,319,048
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,250,723	5,724,767	3,307,375	1,975,612
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	35,742	37,228	7,611	9,375
53	Income Taxes-Federal (409.2)	262-263	-4,206,660	1,042,859	-4,504,251	-1,238,911
54	Income Taxes-Other (409.2)	262-263	92,071	244,977	-81,029	41,294
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,234,191	1,213,137	329,507	339,566
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,955,602	1,817,329	494,429	473,869
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)		-4,800,258	720,872	-4,742,591	-1,322,545
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		20,605,960	15,940,850	7,964,933	6,100,600
61	Interest Charges					
62	Interest on Long-Term Debt (427)		53,744,453	53,339,531	13,265,582	13,547,882
63	Amort. of Debt Disc. and Expense (428)		1,023,500	1,262,733	250,756	257,590
64	Amortization of Loss on Reaquired Debt (428.1)		1,184,936	1,160,697	314,413	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	83,415	386,020		4,061
68	Other Interest Expense (431)	340	4,002,342	1,103,151	1,918,522	715,544
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,026,460	2,790,871	1,242,226	998,431
70	Net Interest Charges (Total of lines 62 thru 69)		56,012,186	54,461,261	14,507,047	13,816,820
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		93,929,189	71,838,830	16,907,407	30,388,808
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)		93,929,189	71,838,830	16,907,407	30,388,808

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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		319,909,317	307,634,073
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		84,280,936	62,964,788
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock $2.50 par Value		-51,109,347	(50,689,544)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-51,109,347	(50,689,544)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		353,080,906	319,909,317
	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	04/18/2007	End of 2006/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)		354,624,872	321,453,283
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		39,802,850	30,928,808
50	Equity in Earnings for Year (Credit) (Account 418.1)		9,648,253	8,874,042
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		49,451,103	39,802,850

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	93,929,189	71,838,830
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	90,803,410	92,933,330
5	Amortization of (see note)	[illegible]	14,986,104
6			
7			
8	Deferred Income Taxes (Net)	-9,599,987	-34,972,335
9	Investment Tax Credit Adjustment (Net)	326,869	1,950,117
10	Net (Increase) Decrease in Receivables	3,814,073	4,885,165
11	Net (Increase) Decrease in Inventory	-12,306,638	-9,430,070
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-24,376,845	34,355,903
14	Net (Increase) Decrease in Other Regulatory Assets	40,201,156	18,112,357
15	Net Increase (Decrease) in Other Regulatory Liabilities	-57,333,724	-10,837,689
16	(Less) Allowance for Other Funds Used During Construction	6,092,152	4,950,151
17	(Less) Undistributed Earnings from Subsidiary Companies	9,648,253	8,874,042
18	Other (provide details in footnote): (see note)	[illegible]	6,667,692
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	134,366,446	176,665,211
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-217,813,466	-183,073,929
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		-200,675
30	(Less) Allowance for Other Funds Used During Construction	4,026,460	2,790,871
31	Other (provide details in footnote): Sale of Emission Allowance	11,322,948	70,757,625
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-210,516,978	-115,307,850
35			
36	Acquisition of Other Noncurrent Assets (d)	-89,507	
37	Proceeds from Disposal of Noncurrent Assets (d)	34,919	
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)	-17,978,726	-85,333,932
45	Proceeds from Sales of Investment Securities (a)	20,777,593	120,025,599

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	551,536	1,116,424
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			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-207,221,163	-79,499,759
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	116,300,000	60,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	32,944,405	
67	Other (provide details in footnote):		
68	Capital Infusion	47,049,883	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	196,294,288	60,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-116,300,000	-60,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,939,991	-4,445,891
77			
78	Net Decrease in Short-Term Debt (c)		-10,368,593
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-51,109,346	-50,689,544
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	25,944,951	-65,504,028
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-46,909,766	31,661,424
87			
88	Cash and Cash Equivalents at Beginning of Period	49,314,066	17,652,643
89			
90	Cash and Cash Equivalents at End of period	2,404,300	49,314,067

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

Plant	$ 9,066,939
Regulatory Assets	2,193,160
Unamortized Debt Expense	2,130,563
Unamortized Discount	227,837
Water Rights	1,042,009
Total	$14,660,508

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

Other Non-cash Adj to Net Income	$ 133,562
Asset Impairment	2,046,713
Unbilled Revenues	7,540,117
Gain on Sale of Assets	(11,751,251)
Other Current Liabilities	(2,309,505)
Other Long Term Assets	3,332,238
Other Long-Term Liabilities	10,996,966
Total	$ 9,988,840

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

Other Long-Term assets	$(3,057,669)
Other Long- Term Liabilities	117,678
Total	$(2,939,991)

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Nature of Business

Idaho Power Company (IPC), a wholly-owned subsidiary of IDACORP Inc., (IDACORP) is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the 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.

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.

In December 2006, IPC adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132 (R)." This adoption resulted in a difference of generally accepted accounting principles (GAAP) and the accounting requirements of FERC. Under GAAP, the reduction of the minimum pension liability is recorded directly to accumulated other comprehensive income and under the accounting requirements of FERC, the reduction of the minimum pension liability is recorded through current year comprehensive income.

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, including those related to rate regulation, benefit costs, contingencies, litigation, asset impairment, income taxes, unbilled revenues and bad debt, 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.

Regulation of Utility Operations

IPC follows Statement of Financial Accounting Standards (SFAS) 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 application of SFAS 71 by IPC can result in IPC recording expenses in a period different than the period the expense would be recorded 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.

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 or over-recovered portion, is then included in the calculation of the next year's PCA.

The effects of applying SFAS 71 are discussed in more detail in Note 11 - "Regulatory Matters."

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.

Derivative Financial Instruments
Financial instruments such as commodity futures, forwards, options and swaps are used to manage exposure to commodity price risk in the electricity market. The objective of the risk management program is to mitigate the risk associated with the purchase and sale of electricity and natural gas. The accounting for derivative financial instruments that are used to manage risk is in accordance with the concepts established by SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

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 2.75 percent in 2006, and 2.91 percent in 2005.

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 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.

Revenues
Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-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.

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 2006 and 2005 were 7.6 percent and 7.4 percent, respectively. IPC's reductions to interest expense for AFDC were $4 million for 2006 and $3 million for 2005. Other income included $6 million and $5 million of AFDC for 2006 and 2005, respectively.

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
Effective January 1, 2006, IPC adopted SFAS No. 123 (revised 2004), "Share-Based Payment" (SFAS 123(R)) using the modified prospective application method. SFAS 123(R) changes measurement, timing and disclosure rules relating to share-based payments, requiring that the fair value of all share-based payments be expensed. The adoption of SFAS 123(R) did not have a material impact on IPC's financial statements for the year ended December 31, 2006.

IPC's Consolidated Statements of Income for the year ended December 31, 2005 do not reflect any changes from the adoption of SFAS 123(R). In those years, stock based employee compensation was accounted for under the recognition and measurement principles of Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees," and related interpretations.

The following table illustrates what net income and earnings per share would have been had the fair value recognition provisions of SFAS 123 been applied to stock-based employee compensation in 2005 and 2004 (in thousands of dollars, except for per share amounts):

		2005		2004
IPC				
Net income, as reported	$	71,839	$	70,608
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects		108		276
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects		568		977
Pro forma net income	$	71,379	$	69,907

For purposes of these pro forma calculations, the estimated fair value of the options, restricted stock and performance shares is amortized to expense over the vesting period. The fair value of the restricted stock and performance shares is the market price of the stock on the date of grant. The fair value of an option award is estimated at the date of grant using a binomial option-pricing model. Expense related to forfeited options is reversed in the period in which the forfeit occurs.

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 amounts related to pension plans. In 2006, IPC adopted SFAS 158 "Accounting for Pension and Postretirement Costs - an amendment of FAS 87, 88, 106, and 132(R)" which required the company to record additional amounts related to pension plans in other comprehensive income. SFAS 158 is discussed in more detail in Note 9. Prior to December 2005, other comprehensive income included the additional minimum liability related to 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:

		2006		2005
		(thousands of dollars)		
Unrealized holding gains on securities	$	1,311	$	2,725
Defined benefit pension plans		(7,048)		(6,150)
Total	$	(5,737)	$	(3,425)

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

Reclassifications
Certain items previously reported for years prior to 2006 have been reclassified to conform to the current year's presentation. Net income and shareholders' equity were not affected by these reclassifications.

New Accounting Pronouncements
FIN 48: In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" (FIN 48), to create a single model to address accounting for uncertainty in tax positions. FIN 48 prescribes a minimum recognition threshold that a tax position is required to meet before being recognized in a company's financial statements and also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006.

IPC will adopt FIN 48 in the first quarter of 2007, as required. The cumulative effect of adopting FIN 48 will be recorded as an adjustment to 2007 opening retained earnings. IPC has not yet completed its evaluation of the effects the adoption of FIN 48 will have on its financial position or results of operations.

SFAS 157: In September 2006, the FASB issued SFAS 157, "Fair Value Measurements." SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. IPC is currently evaluating the impact of adopting SFAS 157 on its financial statements.

SFAS 159: In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115" (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of SFAS No. 157, IPC is currently evaluating the impact of SFAS 159.

2. INCOME TAXES:

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

	2006	**2005**
	(thousand of dollars)	
Federal income tax expense at 35% statutory rate	$ 48,408	$ 39,861
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(3,377)	(3,106)
AFDC	(3,542)	(2,709)
Investment tax credits	(3,513)	(3,295)
Repair allowance	(2,450)	(1,750)
Removal costs	(1,912)	(1,490)
Pension accrual	1,902	1,276
Capitalized overhead costs	(2,940)	-
Tax accounting method change	6,122	-

Settlement of prior years' tax returns	(6,199)	(2)
State income taxes, net of federal benefit	6,501	6,847
Depreciation	5,757	5,603
Other, net	(378)	816
Total income tax expense	$ 44,379	$ 42,051
Effective tax rate	32.1%	36.9%

The items comprising income tax are as follows:

	2006	2005
	(thousands of dollars)	
Income taxes currently payable (receivable):		
Federal	$ 48,366	$ 65,896
State	5,286	9,177
Total	53,652	75,073
Income taxes deferred:		
Federal	(9,960)	(29,891)
State	360	(5,081)
Total	(9,600)	(34,972)
Investment tax credits:		
Deferred	3,840	5,374
Restored	(3,513)	(3,424)
Total	327	1,950
Total income taxe expense	$ 44,379	$ 42,051

Components of the net deferred tax liability are as follows:

	2006	2005
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 41,825	$ 41,627
Advances for construction	9,212	6,881
Deferred compensation	14,381	13,276
Emission allowances	12,175	27,380
Retirement benefits	26,392	-
Other	13,154	14,496
Total	117,139	103,660
Deferred tax liabilities:		
Property, plant and equipment	230,361	240,144
Regulatory assets	343,590	346,116
Conservation programs	4,437	5,705
PCA	8,384	17,410
Retirement benefits	18,055	-
Other	1,871	666
Total	606,698	610,041
Net deferred tax liabilities	$ 489,559	$ 506,381

Status of Audit Proceedings
In March 2005, the Internal Revenue Service (IRS) began its examination of IDACORP's 2001-2003 tax years. On October 13, 2006, the IRS issued its examination report and assessment for those years. With the exception of IPC's capitalized overhead costs method, discussed below, the IRS and IDACORP were able to settle all issues. The $1.6 million federal tax assessment for the settled issues was paid in November 2006. Interest charges and state income taxes have been accrued and are expected to be paid during 2007. Settlement of the agreed issues decreased 2006 income tax expense by $6.2 million at IPC as the assessed deficiency was less than amounts previously accrued.

The IRS disallowed IPC's capitalized overhead cost method for uniform capitalization (the simplified service cost method) on the basis that IPC's self-constructed assets were not produced on a "routine and repetitive" basis as defined by Rev. Rul. 2005-53. The disallowance resulted in a federal tax assessment of $45 million. In November 2006 IDACORP filed a formal protest and request for an appeals conference. Also in November 2006, IDACORP made a refundable deposit of the disputed tax with the IRS to stop the accrual of interest. In December 2006, the IRS examination team filed its rebuttal to IDACORP's protest. In January 2007, IDACORP was notified that its case has been assigned to the IRS Appeals Office. IDACORP cannot predict the timing or outcome of this process, but believes that an adequate provision for income taxes and related interest charges has been made for this issue.

The simplified service cost method was also used for IPC's 2004 tax year. While 2004 is not currently under examination, it is likely the IRS will take the same position for 2004 as it did for 2001-2003; however, it is not likely that this position will result in a federal income tax assessment primarily due to the mitigating effect of accelerated tax depreciation.

On July 7, 2006, the IRS issued its examination report for Bridger Coal Company's 2001-2003 tax years. Bridger Coal is a partnership investment owned one-third by IPC. The audit resulted in net favorable adjustments to Bridger Coal's tax returns for those years. As a result of the settlement, IPC was able to decrease 2006 income tax expense by $1.9 million.

In 2004, IPC settled federal income tax deficiencies for the years 1999 and 2000 related to its partnership investment in the Bridger Coal Company. Applicable state tax return amendments were completed in 2004 and settled. Finalization of these examinations resulted in deficiencies that were less than previously accrued, enabling IDACORP to decrease income tax expense by $1.7 million in 2004.

Capitalized overhead costs
Generally, section 263A of the Internal Revenue Code of 1986, as amended, requires the capitalization of all direct costs and indirect costs, including mixed service costs, which directly benefit or are incurred by reason of the production of property by a taxpayer. The simplified service cost method, a "safe harbor" method, is one of the methods provided by the section 263A treasury regulations for the calculation of mixed service cost capitalization. IPC adopted the simplified service cost method for both the self-construction of utility plant and production of electricity beginning with its 2001 federal income tax return.

On August 2, 2005, the IRS and the Treasury Department issued guidance interpreting the meaning of "routine and repetitive" for purposes of the simplified service cost and simplified production methods of the Internal Revenue Code section 263A uniform capitalization rules. The guidance was issued in the form of a revenue ruling (Rev. Rul. 2005-53) which is effective for all open tax years ending prior to August 2, 2005, and proposed and temporary regulations (the "Temporary Regulations") which are effective for tax years ending on or after August 2, 2005. Both pieces of guidance take a more restrictive view of the definition of self-constructed assets produced by a taxpayer on a "routine and repetitive" basis than did treasury regulations in effect at the time IPC changed to the simplified service cost method.

For IPC, the simplified service cost method produced a current tax deduction for costs capitalized to electricity production that are capitalized into fixed assets for financial accounting purposes. Deferred income tax expense had not been provided for this deduction because the prescribed regulatory tax accounting treatment does not allow for inclusion of such deferred tax expense in current rates. Rate regulated enterprises are required to recognize such adjustments as regulatory assets if it is probable that such amounts will be recovered from customers in future rates.

As discussed in "Status of Audit Proceedings" above, the IRS has disallowed IPC's use of the simplified service cost method for the tax years 2001-2003 on the basis of Rev. Rul. 2005-53. As a result, the IRS has assessed a $45 million tax liability. IDACORP is in the process of appealing the IRS's assessment. Because of the nature of the issue, IDACORP's exposure with respect to this matter may be less than the tax assessed plus applicable interest charges. Additionally, after resolution IDACORP will likely amend its 2005 federal income tax return and its 2005 method change application to account for the effects that such resolution has on IPC's new uniform capitalization method (discussed below). This amendment is not expected to have a material negative impact on IPC's consolidated financial position, results of operations, or cash flows.

With respect to tax year 2005 and future tax years, the Temporary Regulations, as drafted, preclude IPC from using the simplified service cost method for its self-constructed assets. Under the Temporary Regulations, IPC is required to use another allowable section 263A method for its indirect costs, including mixed service costs. As a result of the Temporary Regulations, IPC made changes to its overall section 263A uniform capitalization method of accounting. In September 2006, the changes were adopted with an automatic method change request included in 2005 federal income tax return. The uniform capitalization methodology adopted for 2005 and subsequent years involves the use of the specific identification, burden rate, and step-allocation methods of accounting. The methods used are allowable under both the final and temporary section 263A regulations.

As with the simplified service cost method, the new uniform capitalization methodology produces an annual tax deduction for costs that are not required to be capitalized under section 263A as well as costs capitalized into the production of electricity. The method, while producing a beneficial result, is not as favorable as the simplified service cost method. Changing the uniform capitalization method resulted in a net charge to IPC's 2006 income tax expense of $6.1 million. The estimated 2006 tax deduction produced a $3.3 million tax benefit for the year. The change in method did not have a material effect on IPC's 2006 cash flows. The accounting and regulatory treatment for the new method is the same as previously used for the simplified service cost method.

3. COMMON STOCK:

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.

In December 2006, IDACORP contributed $47 million of additional equity to IPC. No additional shares of IPC common stock were issued.

4. LONG-TERM DEBT

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

	2006	2005
	(thousands of dollars)	
First mortgage bonds:		
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	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
Total first mortgage bonds	785,000	785,000
Pollution control revenue bonds:		

Variable Auction Rate Series 2003 due 2024 (a)		49,800		49,800
Variable Auction Rate Series 2006 due 2026 (a)		116,300		-
6.05% Series 1996A due 2026		-		68,100
Variable Rate Series 1996B due 2026		-		24,200
Variable Rate Series 1996C due 2026		-		24,000
Variable Rate Series 2000 due 2027		4,360		4,360
Total pollution control revenue bonds		170,460		170,460
American Falls bond guarantee		19,885		19,885
Milner Dam note guarantee		11,700		11,700
Unamortized premium (discount) - net		(3,097)		(3,325)
Total long-term debt	$	983,948	$	983,720

(a) Humboldt County and Sweetwater County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2006, to $951.1 million.

At December 31, 2006, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2007	2008	2009	2010	2011	Thereafter
IPC	$ 81,064	$ 1,064	$ 81,064	$ 1,064	$ 121,064	$ 701,725

At December 31, 2006 and 2005, the overall effective cost of IPC's outstanding debt was 5.71 percent and 5.84 percent, respectively.

On October 3, 2006, IPC completed a tax-exempt bond financing in which Sweetwater County, Wyoming issued and sold $116.3 million aggregate principal amount of its Pollution Control Revenue Refunding Bonds Series 2006. The bonds will mature on July 15, 2026. The $116.3 million proceeds were loaned by Sweetwater County to IPC pursuant to a loan agreement, dated as of October 1, 2006, between Sweetwater County and IPC. On October 10, 2006, the proceeds of the new bonds, together with certain other moneys of IPC, were used to refund Sweetwater County's Pollution Control Revenue Refunding Bonds Series 1996A, Series 1996B and Series 1996C totaling $116.3 million. The regularly scheduled principal and interest payments on the Series 2006 bonds, and principal and interest payments on the bonds upon mandatory redemption on determination of taxability, are insured by a financial guaranty insurance policy issued by AMBAC Assurance Corporation. IPC and AMBAC have entered into an Insurance Agreement, dated as of October 3, 2006, pursuant to which IPC has agreed, among other things, to pay certain premiums to AMBAC and to reimburse AMBAC for any payments made under the policy. To secure its obligation to make principal and interest payments on the loan made to IPC, IPC issued and delivered to a trustee IPC's First Mortgage Bonds, Pollution Control Series C, in a principal amount equal to the amount of the new bonds.

Long-Term Financing

IPC has in place a registration statement that can be used for the issuance of an aggregate principal amount of $240 million of first mortgage bonds (including medium-term notes) and unsecured debt.

In January 2007, the IPC Board of Directors approved an increase of the maximum amount of first mortgage bonds issuable by IPC to $1.5 billion. The amount issuable is also restricted by property, earnings and other provisions of the mortgage and supplemental indentures to the mortgage. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. The indenture requires that IPC's net earnings must be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that IPC may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

As of December 31, 2006, IPC could issue under the mortgage approximately $559 million of additional first mortgage bonds based on unfunded property additions and $452 million of additional first mortgage bonds based on retired first mortgage bonds. At December 31, 2006, unfunded property additions were approximately $1.0 billion.

The mortgage requires IPC to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement or amortization of its properties. IPC may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

The mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority or distinction. IPC may issue additional first mortgage bonds in the future, and those first mortgage bonds will also be secured by the mortgage. The lien of the indenture constitutes a first mortgage on all the properties of IPC, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of IPC are subject to easements, leases, contracts, covenants, workmen's compensation awards and similar encumbrances and minor defects and clouds common to properties. The mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The mortgage creates a lien on the interest of IPC in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger or sale of all or substantially all of the assets of IPC.

5. 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 are based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2006		December 31, 2005	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(thousands of dollars)		
Assets:				
Notes receivable	$ 5,853	$ 5,679	$ 7,047	$ 6,876
Investments	28,040	28,040	21,137	21,137
Liabilities:				
Long-term debt	$ 987,045	$ 978,491	$ 987,045	$ 1,003,651

6. NOTES PAYABLE:

IPC has a $200 million credit facility that expires on March 31, 2010. Commercial paper may be issued up to the amounts supported by the bank credit facilities. Under this facility the company 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. At December 31, 2006, IPC had regulatory authority to incur up to $250 million of short-term indebtedness. Balances and interest rates of IPC's short-term borrowings were as follows at December 31 (in thousands of dollars):

	2006	2005
	(thousands of dollars)	
Balances:		
At the end of year	$ 52,200	$ -
Average during the year	$ 14,211	$ 123
Weighted-average interest rate:		
At the end of year	5.50%	-
Average during the year	5.50%	3.83%

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations:
As of December 31, 2006, IPC had agreements to purchase energy from 92 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 that it has the ability to receive at the facility's requested point of delivery on the IPC system. IPC purchased 911,132 megawatt-hours (MWh) at a cost of $54 million in 2006 and 715,209 MWh at a cost of $46 million in 2005.

At December 31, 2006, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2007	2008	2009	2010	2011	Thereafter
			(thousands of dollars)			
Cogeneration and small power production	$ 45,130	$ 76,538	$ 76,538	$ 79,830	$ 79,830	$ 1,064,718
Power and transmission rights	80,175	16,351	7,390	2,781	2,754	13,315
Fuel	54,395	30,035	28,885	2,941	3,821	11,005

Guarantees
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, 2006. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company and IPC expect 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.

Legal Proceedings
From time to time IDACORP and IPC are a party to legal claims, actions and complaints in addition to those discussed below. IDACORP and IPC believe that they have meritorious defenses to all lawsuits and legal proceedings. Although they will vigorously defend against them, they are unable to predict with certainty whether or not they will ultimately be successful. However, based on the companies' evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IDACORP's or IPC's 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 U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. Wah Chang appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit on March 10, 2005. The Ninth Circuit set a briefing schedule on the appeal, requiring Wah Chang's opening brief to be filed by July 6, 2005. On May 18, 2005, Wah Chang filed a motion to stay the appeal or in the alternative to voluntarily dismiss the appeal without prejudice to reinstatement. The companies opposed the motion and filed a cross-motion asking the Court to summarily affirm the district court's order of dismissal. On July 8, 2005, the Ninth Circuit denied Wah Chang's motion and also denied the companies' motion for summary affirmance without prejudice to renewal following the filing of Wah Chang's opening brief. Wah Chang's opening brief was filed on September 21, 2005. On October 11, 2005 the companies, along with the other defendants, filed a motion to consolidate this appeal with Wah Chang v. Duke Energy Trading and Marketing currently pending before the Ninth Circuit. On October 18, 2005, the Ninth Circuit granted the motion to consolidate and established a revised briefing schedule. The companies filed an answering brief on November 30, 2005. Wah Chang's reply brief was filed on January 6, 2006.

The appeal has been fully briefed and oral argument is scheduled for April 10, 2007. The companies intend to vigorously defend their position in this proceeding and believe this matter 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 U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. The City of Tacoma appealed to the U.S. Court of Appeals for the Ninth Circuit on March 10, 2005.

On August 9, 2005, the companies moved for summary affirmance of the district court's order dismissing the City of Tacoma's complaint. The City of Tacoma filed a response to the companies' motion for summary affirmance on August 24, 2005. The Ninth Circuit denied the companies' motion for summary affirmance on November 3, 2005. The appeal has been fully briefed and oral argument is scheduled for April 10, 2007. The companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Western Energy Proceedings at the FERC:

<u>California Power Exchange Chargeback:</u>

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. The CalPX owed 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 believed that the default invoices were not proper and that IPC owed no further amounts to the CalPX. IPC 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.

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 claimed it would await further orders from the FERC and the bankruptcy court before distributing the funds that it collected under its chargeback tariff mechanism. 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. On March 15, 2005, the FERC issued an order on rehearing confirming that the CalPX was to continue to hold the chargeback funds, but solely to offset seller-specific shortfalls in the seller's CalPX account at the conclusion of the California refund proceeding. Balances were to be returned to the respective sellers at the conclusion of a seller's participation in the refund proceeding.

Based upon the Offer of Settlement filed with the FERC on February 17, 2006 between the California Parties and IE and IPC discussed below in "California Refund," the California Parties supported a motion filed by IE and IPC with the FERC seeking an Order Directing Return of Chargeback Amounts then held by the CalPX totaling $2.27 million. In the May 22, 2006 order approving the Settlement, the FERC granted the IE and IPC motion for return of chargeback funds held by the CalPX. On June 1, 2006, IE received approximately $2.5 million from the CalPX representing the return of $2.27 million in chargeback funds plus interest.

<u>California Refund:</u>
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).

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, were expected to increase the offsets to amounts still owed by the Cal ISO and the CalPX to the companies. Calculations remained uncertain because (1) the FERC had required the Cal ISO to correct a number of defects in its calculations, (2) it was unclear what, if any, effect the ruling of the Ninth Circuit in Bonneville Power Administration v. FERC, described below, might have on the ISO's calculations, and (3) the FERC had stated that if refunds would prevent a seller from recovering its California portfolio costs during the Refund Period, it would provide an opportunity for a cost showing by such a respondent.

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.

Two avenues of activity have proceeded on largely but not entirely independent paths, converging from time to time. The Cal ISO continued to work on its compliance refund calculations while the appellate litigation and litigation before the FERC regarding, among other things, cost filings, fuel cost allowance offsets, emissions offsets, cost-based recovery offsets, and allocation methods continued.

Originally, the Cal ISO was to complete its calculation within five months of the FERC's October 16, 2003, order. The Cal ISO compliance filing has since been delayed numerous times. The Cal ISO has been required to update the FERC on its progress monthly. In its most recent status report, filed February 22, 2007, the Cal ISO reported that it has completed publishing settlement statements reflecting the basic refund calculations, and is currently in a "financial adjustment" phase, in which it calculates adjustments to its refund data to account for fuel cost allowance offsets, emissions offsets, cost-based recovery offsets, and interest on amounts unpaid and refunds. The Cal ISO estimates that it will take approximately 10 additional weeks to complete the financial adjustment phase, including applicable review and comment periods. The Cal ISO estimates that it will have completed its calculations by May 2007, subject to such additional time as may be required if unanticipated delays are encountered. The potential expansion of the FERC refund proceedings due to the Ninth Circuit orders and the disposition of additional settlements which the Ninth Circuit has announced it expects to be filed at the FERC in the near future may affect the finality of any Cal ISO calculations. At present, IDACORP and IPC are not able to predict when the Ninth Circuit mandates may issue, how the FERC will proceed in connection with the possible expansion of the proceedings, the nature and content of as yet un-filed settlements or the extent to which the Cal ISO calculation process may be disrupted.

On December 2, 2003, IDACORP 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 cases related to: (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. Oral argument was held on April 12-13, 2005. On September 6, 2005, the Ninth Circuit issued a decision on the jurisdictional issues concluding that the FERC lacked refund authority over wholesale electric energy sales made by governmental entities and non-public utilities. On August 2, 2006, the Ninth Circuit issued its decision on the appropriate temporal reach and the type of transactions subject to the FERC refund orders and concluded, among other things, that all transactions at issue in the case that occurred within or as a result of the CalPX and the Cal ISO were the proper subject of refund proceedings; refused to expand the refund proceedings into the bilateral markets including transactions with the California Department of Water Resources; approved the refund effective date as October 2, 2000, but also required the FERC to consider whether refunds, including possibly market-wide refunds, should be required for an earlier time due to claims that some market participants had violated governing tariff obligations (although the decision did not specify when that time would start, the California Parties generally had sought further refunds starting May 1, 2000); and effectively expanded the scope of the refund proceeding to transactions within the CalPX and Cal ISO markets outside the 24-hour spot market and energy exchange transactions. The IDACORP settlement with the California Parties approved by the FERC on May 22, 2006, and discussed below anticipated the possibility of such an outcome and attempted to provide that the consideration exchanged among the settling parties also encompass the settling parties' claims in the event of such expansion of the proceedings.

The Ninth Circuit subsequently issued orders deferring the time for seeking rehearing of its order and holding the consolidated petitions for review in abeyance for a limited time in order to create an opportunity for unusual mediation proceedings managed jointly by the Court Mediator and FERC officials. The Ninth Circuit has since extended the deferral for the mediation effort.

IDACORP believes that these decisions should have no material effect on IDACORP under the terms of the IDACORP Settlement with the California Parties approved by the FERC on May 22, 2006.

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 approximately $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 with the Ninth Circuit. These petitions have since been consolidated with the larger number of review petitions in connection with the California refund proceeding.

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 remanding 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. On December 28, 2006, a number of sellers have filed a certiorari petition to the U.S. Supreme Court. The U.S. Supreme Court has not yet acted on that petition. On February 16, 2007, the Ninth Circuit announced that it was continuing to withhold the mandate until April 27, 2007.

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, 2005, 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.

On August 8, 2005, the FERC issued an Order establishing the framework for filings by sellers who elected to make a cost showing. On September 14, 2005, IE and IPC made a joint cost filing, as did approximately thirty other sellers. On October 11, 2005, the California entities filed comments on the IE and IPC cost filing and those made by other parties. IPC and IE submitted reply comments on October 17, 2005. The California entities filed supplemental comments on October 24, 2005 and IPC and IE filed supplemental reply comments on October 27, 2005.

In December of 2005, IE and IPC reached a tentative agreement with the California Parties settling matters encompassed by the California Refund proceeding including IE's and IPC's cost filing and refund obligation. On January 20, 2006, the Parties filed a request with the FERC asking that the FERC defer ruling on IE's and IPC's cost filing for thirty days so the parties could complete and file the settlement agreement with the FERC. On January 26, 2006, the FERC granted the requested deferral of a ruling on the cost filing and required that the settlement be filed by February 17, 2006. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. Other parties had until March 9, 2006 to elect to become additional settling parties. A number of parties, representing substantially less than the majority potential refund claims, chose to opt out of the settlement.

On March 27, 2006, the FERC issued an order rejecting the IE/IPC cost filing and on April 26, 2006, IE and IPC sought rehearing of the rejection. By order of April 27, 2006, the FERC tolled the time for what otherwise would have been required by statute to be a decision on the request for rehearing.

On May 12, 2006, the FERC issued an order determining the method that should be used to allocate amounts approved in cost filings, approving the methodology that IE and IPC and others had advocated prior to the time IE and IPC entered into the February 17, 2006 settlement – allocating cost offsets to buyers in proportion to the net refunds they are owed through the Cal ISO and CalPX markets. On June 12, 2006, the California Parties requested rehearing, urging the FERC to allocate the cost offsets to all purchasers from the Cal ISO and CalPX markets and not just to that limited subset of purchasers who are net refund recipients. On July 12, 2006, the FERC tolled the time to act on the request for rehearing and has not issued orders on rehearing since that time. IDACORP and IPC are unable to predict how or when the FERC might rule on the request for rehearing.

After consideration of comments, the FERC approved the February 17, 2006, Offer of Settlement on May 22, 2006. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IDACORP. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the settlement. On July 10, 2006, IPC and IE and the California Parties filed a response to Port of Seattle's request for rehearing. On October 5, 2006, the FERC issued an order denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC order denying their request for rehearing of the FERC order approving the settlement. The Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it. On January 23, 2007, IPC and IE filed a motion to sever the Port of Seattle's petition for review from the bulk of cases pending in the Ninth Circuit with which it had been consolidated. IPC and IE also filed a motion to dismiss the Port of Seattle's petition for review. The Port of Seattle filed their answers in opposition to the motion to sever and the motion to dismiss on February 1, 2007, and IPC and IE replied on February 12, 2007. IDACORP and IPC are not able to predict when or how the Ninth Circuit might rule on the motions.

Prior to December of 2005, IE had accrued a reserve of $42 million. This reserve was calculated taking into account the uncertainty of collection from the CalPX and Cal ISO. In the fourth quarter of 2005, following the tentative agreement with the California Parties, IE reduced this reserve by $9.5 million to $32 million. Following payment of the $10.25 million to IE and IPC in June 2006, IE further reduced the reserve by $24.9 million to $7.1 million. This reserve was calculated taking into account several unresolved issues in the California refund proceeding.

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 only 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 January 1, 2000 through the beginning of the existing refund period (October 2, 2000) 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. Originally, eight parties requested rehearing of the FERC's March 3, 2004 order. 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 Ninth Circuit has consolidated this case with other matters and are holding them in abeyance. IPC is not able to predict the outcome of the judicial determination of these issues.

The settlement between the California Parties and IE and IPC discussed above in the California Refund proceeding approved by the FERC on May 22, 2006, results in the California Parties and other settling parties withdrawing their requests for rehearing of IPC's and IE's settlement with the FERC Staff regarding allegations of "gaming". On October 11, 2006, the FERC issued an Order denying rehearing of its earlier approval of the "gaming" allegations, thereby effectively terminating the FERC investigations as to IPC and IE regarding bidding behavior, physical withholding of power and "gaming" without finding of wrongdoing. On October 24, 2006, the Port of Seattle appealed the FERC order to the U.S. Court of Appeals for the Ninth Circuit.

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. In March 2005, the California Attorney General, the CPUC, the California Electricity Oversight Board and Pacific Gas and Electric Company sought judicial review in the Ninth Circuit of the FERC's termination of this investigation as to IPC and approximately 30 other market participants. IPC has moved to intervene in these proceedings. On April 25, 2005, Pacific Gas and Electric Company sought review in the Ninth Circuit of another FERC order in the same docketed proceeding confirming the agency's earlier decision not to allow the participation of the California Parties in what the FERC characterized as its non-public investigative proceeding.

Pacific Northwest Refund:
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 intervened in this FERC proceeding, asserting on March 3, 2003 that its six-month forward contract, for which performance had been completed, should be treated as a spot market contract for purposes of the FERC's consideration of refunds and requested 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 these claims 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 sought to intervene in the proceedings initiated by the petitions of others. On July 21, 2004, the City of Seattle submitted 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 sought to introduce before the FERC consisted of audio tapes of what purports to be Enron trader conversations containing inflammatory language. 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. 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. Briefing was completed on May 25, 2005, and oral argument was held on January 8, 2007. The Settlement approved by the FERC on May 22, 2006, resolves all claims the California Parties have against IE and IPC in the Pacific Northwest refund proceeding. The settlement with Grays Harbor resolves all claims Grays Harbor has against IE and IPC in this proceeding. IE and IPC are unable to predict the outcome as to all other parties in this proceeding.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006 reviewing the FERC's decisions not to require repricing of certain long term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. IDACORP and IPC are unable to predict whether parties to that case will seek a writ of certiorari or how or when the FERC might respond to these decisions.

Shareholder Lawsuit: 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 IDACORP'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 account 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 IDACORP'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 alleged 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 IE financial outlook, in violation of Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. The new complaint alleged 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 IE in order to report higher revenues and profits; (2) IDACORP permitted IPC to inappropriately grant native load priority for certain energy transactions to IE; (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 IE 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 IE provided appropriate compensation from IE to IPC for certain affiliated energy transactions; and (6) IDACORP permitted inappropriate sharing of certain energy pricing and transmission information between IPC and IE. These activities allegedly allowed IE 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, and the plaintiffs filed their opposition to the consolidated motion to dismiss on March 28, 2005. IDACORP and the other defendants filed their response to the plaintiff's opposition on April 29, 2005 and oral argument on the motion was held on May 19, 2005.

On September 14, 2005, Magistrate Judge Mikel H. Williams of the U.S. District Court for the District of Idaho issued a Report and Recommendation that the defendants' motion to dismiss be granted and that the case be dismissed. The Magistrate Judge determined that the plaintiffs did not satisfactorily plead loss causation (i.e., a causal connection between the alleged material misrepresentation and the loss) in conformance with the standards set forth in the recent United States Supreme Court decision of Dura Pharmaceuticals, Inc. v. Broudo, 544 U.S.336, 125 S. Ct. 1627 (2005). The Magistrate Judge also concluded that it would be futile to afford the plaintiffs an opportunity to file an amended complaint because it did not appear that they could cure the deficiencies in their pleadings. Each party filed objections to different parts of the Magistrate Judge's Report and Recommendation.

On March 29, 2006, the U.S. District Court for the District of Idaho (Judge Edward J. Lodge) issued an Order in this case (Powell v. IDACORP) adopting the Report and Recommendation of Magistrate Judge Williams issued on September 14, 2005, granting the defendants' (IDACORP and certain of its officers and directors) motion to dismiss because plaintiffs failed to satisfy the pleading requirements for loss causation. However, Judge Lodge modified the Report and Recommendation and ruled that plaintiffs had until May 1, 2006, to file an amended complaint only as to the loss causation element. On May 1, 2006, the plaintiffs filed an amended complaint. The defendants filed a motion to dismiss the amended complaint on June 16, 2006, asserting that the amended complaint still failed to satisfy the pleading requirements for loss causation. Briefing on this most recent motion to dismiss was completed on August 28, 2006, and oral argument was held on February 26, 2007.

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

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants.

Plaintiffs allege that IPC's ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860's or before. Although it is unclear from the complaint, it appears plaintiffs' claims relate primarily to lands within the state of Nevada. Plaintiffs seek a judgment declaring their title to land and other resources, disgorgement of profits from the sale or use of the land and resources, a decree declaring a constructive trust in favor of the plaintiffs of IPC's assets connected to the lands or resources, an accounting of money or things of value received from the sale or use of the lands or resources, monetary damages in an unspecified amount for waste and trespass and a judgment declaring that IPC has no right to possess or use the lands or resources.

On May 1, 2006, IPC filed an Answer to plaintiffs' First Amended Complaint denying all liability to the plaintiffs and asserting certain affirmative defenses including collateral estoppel and res judicata, preemption, impossibility and impracticability, failure to join all real and necessary parties, and various defenses based on untimeliness. On June 19, 2006, IPC filed a motion to dismiss plaintiffs' First Amended Complaint, asserting, among other things, that the Court lacks subject matter jurisdiction and that plaintiffs failed to join an indispensable party (namely, the United States government). Briefing on the motion to dismiss was completed on September 28, 2006. Newly decided authority from the United States Court of Federal Claims in further support of IPC's motion to dismiss was filed on January 3, 2007. The Court has yet to act on the IPC motion to dismiss. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter.

Sierra Club Lawsuit - Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming for alleged violations of the Clean Air Act's opacity standards (alleged violations of air pollution permit emission limits) at the Jim Bridger coal fired plant ("Plant") in Sweetwater County, Wyoming. IPC has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of violations and seeks declaratory and injunctive relief and civil penalties of $32,500 per day per violation as well as the costs of litigation, including reasonable attorney fees. IPC believes there are a number of defenses to the claims and intends to vigorously defend its interest in this matter, but is unable to predict its outcome and is unable to estimate the impact this may have on its consolidated financial positions, results of operations or cash flows.

8. STOCK-BASED COMPENSATION:

IDACORP has three share-based compensation plans. IDACORP's employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth. IDACORP also has one non-employee plan, the Director Stock Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based compensation.

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2006, the maximum number of shares available under the LTICP and RSP were 1,688,562 and 104,325, respectively.

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

	2006	2005
Compensation cost	$ 1,458	$ 178
Income tax benefit	$ 570	$ 70

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and charged to compensation expense over the vesting period based on the number of shares expected to vest.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. For awards granted prior to 2006, dividends were paid to recipients at the time they were paid on the common stock. Beginning with the 2006 awards, dividends are accumulated and will be paid out only on shares that eventually vest.

The performance goals for the 2006 awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of restricted stock and performance share activity is presented below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	Number of Shares	Weighted-average Grant date Fair value
Nonvested shares at December 31, 2004	120,323	$ 30.27
Shares granted	87,620	29.75
Shares forfeited	(24,804)	38.40
Shares vested	(251)	31.21
Nonvested shares at December 31, 2005	182,888	$ 28.92
Shares granted	112,146	25.91
Shares forfeited	(91,538)	26.14
Shares vested	(19,200)	30.39
Nonvested shares at December 31, 2006	184,296	$ 28.32

At December 31, 2006, IDACORP had $1.9 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. IPC's share of this amount was $1.7 million. These costs are expected to be recognized over a weighted-average period of 1.91 years. IDACORP uses original issue and/or treasury shares for these awards.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. Upon adoption of SFAS 123(R) on January 1, 2006, the fair value of each option is amortized into compensation expense using graded-vesting. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

The fair values of all stock option awards have been estimated as of the date of the grant by applying a binomial option pricing model. The application of this model involves assumptions that are judgmental and sensitive in the determination of compensation expense. The following key assumptions were used in determining the fair value of options granted:

	2006	2005
Dividend yield, based on current dividend and stock price on grant date	3.7%	4.1%
Expected stock price volatility, based on IDACORP historical volatility	18%	23%
Risk-free interest rate based on U.S. Treasury composite rate	4.92%	4.22%
Expected term based on the SEC "simplified" method	6.50 years	7 years

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

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2004	952,600	$ 32.38	5.24	$ 6,371
Granted	157,837	29.75		
Exercised	-	-		

Forfeited	(16,300)		30.27			
Expired	-		-			
Outstanding at December 31, 2005	1,094,137	$	32.03	5.64	$	7,634
Granted	-		-			
Exercised	(320,821)		29.83			
Forfeited	(142,625)		28.51			
Expired	(11,600)		39.89			
Outstanding at December 31, 2006	619,091	$	33.84	5.71	$	3,385
Vested or expected to vest at December 31, 2006	603,152	$	33.97	5.67	$	3,227
Exercisable at December 31, 2006	407,826	$	36.44	5.04	$	1,292

The following table presents information about options granted and exercised (in thousands of dollars, except for weighted-average amounts):

	IPC	
	2006	2005
Weighted-average grant-date fair value	$ -	$ 5.95
Fair value of options vested	1,275	1,390
Intrinsic value of options exercised	2,883	-
Cash received from exercises	9,614	-
Tax benefits realized from exercises	1,127	-

As of December 31, 2006, there was $0.3 million of total unrecognized compensation cost related to stock options. These costs are expected to be recognized over a weighted average period of 2.51 years. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

9. BENEFIT PLANS:

SFAS 158

In December 2006 IPC adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R)."

The following table presents the incremental effect of applying SFAS 158 on individual line items in the Consolidated Balance Sheets of IPC at December 31, 2006:

	Before Application of Statement 158	Adjustments	After Application of Statement 158
		(thousands of dollars)	
Prepayments	$ 13,444	$ (4,136)	$ 9,308
Noncurrent regulatory assets	377,367	46,181	423,548
Other current assets	42,979	(1,720)	41,259
Total assets	3,404,805	40,325	3,445,130
Other current liabilities	21,197	2,375	23,572
Noncurrent deferred income taxes	504,260	(5,748)	498,512
Other liabilities	133,122	46,714	179,836
Total other liabilities	940,999	40,966	981,965

Accumulated other comprehensive income (loss)	(2,721)	(3,016)	(5,737)
Total shareholders' equity	1,127,199	(3,016)	1,124,183

In accordance with regulatory accounting treatment under SFAS 71, amounts that otherwise would have been recorded in accumulated other comprehensive income have been recorded as regulatory assets for both the pension and postretirement plans.

The measurement provisions of SFAS 158 are not required to be adopted until 2008 and require that a company measure its plan assets and benefit obligations as of its balance sheet date. IPC already uses a December 31 measurement date for its plans, so adoption of the measurement provisions of SFAS 158 is not expected to have a material effect on IPC's results of operations or cash flows.

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 2006 or 2005. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, 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.

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

	Pension Plan		Deferred Compensation Plan	
	2006	**2005**	**2006**	**2005**
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 406,049	$ 374,333	$ 42,723	$ 38,645
Service cost	14,476	13,129	1,473	1,170
Interest cost	22,340	21,126	2,327	2,151
Actuarial loss (gain)	(2,827)	11,399	(2,857)	2,799
Benefits paid	(14,439)	(13,938)	(2,352)	(2,312)
Plan amendments	-	-	552	270
Benefit obligation at December 31	425,599	406,049	41,866	42,723
Change in plan assets:				
Fair value at January 1	368,053	356,217	-	-
Actual return on plan assets	47,310	25,774	-	-
Employer contributions	-	-	-	-
Benefit payments	(14,439)	(13,938)	-	-
Fair value at December 31	400,924	368,053	-	-
Unfunded status at end of year	(24,675)	(37,996)	(41,866)	(42,723)
Unrecognized actuarial loss	-	43,806	-	13,553
Unrecognized prior service cost	-	5,118	-	1,414
Net amount recognized	$ (24,675)	$ 10,928	$ (41,866)	$ (27,756)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ -	$ -	$ (2,375)	$ -

Noncurrent liabilities		(24,675)		-		(39,491)		-
Prepaid (accrued) pension cost		-		10,928		-		(39,268)
Intangible asset		-		-		-		1,414
Accumulated other comprehensive income		-		-		-		10,098
Net amount recognized	$	(24,675)	$	10,928	$	(41,866)	$	(27,756)
Amounts recognized in accumulated other comprehensive income consist of:								
Net loss	$	24,356		-	$	9,853		-
Prior service cost		4,455		-		1,720		-
Subtotal		28,811		-		11,573		-
Less amount recorded as regulatory asset		(28,811)		-		-		-
Net amount recognized in accumulated other comprehensive income	$	-		-	$	11,573		-
Accumulated benefit obligation	$	350,434	$	340,007	$	38,634	$	39,268

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

	Pension Plan				Deferred Compensation Plan			
	2006		2005		2006		2005	
	(thousands of dollars)							
Service cost	$	14,476	$	13,129	$	1,473	$	1,170
Interest cost		22,340		21,126		2,327		2,151
Expected return on assets		(30,817)		(29,690)		-		-
Amortization of net loss		129		-		844		689
Amortization of prior service cost		664		771		245		228
Amortization of transition asset		-		(126)		-		310
Net periodic pension cost	$	6,792	$	5,210	$	4,889	$	4,548

Changes in the Deferred Compensation Plan minimum liability increased other comprehensive income by $2 million in 2006 (prior to the effect of adopting SFAS 158), decreased other comprehensive income by $1 million in 2005.

In 2007, IPC expects to recognize as components of net periodic benefit cost $1.4 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2006, relating to the pension and deferred compensation plans. This amount consists of $0.6 million of prior service cost for the pension plan and $0.6 million of net loss and $0.2 million of prior service cost for the deferred compensation plan.

The following table summarizes the expected future benefit payments of these plans:

	2007	2008	2009	2010	2011	2012-2016
Pension Plan	$ 15,070	$ 16,127	$ 17,354	$ 18,858	$ 20,462	$ 133,740
Deferred Compensation Plan	$ 2,438	$ 2,546	$ 2,797	$ 2,997	$ 3,059	$ 16,963

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2006 and 2005, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2006	2005	2006	2005

Equity securities	68%	66%	-%	-%
Debt securities	24	21	-	-
Real estate	7	10	-	-
Other (a)	1	3	100	100
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	5%	Short-Term Bonds	10%
Small-Cap Value Stocks	5%	Core Real Estate	9%
Micro-Cap Stocks	3%	Private Equity	2%
Cash and Cash Equivalents	3%		

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.

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

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. Benefits for employees who retire after December 31, 2002, are limited to a fixed amount, which 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):

	2006	2005
Service cost	$ 1,463	$ 1,392
Interest cost	3,426	3,381
Expected return on plan assets	(2,523)	(2,486)
Amortization of unrecognized transition obligation	2,040	2,040
Amortization of prior service cost	(535)	(535)
Amortization of net loss	812	754
Net periodic postretirement benefit cost	$ 4,683	$ 4,546

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

	2006	2005
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 63,633	$ 71,105
Service cost	1,463	1,392
Interest cost	3,426	3,381
Actuarial (gain) loss	(2,445)	(9,186)
Benefits paid	(3,164)	(2,934)
Plan amendments	-	(125)
Benefit obligation at December 31	62,913	63,633
Change in plan assets:		
Fair value of plan assets at January 1	29,893	29,723
Actual return on plan assets	3,158	1,127
Employer contributions	2,004	800
Benefits paid	(2,428)	(1,757)
Fair value of plan assets at December 31	32,627	29,893
Funded status at end of year	(30,286)	(33,740)
Unrecognized prior service cost	-	(3,677)
Unrecognized actuarial loss	-	15,978
Unrecognized transition obligation	-	14,280
Accrued benefit obligations included in noncurrent liabilities	$ (30,286)	$ (7,159)

Amounts recognized in accumulated other comprehensive income consist of:

Net loss	$ 12,086
Prior service cost (credit)	(3,142)
Transition obligation	12,240
Subtotal	21,184
Less amount recognized in regulatory assets	(17,370)
Less amount included in deferred tax assets	(3,814)
Net amount recognized in accumulated other comprehensive income	$ -

In 2007, IPC expects to recognize as components of net periodic benefit cost $2.0 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2006 relating to the postretirement plan. This amount consists of $0.5 million of net loss, ($0.5) million of prior service cost and $2.0 million of transition obligation.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and established a prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage. The measure of net periodic benefit cost for the year ended December 31, 2004 does not reflect any amount associated with the subsidy.

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

	2007	2008	2009	2010	2011	2012-2016
Expected benefit payments*	$ 4,100	$ 4,200	$ 4,300	$ 4,500	$ 4,700	$ 25,300
Expected Medicare Part D subsidy receipts	$ 600	$ 600	$ 700	$ 800	$ 800	$ 3,200

*Expected benefit payments are net of expected Medicare Part D subsidy receipts.

The assumed health care cost trend rate used to measure the expected cost of benefits covered by the plan was 6.75 percent in 2006 and 2005. 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	1-Percentage-Point decrease
Effect on total of cost components	$ 258	$ (195)
Effect on accumulated postretirement benefit obligation	$ 2,409	$ (1,897)

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	
	2006	2005	2006	2005
Discount rate	5.85%	5.6%	5.85%	5.6%
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	11

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

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
Discount rate	5.6%	5.75%	5.6%	5.75%
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	11

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 $4 million in both 2006 and 2005.

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. The post employment benefit amounts included in other deferred credits on IPC's consolidated balance sheets at December 31 are $4.0 million and $3.8 million for 2006 and 2005, respectively.

10. 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 2006 and 2005 (in thousands of dollars):

	2006		2005	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,592,790	2.55%	$ 1,563,008	2.54%
Transmission	606,947	2.18	580,382	2.19
Distribution	1,097,390	2.60	1,046,880	2.62
General and Other	286,567	6.74	286,797	8.94
Total in service	3,583,694	2.75%	3,477,067	2.91%
Accumulated provision for depreciation	(1,406,210)		(1,364,640)	
In service - net	$ 2,177,484		$ 2,112,427	

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, 2006 (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	$ 468,032	$ 7,890	$ 270,302	33	707
Boardman	Boardman, OR	69,109	476	47,284	10	59
Valmy Units 1 and 2	Winnemucca, NV	316,075	10,527	203,188	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. IPC's coal purchases from the joint venture were $52 million and $43 million in 2006 and 2005, respectively.

IPC has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. IPC's power purchases from these facilities were $8 million in 2006 and $7 million annually in 2005.

11. REGULATORY MATTERS:

Regulatory Assets and Liabilities

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

As of December 31, 2006

As of

Description	Remaining Amortization Period	Earning a Return	Not Earning a Return	Pending Regulatory Treatment	2006 Total	December 31, 2005 Total
Regulatory Assets:						
Income Taxes		$ -	$ 343,590	$ -	$ 343,590	$ 346,117
SFAS 158 (1)		-	46,181	-	46,181	-
Conservation	2010	11,349	-	-	11,349	14,592
PCA Deferral		-	-	-	-	32,251
Oregon Deferral (2)		9,559	-	-	9,559	11,291
Asset Retirement Obligations (3)		-	11,206	-	11,206	8,363
Tax Settlement Order		-	-	-	-	4,994
Grid West Loans		56	932	302	1,290	-
Other	Various thru 2008	390	1,463	-	1,853	633
Total		$ 21,354	$ 403,372	$ 302	$ 425,028	$ 418,241
Regulatory Liabilities:						
Income Taxes		$ -	$ 41,825	$ -	$ 41,825	$ 41,627
Conservation	2007	6,328	-	-	6,328	6,535
PCA Accrual (4)	2007	(11,852)	27,025	-	15,173	-
Asset Retirement Obligations (3)		-	156,162	-	156,162	152,683
Deferred ITC		-	69,114	-	69,114	68,786
IPUC Settlement Order		-	-	-	-	4,021
BPA Settlement		2,124	-	-	2,124	1,393
Emission Allowance		-	-	4,118	4,118	70,034
Other	Various thru 2007	-	-	-	-	30
Total		$ (3,400)	$ 294,126	$ 4,118	$ 294,844	$ 345,109

(1) See Note 9
(2) Capped at 10 percent increase per year.
(3) See Note 14
(4) Includes $69 million of emission allowances, of which $42.1 million earns a return and $27.0 million does not.

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.

Deferred Power Supply Costs
Idaho: 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.

Idaho Load Growth Adjustment Rate (LGAR): In April 2006 IPC filed a petition with the IPUC requesting modification of one component of its PCA referred to as the Load Growth Adjustment Rate. The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs IPC is allowed to include in its PCA.

The LGAR was set at $16.84 per megawatt-hour when the PCA began in 1993. This amount was established as the projected marginal cost of serving each new customer and is subtracted from each year's PCA expense. In its April 2006 petition, IPC requested using the embedded cost of serving the new load rather than the projected marginal cost and to lower the rate to $6.81 per megawatt-hour. The IPUC Staff recommended against changing to the embedded cost approach; IPUC Staff also recommended increasing the rate to $40.87 per megawatt hour.

On January 9, 2007, the IPUC issued its final order in this matter. The IPUC maintained the marginal cost methodology and set the new LGAR at $29.41 per megawatt-hour. The new rate becomes effective on April 1, 2007 and will first affect customer rates on June 1, 2008.

The impact of the new LGAR on IPC will ultimately be determined by future load growth. Assuming an average 40 megawatt load growth, the new rate would result in approximately $10.3 million subtracted from the next PCA, a pre-tax increase of $4.4 million over the current amount. The impact of the new LGAR can be partially offset by IPC through more frequent general rate case filings with the IPUC or from less customer growth. In its order the IPUC stated that it expected IPC to update its load growth adjustment in all future general rate cases.

Oregon: The timing of recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. For the 2005-2006 deferral, a settlement stipulation drafted by the OPUC Staff provides that, instead of being amortized into rates, the deferral should be offset with the Oregon jurisdictional share of proceeds from the sale of SO2 emission allowances and the benefit that IPC will receive from income taxes already paid on the sale of those allowances. An order is expected from the OPUC during the first quarter of 2007.

Emission Allowances: During 2005 and 2006, IPC sold 78,000 SO2 emission allowances for approximately $81.6 million (before income taxes and expenses) on the open market. After subtracting transaction fees, the total amount of sales proceeds to be allocated to the Idaho jurisdiction was approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). The IPUC allowed IPC to retain ten percent, or approximately $4.7 million after tax, of the emission allowance net proceeds as a shareholder benefit. The remaining 90 percent of the sales proceeds ($69.1 million) plus a carrying charge will be recorded as a customer benefit. This customer benefit will be reflected in PCA rates during the June 1, 2007, through May 31, 2008, PCA rate year. The carrying charge will be calculated on $42.1 million, the net-of-tax amount allocable to Idaho jurisdiction customers.

As discussed above, a stipulation is currently before the OPUC which would offset SO2 emission allowance proceeds against the 2005-2006 balance of Oregon deferred power supply costs. The stipulation allows for IPC to retain ten percent of the proceeds from emission allowance sales as a shareholder benefit.

Through allowance year 2006, IPC has approximately 36,000 excess allowances.

Deferred (Accrued) Net Power Supply Costs:
IPC's deferred net power supply costs consisted of the following at December 31 (in thousands of dollars):

	2006	2005
Idaho PCA current year:		
Deferral for the 2006-2007 rate year	$ -	$ 3,684
Accrual for the 2007-2008 rate year*	(3,484)	-
Idaho PCA true-up awaiting recovery (refund):		
Authorized May 2005	-	28,567
Authorized May 2006	(11,689)	-
Oregon deferral:		
2001 costs	6,670	8,411
2005 costs	2,889	2,880

Total (accrual) deferral	$	(5,614)	$	43,542

*Includes $69 million of emission allowance sales to be credited to the customers during the 2007-2008 PCA year

Fixed Cost Adjustment Mechanism (FCA)
On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent from the volume of IPC's energy sales. This filing is a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The first FCA rate change under this proposal would occur on June 1, 2007, coincident with IPC's PCA rate change. The accounting for the FCA will be separate from the PCA. As part of the filing, IPC proposes a three percent cap on any rate increase to be applied at the discretion of the IPUC.

On March 6, 2006, the IPUC reviewed IPC's proposal and acknowledged the intent of IPC and the IPUC Staff to initiate and engage in settlement discussions. The IPUC Staff presented an alternate view of IPC's proposal. Three workshops were held in 2006 and the parties have agreed in concept to a three-year pilot beginning at the first of the year and a stipulation was filed December 18, 2006. The stipulation calls for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of DSM activities. The pilot program began on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. The deadline for filing written comments with respect to the stipulation and the use of modified procedure was January 31, 2007. A final order is expected from the IPUC in the first quarter of 2007.

12. INVESTMENTS:

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

		2006		2005
Investments:				
Equity method investment	$	62,223	$	38,764
Available-for-sale equity securities		21,548		21,137
Executive deferred compensation		6,492		6,201
Other investments		4		1,025
Total investments		90,267		67,127

Equity Method Investments
IPC, through its subsidiary Idaho Energy Resources Co., 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):

		2006		2005
Bridger Coal Company	$	9,347	$	10,369

The following table presents summarized income statement information for Bridger Coal Company (in thousands of dollars):

		2006		2005
Operating revenues	$	154,910	$	128,015
Operating expenses		126,869		96,909
Net Income	$	28,041	$	31,106

The following table presents summarized balance sheet information for Bridger Coal Company (in thousands of dollars):

	2006	2005
Assets		
Current assets	$ 47,723	$ 26,442
Noncurrent assets	325,252	262,909
Total Assets	$ 372,975	$ 289,351
Liabilities		
Current liabilities	$ 28,250	$ 17,728
Noncurrent liabilities	158,054	155,330
Total Liabilities	186,304	173,058
Joint venture capital	186,671	116,293
Total Liabilities and Joint Venture Capital	$ 372,975	$ 289,351

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.

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

	2006			2005		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 2,474	$ 322	$ 21,548	$ 2,925	$ 497	$ 21,137

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

	2006	2005	2004
Proceeds from sales	$ 20,778	$ 120,026	$ 266,331
Gross realized gains from sales	3,774	2,850	2,044
Gross realized losses from sales	280	643	634

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 has not recognized any other-than-temporary impairments in 2006 or 2005.

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).

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	Aggregate Related Fair Value	Aggregate Unrealized Loss	Aggregate Related Fair Value
2006:				
Available for sale equity securities	$ 241	$ 3,879	$ 81	$ 621
2005:				
Available for sale equity securities	$ 215	$ 1,731	$ 282	$ 1,423

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. At December 31, 2006, 11 available-for-sale in an unrealized loss position. None of these securities had unrealized loss positions of greater than 20 percent. At December 31, 2005, nine available-for-sale were in an unrealized loss position. Two available-for-sale securities had unrealized loss positions of greater than 20 percent. IPC does not consider these investments to be other-than-temporarily impaired at December 31, 2006 or 2005.

13. ASSET RETIREMENT OBLIGATIONS:

On January 1, 2003, IPC adopted SFAS 143, "Accounting for Asset Retirement Obligations," requiring legal obligations associated with the retirement of property, plant and equipment to be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under SFAS 143, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, 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.

On December 31, 2005, IPC adopted FIN 47, which clarifies the scope and timing of liability recognition for conditional asset retirement obligations (AROs). The interpretation requires that a liability be recorded for the fair value of an ARO, if the fair value is estimable, even when the obligation is dependent on a future event. FIN 47 further clarified that uncertainty surrounding the timing and method of settlement of the obligation should be factored into the measurement of the conditional ARO rather than affect whether a liability should be recognized.

Upon adoption of FIN 47, two AROs were identified at IPC. The obligations at IPC are the result of PCB removals at its distribution facilities and the reclamation and removal costs of one of its jointly owned coal-fired generation facilities. These AROs were recorded in March 2006 when they became measurable. IPC recorded an ARO liability of $2.2 million, fixed assets of $0.5 million, accumulated depreciation of $0.4 million and a regulatory asset of $2.1 million.

Other AROs previously identified and recorded under FAS 143 relate to removal costs identified at two of IPC's jointly owned coal-fired generation facilities. IPC has AROs associated with its transmission system and hydro facilities, however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of 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, 2006, IPC had $156 million of such costs recorded as regulatory liabilities on its Consolidated Balance Sheet.

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

	2006	2005
Balance at beginning of year	$ 10,079	$ 9,288

Accretion expense		628		531
Revisions in estimated cash flows		-		260
Liability incurred		2,204		-
Balance at end of year	$	12,911	$	10,079

14. RELATED PARTY TRANSACTIONS (IPC):

IDACORP

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 in 2006 and 2005 for these services.

IDACOMM

IPC provides project management and engineering services to IDACOMM. IDACOMM also pays joint use fees to IPC. Total fees charged to IDACOMM were $0.1 million in 2006 and $0.3 million in 2005.

Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects. IPC paid $8 million in 2006 and $7 million per year in 2005 and 2004.

15. OTHER INCOME AND EXPENSE:

The following table presents the components of Other Income and Other Expense (in thousands of dollars):

		2006		2005
Other income:				
Allowance for funds used during construction-equity	$	6,092	$	4,950
Investment income, net		8,489		6,424
Gain on extinguishment of debt		-		-
Other		3,614		5,747
Total	$	18,195	$	17,121
Other expense:				
Security plan pension expense	$	4,889	$	4,548
Other		3,670		3,458
Total	$	8,559	$	8,006

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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 Year	(4,537,792)	5,425,566		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	1,355,332			
3	Preceding Quarter/Year to Date Changes in Fair Value	457,455	724,764		
4	Total (lines 2 and 3)	1,812,787	724,764		
5	Balance of Account 219 at End of Preceding Quarter/Year	(2,725,005)	6,150,330		
6	Balance of Account 219 at Beginning of Current Year	(2,725,005)	6,150,330		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	2,127,497			
8	Current Quarter/Year to Date Changes in Fair Value	(713,442)	(6,150,330)		7,048,073
9	Total (lines 7 and 8)	1,414,055	(6,150,330)		7,048,073
10	Balance of Account 219 at End of Current Quarter/Year	(1,310,950)			7,048,073

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			887,774		
2			1,355,332		
3			1,182,219		
4			2,537,551	71,838,830	74,376,381
5			3,425,325		
6			3,425,325		
7			2,127,497		
8			184,301		
9			2,311,798	93,929,189	96,240,987
10			5,737,123		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	3,584,148,359	3,584,148,359
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,584,148,359	3,584,148,359
9	Leased to Others		
10	Held for Future Use	2,809,770	2,809,770
11	Construction Work in Progress	210,094,019	210,094,019
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	3,796,597,699	3,796,597,699
14	Accum Prov for Depr, Amort, & Depl	1,406,209,952	1,406,209,952
15	Net Utility Plant (13 less 14)	2,390,387,747	2,390,387,747
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,367,808,581	1,367,808,581
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	38,728,952	38,728,952
22	Total In Service (18 thru 21)	1,406,537,533	1,406,537,533
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	-327,581	-327,581
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,406,209,952	1,406,209,952

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	68,230	-6,070
3	(302) Franchises and Consents	19,396,545	2,315,082
4	(303) Miscellaneous Intangible Plant	50,277,981	2,322,444
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	69,742,756	4,631,456
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,370,319	
9	(311) Structures and Improvements	130,393,210	414,787
10	(312) Boiler Plant Equipment	493,554,906	16,388,465
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	122,505,166	2,513,151
13	(315) Accessory Electric Equipment	61,129,469	229,740
14	(316) Misc. Power Plant Equipment	12,943,071	355,278
15	(317) Asset Retirement Costs for Steam Production	3,633,334	203,234
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	825,529,475	20,104,655
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	13,924,472	8,598,979
28	(331) Structures and Improvements	130,044,154	3,733,010
29	(332) Reservoirs, Dams, and Waterways	243,998,118	622,923
30	(333) Water Wheels, Turbines, and Generators	185,687,563	1,794,280
31	(334) Accessory Electric Equipment	36,464,633	362,384
32	(335) Misc. Power PLant Equipment	14,816,368	774,079
33	(336) Roads, Railroads, and Bridges	6,950,430	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	631,885,738	15,885,655
36	D. Other Production Plant		
37	(340) Land and Land Rights	402,745	
38	(341) Structures and Improvements	5,338,800	-37,068
39	(342) Fuel Holders, Products, and Accessories	3,518,875	1,736
40	(343) Prime Movers	29,370,402	586,631
41	(344) Generators	60,940,312	15,945,150
42	(345) Accessory Electric Equipment	4,680,376	1,302
43	(346) Misc. Power Plant Equipment	1,341,403	43,842
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	105,592,913	16,541,593
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,563,008,126	52,531,903

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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
			62,160		2
			21,711,627		3
2,280,182			50,320,243		4
2,280,182			72,094,030		5
					6
					7
			1,370,319		8
271,303			130,536,694		9
4,485,105			505,458,266		10
					11
2,432,374			122,585,943		12
			61,359,209		13
211,835			13,086,514		14
			3,836,568		15
7,400,617			838,233,513		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			22,523,451		27
87,117			133,690,047		28
			244,621,041		29
40,935			187,440,908		30
21,242			36,805,775		31
			15,590,447		32
			6,950,430		33
					34
149,294			647,622,099		35
					36
			402,745		37
			5,301,732		38
			3,520,611		39
			29,957,033		40
15,200,000			61,685,462		41
			4,681,678		42
			1,385,245		43
					44
15,200,000			106,934,506		45
22,749,911			1,592,790,118		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	04/18/2007	End of 2006/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	24,807,969	3,944,894
49	(352) Structures and Improvements	33,134,805	3,720,354
50	(353) Station Equipment	235,849,248	11,585,786
51	(354) Towers and Fixtures	79,294,427	18,709,053
52	(355) Poles and Fixtures	92,201,304	-14,608,583
53	(356) Overhead Conductors and Devices	114,775,572	5,464,620
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)	580,381,676	28,816,124
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,148,221	-2,540,881
61	(361) Structures and Improvements	19,894,059	642,340
62	(362) Station Equipment	138,465,096	5,890,761
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	190,454,812	5,916,758
65	(365) Overhead Conductors and Devices	96,250,454	3,930,330
66	(366) Underground Conduit	41,610,525	2,310,695
67	(367) Underground Conductors and Devices	153,861,516	9,353,362
68	(368) Line Transformers	293,685,856	31,223,988
69	(369) Services	48,559,893	3,104,603
70	(370) Meters	50,388,983	5,162,843
71	(371) Installations on Customer Premises	2,560,296	113,016
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,000,780	130,097
74	(374) Asset Retirement Costs for Distribution Plant		370,187
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,046,880,491	65,608,099
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,603,829	156,936
87	(390) Structures and Improvements	61,374,695	3,295,717
88	(391) Office Furniture and Equipment	49,623,248	4,767,192
89	(392) Transportation Equipment	47,530,686	5,305,863
90	(393) Stores Equipment	973,761	18,765
91	(394) Tools, Shop and Garage Equipment	4,165,345	197,336
92	(395) Laboratory Equipment	9,260,297	791,787
93	(396) Power Operated Equipment	7,263,004	494,772
94	(397) Communication Equipment	26,090,518	3,347,912
95	(398) Miscellaneous Equipment	2,622,806	525,004
96	SUBTOTAL (Enter Total of lines 86 thru 95)	217,508,189	18,901,284
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	217,508,189	18,901,284
100	TOTAL (Accounts 101 and 106)	3,477,521,238	170,488,866
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,477,521,238	170,488,866

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			28,752,863		48
72,605			36,782,554		49
1,644,354			245,790,680		50
			98,003,480		51
310,268			77,282,453		52
223,382			120,016,810		53
					54
					55
			318,351		56
					57
2,250,609			606,947,191		58
					59
25			4,607,315		60
42,263			20,494,136		61
1,397,499			142,958,358		62
					63
1,669,990			194,701,580		64
1,261,783			98,919,001		65
288,371			43,632,849		66
866,016			162,348,862		67
6,147,819			318,762,025		68
392,086			51,272,410		69
2,929,694			52,622,132		70
39,279			2,634,033		71
					72
63,807			4,067,070		73
			370,187		74
15,098,632			1,097,389,958		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			8,760,765		86
279,334			64,391,078		87
17,040,309			37,350,131		88
1,785,800			51,050,749		89
10,165			982,361		90
140,394			4,222,287		91
290,949			9,761,135		92
450,791			7,306,985		93
1,241,602			28,196,828		94
243,067			2,904,743		95
21,482,411			214,927,062		96
					97
					98
21,482,411			214,927,062		99
63,861,745			3,584,148,359		100
					101
					102
					103
63,861,745			3,584,148,359		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Production			185,246
4	Transmission Stations			360,819
5	Transmission Lines			69,263
6	Distribution Stations			1,047,880
7				
8				
9				
10	Boise Operations Center	12/31/82		72,785
11	Boise Mechanical and Electrical Shop	12/31/01		47,000
12	Transmission Stations	12/31/81		178,094
13	Distribution Stations			80,306
14				
15				
16				
17				
18				
19	Column B if no date listed it is various			
20				
21	Other Property:			
22				
23				
24				
25				
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33				
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42				
43				
44				
45				
46				
47	Total			2,809,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	ROLLUP RELIC COST BROWNLEE	34,742,257
2	ROLLUP RELIC COST HELLS CANYON	23,814,989
3	LINE 722, CONSTRUCT NEW BORAH-	18,039,645
4	ROLLUP RELIC COST OXBOW	10,907,067
5	HELLS CANYON RELICENSING OUTSI	6,873,420
6	LINE 470 HRFT-STKY 138 KV	5,964,764
7	BRIDGER UNDISTRIBUTED WORK ORD	5,818,241
8	HELLS CANYON COMPLEX STURGILL	5,067,939
9	STKY 138KV SWITCHING STATION	4,066,505
10	VALMY 31818 U1 DCS UPGRADE PRO	3,949,832
11	HAPPY VALLEY SUBSTATION	3,002,336
12	DANSKIN UNIT #1 - 160 MW CT	2,864,384
13	LINE #470, 2ND 138KV LINE TO M	2,846,454
14	PAHSIMEROI HATCHERY EXPANSION	2,634,080
15	EMS/ADVANCED APPLICATION PROJE	2,591,861
16	CIAC LIABILITY RECLASS	2,187,429
17	VALMY UNDISTRIBUTED WORK ORDER	1,924,420
18	BUILD 138-KV LINE-CHUT TO HPVY	1,840,124
19	WQ ONGOING HELLS CANYON RELICE	1,668,628
20	CARTWRIGHT SUBSTATION	1,585,266
21	HCC RELICENSING FISH2004 FEASI	1,513,500
22	MIDPOINT - NEW 345KV, 175 MVAR	1,330,623
23	BORAH - NEW 345KV, 150 MVAR CA	1,312,994
24	VALMY 33397 #2 - DCS INSTALL	1,164,276
25	REL-HELLS CANYON COMPLEX FY200	1,120,690
26	342 COST CENTER DELIVERY CAPIT	1,070,726
27	BORAH - NEW 230 KV TERMINAL	1,060,702
28	REPLACE METALCLAD	1,028,023
29	POPULATION VIABILITY MODEL - W	943,616
30	VALMY 34534 U1 OVERFIRE AIR SY	939,348
31	COST CENTER 317 DELIVERY CAPIT	935,234
32	ROLLUP RELIC COST SWAN FALLS	820,228
33	LINE #426*RE-RATE LINE FOR BOR	808,088
34	BOMT-INCREASE 138/69KV CAPACIT	800,782
35	RIVER ENG.-HELLS CANYON CONTIN	795,509
36	CLOVERDALE USTICK DOUBLE CIRCU	790,821
37	418-CC DELIVERY CAPITAL OVERHE	757,169
38	OMS UPGRADE OPSCENTRICITY 1.7.	692,589
39	BOARDMAN UNDISTRIBUTED WORK OR	630,359
40	BKAT-MRDN CONVERT T202 TO 138K	625,141
41	VALMY 34086 U1 TURBINE OVERHAU	607,293
42	Line 722, ROW/Easements	606,015
43	TOTAL	210,094,019

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	HCC RELICENSING, FISH2004 ANAD	601,807
2	HCC RELICENSING, FISH2004 REDB	589,092
3	BANNER BANK FURNITURE	568,704
4	MAINT - LINE 951 MPSN-BORA 345	564,601
5	MIDPOINT 500 KV LINE RELAY REP	548,946
6	REPLACE NMPA METALCLAD SECT.1	531,576
7	BRIDGER 2007C004 REFURBISH U1	518,760
8	SWAN FALLS RELICENSING	516,267
9	HCC RELICENSING, FISH2004 INST	508,509
10	390 COST CENTER DELIVERY CAPIT	498,706
11	CONSTRUCTION ACCOUNTING CAPITA	493,835
12	IPCO/BOBN-041 REBUILD CENTERVI	487,739
13	#3 CONTROL AND EQUIPMENT UPGRA	475,469
14	LINE 441MODIFICATION FOR LINE4	469,421
15	IPCO-CSCD-011 REBUILD SOUTH AR	469,256
16	OP. HYDRO. - PHASE IV STREAMFL	464,296
17	NETWORK SWITCH REPLACEMENT	463,718
18	343 COST CENTER DELIVERY CAPIT	462,192
19	REL-HCC OREGON REAUTHORIZATION	460,866
20	LINE #438 CDAL-LCST IMPROVE RO	458,439
21	TRASH REMOVAL STRUCTURES	451,166
22	ORACLE RAC	445,794
23	RELOCATE ON POLELINE RD IN TWI	433,800
24	IPCO-CSCD-013 REBUILD FROM CAS	422,261
25	VALMY 34120 #1 PULVERIZER UPGR	417,293
26	NEW BOULDER 041 FEEDER	406,774
27	IPCO-CSCD-013-2006 BI	405,339
28	TRANSRELAY REPLACEMENT	400,897
29	HCC RELICENSING FISH2004 RESID	393,958
30	577 COST CENTER DELIVERY CAPIT	389,907
31	415-CC DELIVERY CAPITAL OVERHE	380,370
32	324-COST CENTER DELIVERY CAPIT	374,629
33	341 COST CENTER DELIVERY CAPIT	362,960
34	MPSN0603 REPLACE 308A BREAKER	362,643
35	336-COST CENTER DELIVERY CAPIT	362,427
36	2006 ADMINISTRATIVE SERVICES P	358,621
37	INSTALL 230KV PHASE SHIFTER AT	346,218
38	392 COST CENTER DELIVERY CAPIT	340,247
39	ROW FOR T404 - 138 KV TO CHERR	338,311
40	PAYROLL & IBNR ACCRUAL	335,991
41	BUILD NEW POLE LINE SUBSTATION	331,799
42	COST CENTER 316 DELIVERY CAPIT	328,308
43	TOTAL	210,094,019

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	04/18/2007	End of 2006/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	HAILEY TEAM CAP OH WORK ORDER	327,450
2	CALL CENTER LABOR HOURS FOR LI	325,011
3	REL - SWAN FALLS FY2004 CAPITA	319,166
4	LINE 470 STKY-MCAL 138KV	317,016
5	BOC ELEVATOR INSTALLATION	316,617
6	KPRT 230KV RELAY UPGRADE	315,318
7	IPCO-MCAL-041-REBUILD MAIN TRU	311,410
8	IPCO/HPVY-012 BUILD NEW FEEDER	304,467
9	335-COST CENTER DELIVERY CAPIT	302,351
10	LEGAL DEPT LABOR: HELLS CANYON	299,582
11	BDSS-PURCHASE SPARE 138-13KV,	297,416
12	MORA REPLACE T132 WITH NEW 44.	297,078
13	IPCO, MALPEGROVE RD. - FRANKLI	296,882
14	BARBER FLATS LAND SWAP-OXBOW	292,457
15	LEGAL DEPT. LABOR FOR RELICENS	291,030
16	KENYON - RELAY REPLACEMENT	285,342
17	IPCO/BOIS-014/2006 DOWNTOWN CA	285,283
18	PNUF-041 REBUILD 2 MILES OF 3	283,769
19	CAPITAL OVERHEADS FOR CADD & A	283,660
20	COM - REC BAKER CO SETTLEMENT	271,848
21	IPCO/HALY-015/F-18 TO IC-12 -	270,267
22	BNR4 - BANNER BANK COMMUNICATI	270,075
23	Delivery Overheads	269,832
24	DELIVERY CAPITAL OVERHEADS FOR	267,047
25	MCAL0503-CONVERT 69KV TO 138KV	264,461
26	585 COST CENTER DELIVERY CAPIT	263,973
27	NEW UNIT 6719 (CC 345) ADDL CR	262,708
28	458-COST CENTER DELIVERY CAPIT	260,734
29	575 COST CENTER DELIVERY CAPIT	258,144
30	JT MESSINA MEADOWS #1	256,308
31	ADAMSFAM TEAM CAP OH WORK ORDE	255,046
32	578 COST CENTER DELIVERY CAPIT	254,943
33	GOODING TEAM CAP OH WORK ORDER	251,690
34	VALMY 34087 REPL HVAC ROOF	250,332
35	VALMY 34084 #2 CLARIFIER FILTE	250,144
36	IPCO/HOLY-WESR 69KV - LINE 215	247,024
37	RELOCATE T412 STR. 59-65 (TERT	243,520
38	OPERATIONAL DATA STORE	241,342
39	LINE 438, RIGHT OF WAY, VICTOR	240,969
40	WQ SWAN FALLS RELICENSING-CAPI	237,956
41	SPVY0502-NEW 138-12.5KV SUBSTA	237,826
42	AUD UPGRADE PROJECT	236,242
43	TOTAL	210,094,019

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BOISE BENCH - KING 138 KV LINE	235,771
2	BRIDGER 2006C036 GREEN RIVER S	232,127
3	IPCO-RENFRO DAIRY-21351 ARENA	231,725
4	IPCO-CARTWRIGHT 012 BUILD NEW	229,714
5	420-CC DELIVERY CAPITAL OVERHE	228,908
6	100-COST CENTER DELIVERY CAPIT	226,991
7	327-COST CENTER DELIVERY CAPIT	224,138
8	JIM BRIDGER RAS-A AND RAS-B	218,075
9	2006 PC PURCHASES - CORPORATE	217,391
10	CDWL-INSTALL T132	215,810
11	SWAN FALLS RELICENSING FISH200	215,246
12	370 -COST CENTER DELIVERY CAPI	212,188
13	326-COST CENTER DELIVERY CAPIT	210,563
14	LINE 903 MAINTENANCE	210,144
15	TWINWEST TEAM CAP OH WORK ORDE	201,130
16	404 COST CENTER DELIVERY CAPIT	199,969
17	410-CC DELIVERY CAPITAL OVERHE	199,107
18	334-COST CENTER DELIVERY CAPIT	198,549
19	RIGHT OF WAY, TRANSMISSION LIN	193,128
20	ACHD/IPCO FRANKLIN ROAD REBUI	193,076
21	HELLS CANYON INFRASTRUCTURE	191,894
22	KING - REPLACE PCB SHUNT CAPAC	191,751
23	IPCO/GRVE-015/2006 DOWNTOWN CA	190,188
24	328-COST CENTER DELIVERY CAPIT	188,607
25	TOOL EXP TRANS TO CONST	188,428
26	BRIDGER 2007CCA3 U3 LOW NOX MO	186,700
27	455-COST CENTER DELIVERY CAPIT	186,327
28	NWMS0501 - CONVERT TO 138KV	185,452
29	REL - REC SWAN FALLS RELICENSI	184,461
30	IPCO-CARTWRIGHT 011 BUILD NEW	182,879
31	IPCO/ONTO19 REPLACE BAD UG PR	181,019
32	BRDY 230KV RELAY UPGRADE	181,003
33	UPGRADE CANEL GATE HOISTS	179,955
34	PRMA-041 REBUILD 3 MI TO 00 AC	179,545
35	BRIDGER 2007C036 INST ZOLOBOSS	176,690
36	PQ AG DSR LAB EQUIPMENT-ION	176,203
37	MINI CASSIA TEAM CAP OH WORK O	175,082
38	UPGRADE MV90 TO MV90XI	173,934
39	WESR-014 REPLACE 2 MI. ANNEAL	173,639
40	IDOT/IPCO CLOVERDALE R & HWY 2	173,284
41	REPLACE #5 VOLTAGE REGULATOR &	172,795
42	CHQ 9 EXECUTIVE AREA REMODEL	169,669
43	TOTAL	210,094,019

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	375 COST CENTER DELIVERY CAPIT	165,386
2	381 -COST CENTER DELIVERY CAPI	163,371
3	ZLOG - ADD NEW FEEDER 013	161,230
4	CHQ 2 BUILDINGS FURNITURE	159,795
5	IPCO/ELMR-041/VARIOUS DEVICES/	159,146
6	REL - REC HCC RELICENSING PROC	158,267
7	ENHANCED LAW ENFORCEMENT PER S	157,822
8	856 COST CENTER DELIVERY CAPIT	155,435
9	HCC WILDLIFE AND BOTANICAL	155,402
10	COC YARD PAVING	154,151
11	337-COST CENTER DELIVERY CAPIT	150,187
12	BANNER BANK	149,472
13	CITY OF KETCHUM-8TH ST,RELOCAT	148,675
14	BRIDGER 2006C149 CONTINUOUS BI	148,437
15	TERR: HCC RELICENSING	148,004
16	378 -COST CENTER DELIVERY CAPI	146,949
17	WESR-011 REPLACE 2.5 MILES W/	145,894
18	IPCO-ANTONIO AVELAR DAIRY-3835	145,745
19	LOWER MALAD FISH PASSAGE	145,701
20	FILER 46KV BREAKER	145,213
21	JIM BRIDGER SUBSTATION CAPITAL	145,040
22	VALMY 34083 #2 PULVERIZER UPGR	144,092
23	153 COST CENTER DELIVERY CAPIT	142,715
24	LSPO LICENSE ART 414 REC - RIV	142,382
25	COMPLIANCE- TRASH RAKE	141,935
26	BOC YARD IMPROVEMENT '06	141,493
27	#2 STATIC EXCITATION PURCHASE	140,671
28	BORA 230KV RELAY UPGRADE	140,401
29	IPCO/WESR-013/REBUILD 3.25 MIL	139,441
30	377 -COST CENTER DELIVERY CAPI	139,312
31	SERVER REPLACEMENT - OUT OF WA	138,504
32	WAN CISCO 7206 ROUTER REPLACEM	137,783
33	REPLACE UNIT #1 VOLTAGE REGULA	137,392
34	IPCO/BOIS-021/2006 DOWNTOWN CA	135,818
35	WHISPERING PINES SUBDV. - POWE	132,920
36	VULNERABLITY ASSESSMENT (ASLC	131,064
37	VALMY 34080 U1 BOTTOM ASH RECY	130,053
38	INVESTMENT RECOVERY ASPHALT PA	129,282
39	IPCO-VAN VLIET AND KENNINGTON	129,264
40	STAUFFER ESTATES-104 E 50 N/J	128,956
41	VALLEY CLUB WEST NINE SUBD-HAI	128,213
42	LOGISTIC LICENSE SERVER (LLS)	127,208
43	TOTAL	210,094,019

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	210-COST CENTER DELIVERY CAPIT	127,193
2	BRIDGER 2006C073 U4 REPL LOWER	125,444
3	TFEAST TEAM CAP OH WORK ORDER	124,737
4	JT CHARTER POINTE #10-URD SERV	124,692
5	TFSN-013 & 014 FEEDER GETAWAY	123,676
6	376 -COST CENTER DELIVERY CAPI	123,516
7	VALMY 31701 TURB LUBE OIL CENT	123,483
8	CHARTER POINTE #10-OVERHEAD UP	122,186
9	360 COST CENTER DELIVERY CAPIT	120,617
10	300 COST CENTER DELIVERY CAPIT	118,392
11	VALMY 32692 RAIL CAR DIST FEED	118,330
12	COWBOY TRAILER PARK- PHASE 3 O	118,326
13	COST CENTER 310 DELIVERY CAPIT	115,957
14	COST CENTER 310 DELIVERY CAPIT	115,783
15	RIVER ENG-SWAN FALLS RELICENSI	115,615
16	345 COST CENTER DELIVERY CAPIT	114,180
17	OXBOW FISH HATCHERY EXPANSION	113,612
18	382 -COST CENTER DELIVERY CAPI	112,127
19	PURCHASE STAR PROPERTY FOR NOR	111,457
20	DIDSON CAMERA	111,054
21	REPLACE UNIT #2 VOLTAGE REGULA	110,993
22	VALMY 34078 U1 COOLING TOWER T	110,447
23	HR COMPETENCY MANAGEMENT SYSTE	108,837
24	LINE #602, BLACKFOOT-GOSHEN 16	108,387
25	CIRRUS POINTE BY THE LAKE - PH	108,215
26	IPCO/NOVINIUM PILOT/BOBN-044-1	107,887
27	2006 PC PURCHASES - CAPITAL RE	107,529
28	IPCO/HPVY-013 BUILD NEW FEEDER	107,359
29	REC - BAKER COUNTY SETTLEMENT	106,389
30	BOBN-041 REBUILD .75 MILE AND	105,867
31	BOBN - REPLACE 138KV BREAKER O	105,143
32	HELLS CANYON CULTURAL	104,932
33	GSHN - REPLACE 171A	104,737
34	NEW UNIT 6729- 36' SERVICE BUC	103,225
35	BOARDMAN 22163 UPG DCS TO OVAT	103,064
36	2006 PC PURCHASES - SOUTHERN R	102,347
37	ELKHORN SPRINGS - SUN VALLEY/	101,096
38	OTHER MINOR WORK ORDERS	-2,549,383
39	CONSTRUCTION WIP CIAC CONTRA	1,206,080
40		
41		
42		
43	TOTAL	210,094,019

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	04/18/2007	End of 2006/Q4

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

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

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,333,025,502	1,333,025,502		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	90,803,410	90,803,410		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,738,380	2,738,380		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,561	108,561		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	93,650,351	93,650,351		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	61,581,537	61,581,537		
13	Cost of Removal	5,462,370	5,462,370		
14	Salvage (Credit)	11,108,059			
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	55,935,848	55,935,848		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,931,424			
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,367,808,581	1,367,808,581		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	420,177,111	420,177,111		
21	Nuclear Production				
22	Hydraulic Production-Conventional	240,328,423	240,328,423		
23	Hydraulic Production-Pumped Storage				
24	Other Production	2,366,353	2,366,353		
25	Transmission	210,074,912	210,074,912		
26	Distribution	411,582,068	411,582,068		
27	Regional Transmission and Market Operation	83,279,714	83,279,714		
28	General				
29	TOTAL (Enter Total of lines 20 thru 28)	1,367,808,581	1,367,808,581		

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report 2006/Q4

FOOTNOTE DATA

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

Relocation reimbursements, Up and down costs and damage and insurance claims $ 889,944.

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	$ (547,524)
Embedded removal in Accumulated Provision for Depreciation	3,478,950

	$2,931,424

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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			41,049,315
5				
6	Subtotal Idaho Energy Resources Company			43,512,409
7				
8				
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39				
40				
41				
42	Total Cost of Account 123.1 $ 2,463,093		TOTAL	43,512,409

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
8,401,787		49,451,102		4
				5
8,401,787		51,914,196		6
				7
				8
				9
				10
				11
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				41
8,401,787		51,914,196		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	04/18/2007	2006/Q4

FOOTNOTE DATA

Schedule Page: 224 Line No.: 6 Column: e

Instruction 3 says this number should equal Account 418.1 The difference between what is reported on page 224 Col E and 418.1 is $1,246,465. This amount has been reported in OCI, account 219

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	11,494,190	15,173,831	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)	11,238,406	12,191,263	
8	Transmission Plant (Estimated)	4,465,632	8,189,143	
9	Distribution Plant (Estimated)	12,235,598	15,527,757	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	766,156	854,043	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	28,705,792	36,762,206	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	1,745,428	2,316,011	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	41,945,410	54,252,048	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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						
25						
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28						
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46						
47						
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	04/18/2007	End of 2006/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	Asset Retirement Obligations - IPUC	8,363,188	2,842,868			11,206,056
2	Order #29414 - OPUC Order #04-585					
3						
4	LT & ST Mark to Market		2,979,296	244	1,516,659	1,462,637
5						
6	Tax Settlement - IPUC Order 29601	4,993,958	898,163	Footnote	5,892,121	
7	(Amort period 6/05 thru 5/06)					
8						
9	Regulatory Unfunded Accumulated Deferred Income Tax	346,116,633	6,235,763	282	8,762,742	343,589,654
10						
11	Power Cost Adjustment - IPUC order	33,561,270	314,475,471	Footnote	348,036,741	
12	#27660 (amort period 6/05 thru 5/07)					
13						
14	Idaho - Demand Side Management - IPUC order	14,591,747		401	3,242,604	11,349,143
15	#27660 (amort period 7/98 thru 6/10)					
16						
17	Excess Power Amortization - OR OPUC Order#06-070	8,411,118	682,926	401	2,423,697	6,670,347
18	(Capped at 10% per year until full amort)					
19						
20	Security Costs 2001-2002 - IPUC Order #28975	375,109		401	178,284	196,825
21	(amort period 1/03 - 12/07)					
22						
23	Security Costs 2003 - IPUC Order #28975	199,840	2,339	401	64,591	137,588
24	(amort period 1/04 - 12/08)					
25						
26	Professional Fees - IPUC order #29505	41,260	473	4073	20,487	21,246
27	(Amort period 1/03 thru 12/07)					
28						
29	IPUC Grid West Loans - IPUC order #30157		938,743	124	6,566	932,177
30	(amort period 1/07 - 12/11)					
31						
32	OPUC Grid West Loans - OPUC Order #06-483		56,332	131	325	56,007
33						
34	FERC Grid West Expense		302,117			302,117
35	FERC Docket # AC03-78-000					
36						
37	PCA Unbilled Amortization Reserve	(1,309,994)	3,550,579	Footnote	2,240,585	
38	(Reversed June 2006)					
39						
40	Excess Power Deferred - Oregon (see lines 18-19)	2,879,446	182,371	401	172,700	2,889,117
41	OPUC Order # 05-870					
42						
43	Minor items	17,615	33,969	401	17,615	33,969
44	TOTAL	418,241,190	333,181,410		372,575,717	378,846,883

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FOOTNOTE DATA

Schedule Page: 232 Line No.: 6 Column: d

254	$ 432,621
4073	5,458,679
4210	810
	$5,892,121

Schedule Page: 232 Line No.: 11 Column: d

232	$ 39,513,704
254	168,405,008
4073	7,165,784
431	438,756
401	80,977,504
1823	51,535,985
	$348,036,741

Schedule Page: 232 Line No.: 37 Column: d

232	$1,120,293
473	1,120,292
	$2,240,585

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	2,251,115		Footnote	2,251,115	
2						
3	Advance prepaid coal royalties	1,976,053		131	202,492	1,773,561
4						
5	Benefits plan - intangible asst	1,413,253		253	1,413,253	
6						
7	Security plan	28,585,485	1,958,997	Footnote	2,442,145	28,102,337
8						
9	American Falls bond refinance	278,918		401	14,552	264,366
10	(amort period 4/00 thru 7/26)					
11						
12	Prepaid Credit Facility	623,721	543,132	431	736,130	430,723
13						
14	Company owned Life Insurance	6,815,336	1,640,626	Footnote	2,503,251	5,952,711
15						
16	American Falls water rights	19,885,000		401	1,042,009	18,842,991
17	(amort period 1/06 thru 12/25					
18						
19	Milner bond guarantee	11,700,000				11,700,000
20						
21	Southwest intertie project -	6,333,391	41,183			6,374,574
22	right of way costs					
23						
24	CSPP receivable	1,016,847		143	364,185	652,662
25						
26	American Falls - bond refinance	919,983		401	47,999	871,984
27	(35 year amortization)					
28						
29	Transmission Deposit-PacifiCorp	295,375	783,475			1,078,850
30						
31	Prepaid Peoplesoft/Passport		162,005	401	66,419	95,586
32						
33	Adjustment to Unfunded Pension		49,993,497	190	3,812,252	46,181,245
34						
35	Transmission - General Studies		342,241	186	41	342,200
36						
37	06 Sweetwater Refi Costs		1,787,090	Footnote	108,842	1,678,248
38	(Amort period 2-2007 to 7-2026)					
39						
40	Minor Items & Job Orders (10)	-7,025	1,934,717	Various	1,880,796	46,896
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	82,087,452				124,388,934

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

4265	$1,949,916
186	96,798
186	204,401
	$2,251,115

Schedule Page: 233 Line No.: 7 Column: d

4262	$1,018,678
165	1,423,467
	$2,442,145

Schedule Page: 233 Line No.: 14 Column: d

4262	$1,089,572
131	1,302,548
419	5,604
186	105,427
	$2,503,151

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

1867	$ 21,411
131	87,431
	$108,842

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3	Emission Allowances	27,379,836	12,175,361
4	Advances for Construction	6,881,386	9,211,519
5	Other Electric (See footnote)	10,106,346	13,118,190
6			
7	Other (See footnote)	45,575,350	68,217,184
8	TOTAL Electric (Enter Total of lines 2 thru 7)	89,942,918	102,722,254
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric - See footnote	13,717,218	14,416,632
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	103,660,136	117,138,886

Notes

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

(Other):	Beginning Balance	Ending Balance
Post Retiree Benefits-VEBA	$ 1,893,065	$ 3,367,220
Rate Case Disallowance	3,316,285	3,228,546
Other Employee's Long Term Deferred Compensation	2,424,225	2,538,014
SFAS112 - Post Retirement Benefits	1,037,355	1,306,630
Non-VEBA Pension and Benefits	905,653	853,341
FAS 123R - Stock Based Compensation	-	585,567
Provision For Rate Refunds	-	479,888
American Falls Falling Water Contract	-	407,373
Linden Feeder Deposits	128,814	164,403
Restricted Stock Plan	215,673	160,625
City of Eagle	-	20,891
Delivery Accruals	-	5,692
Dark Fiber Contracts	101,285	-
Other Regulatory Liabilities	83,990	-
Total Other Electric	$ 10,106,346	$13,118,190

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

(Other):	Beginning Balance	Ending Balance
FASB 109 Accounting	$41,627,445	$41,825,257
FAS 158 - Pension	-	11,263,649
FAS 158 - Postretirement Plan	-	10,603,160
Minimum Pension Liability	3,947,905	4,525,117
Total Other	$45,575,350	$68,217,183

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

(Other Non Electric):	Beginning Balance	Ending Balance
Senior Management Security Plan	$10,851,325	$11,842,893
Micron-CIAC	2,477,838	2,239,495
Meridian Gold Contributions	219,016	196,904
Start-up and Organization Costs	75,447	75,447
Seattle City Light-CIAC	48,241	16,542
Loss on Pioneer Land Write-down	45,351	45,351
Total Non Electric	$13,717,218	$14,416,632

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
13				
14				
15				
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42				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
						8
						9
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						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	04/18/2007	End of 2006/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 - Miscellaneous paid-in Capital	
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39		
40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	5.30% Series Due 2035	60,000,000	408,411 D
11			
12			
13	6.60% Series due 2011	120,000,000	860,502
14			
15	4.25%Series due 2013	70,000,000	641,201
16			374,500 D
17			
18	4.75% Series due 2012	100,000,000	944,356
19			1,047,617 D
20			
21	6.00% Series due 2032	100,000,000	1,069,356
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	524,419
25			383,322 D
26			
27	5.50% Series due 2034	50,000,000	746,961 D
28			
29	Pollution control Revenue Bonds		
30	6.05% Series 96A due 2026		
31			
32	Series 96B due 2026		
33	TOTAL	987,045,000	12,866,803

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	3
						4
						5
12/1/00	12/01/07	12/01/00	12/01/07	80,000,000	5,904,000	6
						7
11/23/99	12/01/09	01/01/00	01/01/10	80,000,000	5,760,000	8
						9
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	10
						11
						12
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	13
						14
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	15
						16
						17
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
07/25/96	07/15/26	07/25/96	07/15/26		3,204,452	30
						31
07/25/96	07/15/26	07/25/96	07/15/26		672,283	32
				987,045,000	53,744,453	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	04/18/2007	End of 2006/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Series 96C due 2026		
3			
4	Port of Morrow Variable due 2027	4,360,000	188,545
5			
6	Humboldt Variable due 2024	49,800,000	1,697,856
7			
8	Sweetwater Variable due 2026 (IPC-E-06-14	116,300,000	820,043
9	OPUC UF 4227 WPSC 20005-29-ES-06)		471,252 D
10	Subtotal Account 221	955,460,000	12,866,803
11			
12	Account 224:		
13	Bond Guarantee - American Falls	19,885,000	
14			
15	REA Notes		
16			
17	Note Guarantee - Milner Dam	11,700,000	
18			
19	Subtotal Account 224	31,585,000	
20			
21	Account 222: Required Bonds		
22	Account 223: Advances for Associated Companies		
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	987,045,000	12,866,803

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
07/25/96	07/15/26	07/25/96	07/15/26	[redacted]	665,076	2
						3
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	166,187	4
						5
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	1,694,871	6
						7
10/3/06	7/15/26	10/3/06	7/15/2026	[redacted]	1,021,473	8
						9
				955,460,000	53,744,592	10
						11
						12
04/26/00	2/1/25			19,885,000		13
						14
					-139	15
						16
02/10/92				11,700,000		17
						18
				31,585,000	-139	19
						20
						21
						22
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						25
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						29
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						31
						32
				987,045,000	53,744,453	33

Schedule Page: 256 Line No.: 30 Column: h

See Footnote for page 257-1 Line 8.

Schedule Page: 256 Line No.: 32 Column: h

See footnote for page 257-1 Line 8.

Schedule Page: 256.1 Line No.: 2 Column: h

see footnote for page 257-1 Line 8.

Schedule Page: 256.1 Line No.: 8 Column: h

On October 3, 2006, IPC completed a tax-exempt bond financing in which Sweetwater County, Wyoming issued and sold $116.3 million aggregate principal amount of its Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006. The bonds will mature on July 15, 2026. The $116.3 million proceeds were loaned by Sweetwater County to IPC pursuant to a loan agreement, dated as of October 1, 2006, between Sweetwater County and IPC. On October 10, 2006, the proceeds of the new bonds, together with certain other moneys of IPC, were used to refund Sweetwater County's Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 1996A, Series 1996B and Series 1996C totaling $116.3 million. The regularly scheduled principal and interest payments on the Series 2006 bonds, and principal and interest payments on the bonds upon mandatory redemption on determination of taxability, are insured by a financial guaranty insurance policy issued by AMBAC Assurance Corporation. IPC and AMBAC have entered into an Insurance Agreement, dated as of October 3, 2006, pursuant to which IPC has agreed, among other things, to pay certain premiums to AMBAC and to reimburse AMBAC for any payments made under the policy. To secure its obligation to make principal and interest payments on the loan made to IPC, IPC issued and delivered to a trustee IPC's First Mortgage Bonds, Pollution Control Series C, in a principal amount equal to the amount of the new bonds

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	93,929,189
2		[redacted]
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	[redacted]
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10	See Footnote	[redacted]
11		
12		
13		
14	Income Recorded on Books Not Included in Return	[redacted]
15	See Footnote	[redacted]
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	[redacted]
20	See Footnote	[redacted]
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	158,674,773
28	Show Computation of Tax:	
29	Tentative Federal Tax @ 35%	55,536,171
30		
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Schedule Page: 261 Line No.: 5 Column: b

004003-CONSTRUCTION ADV-252	$ 6,657,523
004004-CIAC CLOSED TO PLANT	34,080,229
004005-AVOIDED COST INT CAP	3,983,765
004010-EMISSION ALLOWANCE-254.409-411	(38,891,098)
004013-CIAC AS TAXABLE INC IN ACCT 107	4,437,515
004017-JOINT USE FEE REC'D B4 INC BOOKED-253.050	(88,200)
004018-LINDEN FEEDER DEPOSITS-253.206	91,034
004019-IDWR STREAMFLOW GUAGING CONTRACT-242.312	29,366
004020-ENGINEERING FEES CLOSED TO PLANT	1,497,908
004021-ENGINEERING FEES IN ACCT 107	100,750
004022-CITY OF EAGLE-ACCT 253.209	53,437
004501-ROYALTY INCOME BTL	100,000
004506-CIAC-MERIDIAN GOLD	(56,560)
004507-CIAC-MICRON-DRAM	(608,652)
004512-CIAC-SEATTLE CITY LIGHT	(81,312)
Total	$ 11,305,705

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

Total Federal and State taxes deducted on books	$ 44,378,930
005001-BAD DEBT EXPENSE	134,835
005008-GAIN/LOSS ON REACQUIRED DEBT-DEFERRED	549,856
005010-SFAS 112-POST-EMPLY BEN 182/253	688,770
005014-OVERACCRUED VACATION-ACCT 242	698,941
005017-INJURIES & DAMAGES	(920,977)
005019-DIRECTORS FEES DEF	242,996
005022-CAPITALIZED OVERHEADS	(12,000,000)
005023-PENSION ACCR TO 926200	5,433,988
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	300,000
005025-MILNER FALLING WATER - REV ACCRL	264,100
005027-AMORTIZATION OF ACCOUNT 114	(22,723)
005028-OREGON OPER PROPERTY TAX ADJ	(18,269)
005033-NONVEBA PEN&BEN-Acct 228	(133,809)
005035-PCA EXPENSE DEFERRAL	21,356,345
005043-AMERICAN FALLS FALLING WATER CONTRACT	1,042,009
005044-RESTRICTED STOCK PLAN-COMP	(141,749)
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	291,057
005048-BONUS DEFERRAL-232	(183,380)
005050-186-BAD DEBT RESERVE-FINANCING PRGMS	(29,337)
005051-PUC ORDER 29505 - PROFESSIONAL FEES	20,013
005052-AMORTIZATION OF ACCOUNT 181	136,345
005053-FAS 123R-STOCK BASED COMPENSATION	1,497,805
005054-IPUC GRID WEST LOANS-ACCT 182	(932,177)
005055-OPUC GRID WEST LOANS-ACCT 183	(56,007)
005056-FERC GRID WEST EXP-ACCT 182	(302,117)
005501-SEC PLAN-NET INS COSTS	(349,485)
005502-128-SMSP-MRKT CHG OF RABBI INVSTMNTS	-
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST	(104,905)
005504-NONDEDUCTIBLE POLITICAL EXP-426.4	300,000
005505-SEC PLAN-BENEFIT ACCR	2,536,305
005510-FINES AND PENALTIES	2,307
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS	100,000

005531-RATE CASE DISALLOWANCES-REVERSE AMORT	(296,299)
005532-DELIVERY ACCRUALS-253.550	(209,316)
005536-VEBA INCOME TAXES	12,232
Total	$ 64,286,284

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

007002-GAIN ON SALE OF BOC	$ 29,306
007009-PROVISION FOR RATE REFUNDS-ACCT 229	(1,227,492)
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	9,648,252
007502-ALLOWANCE FOR OFUDC	6,092,152
007503-ALLOWANCE FOR BFUDC	4,026,460
007504-RECLASS TAX EXEMPT INTEREST - FED ONLY	511,322
007514-COLI-INSURANCE PROCEEDS	1,561,550
Total	$ 20,641,550

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$ (2,870,698)
008009-DEPR FOR TAX GT OR LT BOOK	(12,563,248)
008016-VEBA-POST RETIRE BENEFITS-TRUST-MEDICARE PART D	794,000
008020-CONSERVATION PROGRAMS	(3,242,604)
008022-263A 481(a)-FACTS & CIRCUMSTANCES (87-04)	(13,673,245)
008025-MANUFACTURING DEDUCTION-ORE NOT ALLWD	2,219,707
008027-NEVADA OPERATING PROPERTY TAX ADJ	(7,365)
008034-REMOVAL COSTS	5,462,628
008035-REPAIR ALLOWANCE	7,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS	(1,731,100)
008039-ST TAX-NOT DEDUCTED ON PRIOR RETURN	(503,266)
008041-AM FALLS - UNAMORTIZED DEBT EXP	(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT	1,278,169
008045-ST TAX-AUDIT STTLMNTS PAID THIS YR	-
008062-FERC ORDER 2000 COSTS	(2,251,115)
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY	2,700,000
008074-INCREMENTAL SECURITY COSTS DEDUCTED	(240,536)
008077-PP INS & OTR EXP (1 YR OR LESS)-165	1,390,589
008501-COLI-TAX ADJ FROM BOOKS	(804,951)
008504-OREGON NONOP PROPERTY TAX ADJUST	(20)
008508-DEPR ADJ - NONOP - OTHER PROPERTY - NEW	4,125
0NI0016-DIV PAID DED PUB UTIL	300,000
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	6,991,785
Total	$ (9,795,144)

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	50,890,071		47,417,184	74,035,895	
3	Social Security - (FOAB)	351,904		9,898,117	9,868,447	
4	Unemployment	36,235		117,591	114,279	
5	Subtotal Federal	51,278,210		57,432,892	84,018,621	
6						
7	State of Idaho:					
8	Property	6,094,309		10,366,708	11,716,731	
9	Income	11,269,333		4,815,467	8,538,469	
10	KWH	96,161		2,058,404	2,061,573	
11	Unemployment	21,395		262,673	265,469	
12	Regulatory Commission			1,682,342	1,682,342	
13	Business License - Sho Ban		150	150	150	
14	Subtotal Idaho	17,481,198	150	19,185,744	24,264,734	
15						
16	State of Oregon					
17	Property		986,772	1,992,276	2,010,525	
18	Income	1,168,761		321,268	561,483	
19	Regulatory Commission			102,377	102,377	
20	Unemployment	856		18,305	17,688	
21	Franchise	122,634		503,988	500,221	
22	Subtotal Oregon	1,292,251	986,772	2,938,214	3,192,294	
23						
24	State of Montana:					
25	Property	46,694		99,363	96,418	
26	Subtotal Montana	46,694		99,363	96,418	
27						
28	State of Nevada:					
29	Property		419,320	857,398	850,033	
30	Business Tax			100	100	
31	Subtotal Nevada		419,320	857,498	850,133	
32						
33	State of Wyoming					
34	Corporate License			3,144	3,144	
35	Property	496,473		1,028,150	1,010,548	
36	Subtotal Wyoming	496,473		1,031,294	1,013,692	
37						
38	Other States Income	1,588,880		-32,623	45,399	
39	Payroll Adjustment			-10,293,932		
40						
41	TOTAL	72,183,706	1,406,242	71,218,450	113,481,291	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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
24,271,360		52,572,378			-5,155,194	2
381,573		9,898,117				3
39,547		117,591				4
24,692,480		62,588,086			-5,155,194	5
						6
						7
4,744,361	75	10,334,859			-31,830	8
7,546,331		4,899,888			-20,742	9
92,992		2,058,404				10
18,600		262,673				11
		1,682,342				12
	150	150				13
12,402,284	225	19,238,316			-52,572	14
						15
						16
	1,005,022	1,988,384			3,892	17
928,546		325,560			-4,292	18
		102,377				19
1,474		18,305				20
126,401		503,988				21
1,056,421	1,005,022	2,938,614			-400	22
						23
						24
49,639		99,363				25
49,639		99,363				26
						27
						28
	411,955	857,398				29
		100				30
	411,955	857,498				31
						32
						33
		3,144				34
514,075		1,028,150				35
514,075		1,031,294				36
						37
1,510,858		-31,191			-1,432	38
		-10,293,932				39
						40
40,225,757	1,417,202	76,428,048			-5,209,598	41

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/18/2007	2006/Q4

FOOTNOTE DATA

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

Account 409.2	$(4,206,659)
234	(948,535)
Total	$(5,155,194)

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

Account 408.2

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

Account 409.2	$ 86,225
234	(170,646)
Total	$ (84,421)

Schedule Page: 262 Line No.: 17 Column: l

Account 408.2

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

Account 409.2	$ 4,385
234	(8,677)
Total	$ (4,292)

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

Account 409.2	$ 1,461
234	(2,893)
Total	$ (1,432)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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%	1,385,680				152,715	
4	7%						
5	10%	34,256,810				1,906,732	
6	11%	1,401,677				27,085	
7	Other - State	31,742,106	411	3,840,143	411	1,426,742	
8	TOTAL	68,786,273		3,840,143		3,513,274	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	31,742,106	411	3,840,143	411	1,426,742	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
1,232,965			3
			4
32,350,078			5
1,374,592			6
34,155,507			7
69,113,142			8
			9
			10
			11
34,155,507			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
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			46
			47
			48

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Joint Pole Use	465,668	Footnote	1,647,889	1,182,221	
2						
3	Bureau of Land Mngt Rents/ROW	5,011,800	Footnote	1,770,740	1,888,417	5,129,477
4						
5	Point to Point Transmission Study	1,129,930	Footnote	1,350,875	730,875	509,930
6						
7	FTV	4,866,666	Footnote	800,639	1,000,639	5,066,666
8						
9	Linden Feeder	329,489	107	11,499	102,533	420,523
10						
11	SWIP Deposit	600,000			400,000	1,000,000
12						
13	IDACOMM Dark Fiber	8,000	454	8,000		
14						
15	City of Eagle				53,437	53,437
16						
17	Sho Ban Trans ROW	2,428,333	242	4,211,666	2,098,333	315,000
18						
19	Delivery Accruals	71,673	Footnote	112,223	59,858	19,308
20						
21	Construction Work In Progress	2,569,896	107	13,435,240	10,865,344	
22						
23	Customer Level Pay	1,135,105	142	646,234	1,540,099	2,028,970
24						
25	US Airforce Photovoltaic Generator	203,957			40,190	244,147
26						
27	Security Plan	27,756,298	Footnote	32,645,347	4,889,050	1
28						
29	Milner Falling Water	3,456,957			264,100	3,721,057
30						
31	Postretirement Benefits	2,653,421			688,770	3,342,191
32						
33	Benefit Plan - Minimum Liability	11,511,488	228	11,511,488		
34						
35	Directors Deferred Compensation	3,473,798	232	327,488	570,483	3,716,793
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	67,672,479		68,479,328	26,374,349	25,567,500

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

	454	$ (399,340)
	143	(508,720)
	242	(739,829)
Total		$(1,647,889)

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

	107	$ (131,296)
	232	(1,206,458)
	253	(432,403)
	107	(583)
Total		$(1,770,740)

Schedule Page: 269 Line No.: 5 Column: c

	232	$(1,106,500)
	242	(244,375)
Total		$(1,350,875)

Schedule Page: 269 Line No.: 7 Column: c

	454	$(400,639)
	242	(400,000)
Total		$(800,639)

Schedule Page: 269 Line No.: 19 Column: c

	232	$ (96,769)
	107	(14,676)
	401	(778)
Total		$(112,223)

Schedule Page: 269 Line No.: 27 Column: c

	232	$ (1,949,291)
	241	(403,452)
	228	(30,292,604)
Total		$(32,645,347)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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) 04/18/2007	Year/Period of Report End of 2006/Q4

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	239,876,397	1,580,695	11,339,130
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	239,876,397	1,580,695	11,339,130
6	Non-Operating Property	267,308		
7	Other - FASB 109	346,116,633		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	586,260,338	1,580,695	11,339,130
10	Classification of TOTAL			
11	Federal Income Tax	495,099,794	1,563,016	11,339,130
12	State Income Tax	91,160,544	17,679	
13	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) 04/18/2007	Year/Period of Report End of 2006/Q4

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.
[redacted]							1
						230,117,962	2
							3
							4
						230,117,962	5
1,613	25,478					243,443	6
		182	5,035,829	182	2,508,849	343,589,653	7
							8
1,613	25,478		5,035,829		2,508,849	573,951,058	9
[redacted]							10
1,353	21,372		2,711,164		2,508,849	485,101,346	11
260	4,106		2,324,665			88,849,712	12
							13

NOTES (Continued)

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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) 04/18/2007	Year/Period of Report 2006/Q4

FOOTNOTE DATA

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

		2,006	Changes during Year			Adjustments Debits			Adjustments Credits		2006
Line No.	Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. CR g	Amt h	Acct. dr i	Amt j	Ending Balance k
Line 2:	Accelerated Depreciation	226,279,313	3,907,961	10,732,993							219,454,280
	Intangible Asset-Labor Ded	11,079,880	247,856								11,327,736
	FERC Jurisdictional	7,818,502									7,818,502
	N. Valmy	810,266		76,500							733,766
	Bridger	324,857		102,400							222,457
	CIAC Taxable Inc-Acct 253.575	85,531		85,531							0
	Repair Allowance	53,185		53,185							0
	Engineering Fees in Acct 107	0	(35,263)								(35,263)
	Misc Software Develop Costs	(844,491)	(1,721,045)								(2,565,535)
	Taxable CIAC in CWIP Bal.	(5,730,646)	(818,815)	288,522							(6,837,982)
	TOTAL Line 2	239,876,397	1,580,695	11,339,131	-	-	-	-	-	-	230,117,961

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	22,480,999	-5,482,489	3,500,145
4				
5				
6				
7				
8	Other -- See Note	949,275		
9	TOTAL Electric (Total of lines 3 thru 8)	23,430,274	-5,482,489	3,500,145
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	350,465		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	23,780,739	-5,482,489	3,500,145
20	Classification of TOTAL			
21	Federal Income Tax	19,863,985	-4,599,008	2,877,783
22	State Income Tax	3,916,754	-883,481	622,362
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
							2
						13,498,365	3
							4
							5
							6
							7
			107,597		18,054,557	18,896,235	8
			107,597		18,054,557	32,394,600	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
-5,492	-7,359					352,332	18
-5,492	-7,359		107,597		18,054,557	32,746,932	19
[redacted]							20
-4,606	-6,165		90,260		15,145,139	27,443,632	21
-886	-1,194		17,337		2,909,418	5,303,300	22
							23

NOTES (Continued)

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/18/2007	2006/Q4

FOOTNOTE DATA

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

		2006	Changes during Year				Adjustments Debits		Adjustments Credits		2006
Line No.	Other Electric (283) Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Line 3:	PCA Expense Deferral	12,995,966	(7,764,810)	584,453							4,646,703
	Conservation Programs	5,704,643	1	1,267,696							4,436,949
	Oregon Excess Power Costs	4,414,046	254,390	931,163							3,737,272
	IPUC Grid West Loans	-	364,435								364,435
	Loss on Reacquired Debt	(1,229,581)	1,641,599	214,966							197,052
	Incremental Security Costs	224,776	0	94,038							130,739
	FERC Grid West Expense	-	118,113								118,113
	OPUC Grid West Loans	-	21,896								21,896
	Professional Fees - IPUC Order 29505	16,131		7,824							8,306
	FERC Order 2000 Costs	880,073	(118,113)	761,961							-
	FERC Order 144A	(525,056)		(361,956)							(163,100)
	TOTAL Line 3	22,480,999	(5,482,489)	3,500,146	-	-		-		-	13,498,365

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

		b	c	d	e	f	g	h	i	j	k
Line 8:	FAS 158 - Pension	-							190	11,263,649	11,263,649
	FAS 158 - Postretirement Plan	-							186/190	6,790,909	6,790,908
	Unrealized gains on Market Securities	949,275					219	107,598	219		841,677
	TOTAL Line 8	949,275	-	-	-	-		107,598		18,054,558	18,896,235

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

Page 274 – Accumulated Deferred Income Taxes - Other Property (Account 282)

		2006	Changes during Year				Adjustments Debits		Adjustments Credits		2006
Line No.	Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Line 18:	Advance Coal Royalties	326,666			0	39,095					287,571
	Oregon Non-Op Prop Tax Adj	808			-	51					757
	Unrealized Gain/Loss From Rabbit Trust	22,991			(5,492)	(46,505)					64,004
	TOTAL Line 18	350,465	-	-	(5,492)	(7,359)		-		-	352,332

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term	244,432	175	368,821	124,389	
2						
3	Demand Side Management Rider 29026	6,146,841	Footnote	11,228,977	11,016,598	5,934,462
4						
5	Demand Side Management Rider OR	214,834	Footnote	302,997	481,894	393,731
6						
7	Other Deferred Credit - PCA		1823	162,793,803	150,942,101	-11,851,702
8						
9	BPA Credit-Residential - Idaho	841,354	Footnote	17,805,810	18,075,114	1,110,658
10						
11	BPA Credit-Residential - Oregon		Footnote	682,431	745,799	63,368
12						
13	BPA Credit-Farm - Idaho	534,405	Footnote	1,923,016	2,312,360	923,749
14						
15	BPA Credit-Farm - Oregon	16,978	142	75,533	85,013	26,458
16						
17	BPA Credit - Conservation	173,666	Footnote	992,418	818,752	
18						
19	IPUC Order 29600	4,020,833	182	4,020,833		
20						
21	Emission Sales Pre Tax	69,979,291	Footnote	80,727,249	10,747,958	
22						
23	Emission Sales Interest - Idaho	45,691	Footnote	727,033	27,706,355	27,025,013
24						
25	Emission Sales Interest - Oregon	9,129			4,108,871	4,118,000
26						
27	Boise Operation Center	29,306	Footnote	29,306		
28						
29	Unfunded Accumulated Deferred Income Tax	41,627,446	282	65,811	263,622	41,825,257
30						
31	Asset Retirement Oblication - Removal Cost	152,683,099			3,478,949	156,162,048
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	276,567,305		281,744,038	230,907,775	225,731,042

Schedule Page: 278 Line No.: 3 Column: c

107	$	120
131		23
142		1,401,723
154		1,099,031
165		6,298
184		8,907
232		8,344,746
242		127,700
254		203,867
401		36,564
	$	11,228,977

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

142	$	53,440
154		3,878
165		607
184		469
232		230,143
242		5,820
254		6,726
401		1,880
421		34
	$	302,997

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

131	$	3,310
142		17,402,446
143		400,054
	$	17,805,810

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

131	$	87
142		681,122
143		1,223
	$	682,431

Schedule Page: 278 Line No.: 13 Column: c

131	$	3
142		1,923,014
	$	1,923,016

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

143	$	14,454
154		21,791
232		912,686
242		31,348
254		9,009
401		3,112
431		18
	$	992,418

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

182	$ 80,725,147
232	2,102
	$ 80,727,249

Schedule Page: 278 Line No.: 23 Column: c

182	$ 617,203
431	109,831
	$ 727,033

Schedule Page: 278 Line No.: 27 Column: c

163	$ 293
401	19,928
402	9,085
	$ 29,306

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

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	299,593,554	299,487,636
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	231,430,314	247,103,087
5	Large (or Ind.) (See Instr. 4)	102,958,015	118,259,189
6	(444) Public Street and Highway Lighting	2,392,957	2,419,886
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	636,374,840	667,269,798
11	(447) Sales for Resale	260,717,491	142,794,426
12	TOTAL Sales of Electricity	897,092,331	810,064,224
13	(Less) (449.1) Provision for Rate Refunds	1,211,251	-400,102
14	TOTAL Revenues Net of Prov. for Refunds	895,881,080	810,464,326
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	5,424,893	5,475,745
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,858,178	17,912,109
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	12,454,460	15,223,771
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	34,737,531	38,611,625
27	TOTAL Electric Operating Revenues	930,618,611	849,075,951

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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
5,067,767	4,760,275	387,707	373,602	2
				3
5,368,218	5,077,227	76,343	74,448	4
3,475,157	3,422,616	130	129	5
28,172	28,694	789	640	6
				7
				8
				9
13,939,314	13,288,812	464,969	448,819	10
5,820,823	2,773,852			11
19,760,137	16,062,664	464,969	448,819	12
				13
19,760,137	16,062,664	464,969	448,819	14

Line 12, column (b) includes $ -6,215,836 of unbilled revenues.

Line 12, column (d) includes 28,191 MWH relating to unbilled revenues

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,084,646	303,353,321	387,552	13,120	0.0597
3	04 - Residential - EW	1,097	64,982	71	15,451	0.0592
4	05 - Residential - TOD	1,344	80,291	84	16,000	0.0597
5	15 - Dusk to dawn lighting	2,458	440,548			0.1792
6	Unbilled Revenues	-21,778	-4,345,588			0.1995
7	Total 440	5,067,767	299,593,554	387,707	13,071	0.0591
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	267,332	19,557,378	34,577	7,731	0.0732
11	09 - General service	362,545	13,096,260	132	2,746,553	0.0361
12	09 - General service	3,102,085	128,573,864	22,425	138,332	0.0414
13	09 - General service	2,844	108,463	2	1,422,000	0.0381
14	15 - Dusk to Dawn Light	3,867	614,063			0.1588
15	19 - Uniform rate contracts	2,126,165	67,982,257	121	17,571,612	0.0320
16	19 - Uniform rate contracts	8,439	301,301	1	8,439,000	0.0357
17	19 - Uniform rate contracts	189,629	5,323,486	5	37,925,800	0.0281
18	24 - Irrigation Pumping	1,617,905	70,659,508	17,965	90,059	0.0437
19	25 - Irrigation Pumping -Time of	17,556	782,417	113	155,363	0.0446
20	40 - General service	14,045	775,900	1,129	12,440	0.0552
21	Commercial & Industrial & Unbill	1,130,963	26,613,432	3	376,987,667	0.0235
22	Total 442	8,843,375	334,388,329	76,473	115,640	0.0378
23						
24	444 - Public Street Lighting:					
25	40 - General service	1,923	105,556	510	3,771	0.0549
26	41 - Street lighting	20,586	2,088,985	146	141,000	0.1015
27	42 - Traffic control lighting	5,663	198,416	133	42,579	0.0350
28	Total 444	28,172	2,392,957	789	35,706	0.0849
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,911,123	642,590,676	464,969	29,918	0.0462
42	Total Unbilled Rev.(See Instr. 6)	28,191	-6,215,836	0	0	-0.2205
43	TOTAL	13,939,314	636,374,840	464,969	29,979	0.0457

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Raft River Rural Electric	RQ	V6-44	9.573	9.573	8.675
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
4	City of Weiser	RQ	V6-53	9.055	9.051	8.830
5						
6						
7						
8	American Electric Power Service Cor	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.	OS	WSPP	n/a	n/a	n/a
11	Arizona Public Service Co.	OS	WSPP	n/a	n/a	n/a
12	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
13	Avista Corp. - WWP Div.	OS	WSPP	n/a	n/a	n/a
14	Avista Corp. - WWP Div.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
58,628	256,028	1,211,054	[redacted]	1,470,832	1
			[redacted]	93,593	2
17		[redacted]		374	3
50,325	527,668	963,714	[redacted]	1,920,472	4
					5
					6
					7
40,000		2,197,130		2,197,130	8
185		[redacted]		9,375	9
2,000		[redacted]		80,000	10
			[redacted]	127,344	11
686,194		27,519,003		27,519,003	12
10,441		[redacted]		431,890	13
6,115		274,985		274,985	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Avista Energy, Inc.	OS	WSPP	n/a	n/a	n/a
2	Avista Energy, Inc.	OS	WSPP	n/a	n/a	n/a
3	Avista Energy, Inc.	OS	WSPP	n/a	n/a	n/a
4	Avista Energy, Inc.	SF	WSPP	n/a	n/a	n/a
5	Barclays Bank PLC	SF	WSPP	n/a	n/a	n/a
6	Benton County PUD	OS	WSPP	n/a	n/a	n/a
7	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
8	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
9	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
10	Bonneville Power Administration	OS	WSPP	n/a	n/a	n/a
11	Bonneville Power Administration	OS	WSPP	n/a	n/a	n/a
12	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
13	BP Energy Company	OS	WSPP	n/a	n/a	n/a
14	BP Energy Company	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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.
13,790		599,223		599,223	1
95,490		3,929,239		3,929,239	2
			20,003	20,003	3
330,709		13,975,504		13,975,504	4
3,600		204,900		204,900	5
317		13,675		13,675	6
			1,537	1,537	7
28,981		908,425		908,425	8
51,871		1,498,438		1,498,438	9
60		2,400		2,400	10
36,933		1,525,490		1,525,490	11
58,883		2,649,005		2,649,005	12
7,000		330,000		330,000	13
491		18,785		18,785	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Energy Company	SF	WSPP	n/a	n/a	n/a
2	Burbank, City of	OS	WSPP	n/a	n/a	n/a
3	Burbank, City of	SF	WSPP	n/a	n/a	n/a
4	Calpine Energy Services, L.P.	OS	WSPP	n/a	n/a	n/a
5	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
6	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
7	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
8	Chelan Co PUD	OS	WSPP	n/a	n/a	n/a
9	Chelan Co PUD	SF	WSPP	n/a	n/a	n/a
10	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
11	Clatskanie PUD	OS	WSPP	n/a	n/a	n/a
12	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
13	Conoco Phillips Company	OS	WSPP	n/a	n/a	n/a
14	Conoco Phillips Company	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
344,935		18,333,250		18,333,250	1
1,098		45,356		45,356	2
7,681		374,300		374,300	3
645		19,662		19,662	4
			527,869	527,869	5
96		4,477		4,477	6
122,677		4,101,800		4,101,800	7
1,222		54,725		54,725	8
1,200		44,800		44,800	9
45,200		2,659,850		2,659,850	10
855		35,605		35,605	11
1,600		78,100		78,100	12
2,019		100,837		100,837	13
600		17,800		17,800	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	OS	WSPP	n/a	n/a	n/a
2	Constellation Energy Commodities Gr	SF	WSPP	n/a	n/a	n/a
3	Coral Power, LLC	OS	WSPP	n/a	n/a	n/a
4	Coral Power, LLC	SF	WSPP	n/a	n/a	n/a
5	DB Energy Trading, LLC	OS	WSPP	n/a	n/a	n/a
6	DB Energy Trading, LLC	SF	WSPP	n/a	n/a	n/a
7	Douglas County PUD	OS	WSPP	n/a	n/a	n/a
8	El Paso Electric Company	OS	WSPP	n/a	n/a	n/a
9	Eugene Water & Electric Board	OS	WSPP	n/a	n/a	n/a
10	Eugene Water & Electric Board	SF	WSPP	n/a	n/a	n/a
11	Franklin County P.U.D.	OS	WSPP	n/a	n/a	n/a
12	Grant County P.U.D.	OS	V6-58	n/a	n/a	n/a
13	Grant County P.U.D.	OS	WSPP	n/a	n/a	n/a
14	Grant County P.U.D.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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.
285		[redacted]		14,550	1
47,377		2,767,306		2,767,306	2
362		[redacted]		18,625	3
89,834		4,861,123		4,861,123	4
400		[redacted]		21,500	5
14,600		845,510		845,510	6
3		[redacted]			7
100		[redacted]		6,000	8
2,564		[redacted]		104,090	9
3,625		153,327		153,327	10
105		[redacted]		4,815	11
			[redacted]	240	12
1,975		[redacted]		81,775	13
1,800		78,100		78,100	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grays Harbor PUD	OS	WSPP	n/a	n/a	n/a
2	J. Aron & Company	SF	WSPP	n/a	n/a	n/a
3	Los Angeles Department of Water and	SF	WSPP	n/a	n/a	n/a
4	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
5	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
6	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
7	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
8	Northern California Power Agency	OS	WSPP	n/a	n/a	n/a
9	Northern California Power Agency	OS	WSPP	n/a	n/a	n/a
10	Northern California Power Agency	SF	WSPP	n/a	n/a	n/a
11	NorthWestern Energy	IF	147	n/a	n/a	n/a
12	NorthWestern Energy	IF	147	n/a	n/a	n/a
13	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
14	Pacific Northwest Generating Cooper	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
20		[redacted]		1,050	1
2,000		105,050		105,050	2
800		38,400		38,400	3
19,200		[redacted]		1,046,400	4
			[redacted]	835,968	5
2,883		[redacted]		132,474	6
711,372		32,271,704		32,271,704	7
6,829		[redacted]		286,695	8
16		[redacted]		1,120	9
2,554		103,767		103,767	10
57,848		2,508,584		2,508,584	11
			[redacted]	3,545,475	12
268		[redacted]		13,730	13
30		[redacted]		1,890	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Pacific Northwest Generating Cooper	SF	WSPP	n/a	n/a	n/a
2	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
3	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
4	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
5	PacifiCorp Inc.	SF	V6-13	n/a	n/a	n/a
6	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
7	Pinnacle West Capital Corporation	SF	WSPP	n/a	n/a	n/a
8	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
9	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
10	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
11	Portland General Electric Company	SF	V6-54	n/a	n/a	n/a
12	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
13	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
14	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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		12,030		12,030	1
			519,057	519,057	2
18,761		[illegible]		778,830	3
219,064		9,657,371		9,657,371	4
			[illegible]	1,250	5
215		9,297		9,297	6
1,400		81,600		81,600	7
			[illegible]	3,010	8
54,364		[illegible]		2,098,409	9
148,280		8,120,564		8,120,564	10
			[illegible]	1,850	11
			[illegible]	589,024	12
91,905		3,097,230		3,097,230	13
677,132		25,726,304		25,726,304	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PPL Montana, LLC	OS	WSPP	n/a	n/a	n/a
2	PPL Montana, LLC	OS	WSPP	n/a	n/a	n/a
3	PPL Montana, LLC	SF	WSPP	n/a	n/a	n/a
4	PPL Montana, LLC	SF	V6-57	n/a	n/a	n/a
5	PPM Energy, Inc.	OS	WSPP	n/a	n/a	n/a
6	PPM Energy, Inc.	OS	WSPP	n/a	n/a	n/a
7	PPM Energy, Inc.	SF	WSPP	n/a	n/a	n/a
8	Public Service Co. of Colorado	OS	WSPP	n/a	n/a	n/a
9	Public Service Co. of Colorado	SF	WSPP	n/a	n/a	n/a
10	Public Service Company of New Mexic	OS	WSPP	n/a	n/a	n/a
11	Public Service Company of New Mexic	SF	WSPP	n/a	n/a	n/a
12	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
13	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
14	Rainbow Energy Marketing Corporatio	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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 ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			[redacted]	19,457	1
9,425		[redacted]		350,671	2
11,658		559,400		559,400	3
			[redacted]	90	4
			[redacted]	63,455	5
3,521		[redacted]		111,661	6
163,100		7,926,306		7,926,306	7
1,045		[redacted]		44,450	8
2,200		95,260		95,260	9
853		[redacted]		44,466	10
3,400		141,250		141,250	11
23,416		[redacted]		907,915	12
76,142		4,346,801		4,346,801	13
4,167		[redacted]		120,868	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corporatio	SF	WSPP	n/a	n/a	n/a
2	Sacramento Municipal Utility Distri	SF	WSPP	n/a	n/a	n/a
3	Salt River Project	OS	WSPP	n/a	n/a	n/a
4	Seattle City Light	OS	WSPP	n/a	n/a	n/a
5	Seattle City Light	SF	WSPP	n/a	n/a	n/a
6	Sempra Energy Trading Corporation	OS	WSPP	n/a	n/a	n/a
7	Sempra Energy Trading Corporation	OS	WSPP	n/a	n/a	n/a
8	Sempra Energy Trading Corporation	OS	WSPP	n/a	n/a	n/a
9	Sempra Energy Trading Corporation	SF	WSPP	n/a	n/a	n/a
10	Sierra Pacific Power Company	OS	WSPP	n/a	n/a	n/a
11	Sierra Pacific Power Company	OS	WSPP	n/a	n/a	n/a
12	Sierra Pacific Power Company	SF	T-7	n/a	n/a	n/a
13	Snohomish County PUD	OS	WSPP	n/a	n/a	n/a
14	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
10,375		481,675		481,675	1
200		8,700		8,700	2
125		[redacted]		10,550	3
13,797		[redacted]		554,824	4
7,650		380,450		380,450	5
15,505		[redacted]		874,902	6
			[redacted]	221,952	7
292		[redacted]		18,869	8
821,161		33,994,471		33,994,471	9
9,536		[redacted]		547,360	10
			[redacted]	1,799,249	11
2		111		111	12
10,519		[redacted]		423,607	13
3,100		119,250		119,250	14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern California Edison	OS	WSPP	n/a	n/a	n/a
2	SUEZ Energy Marketing NA, Inc.	OS	WSPP	n/a	n/a	n/a
3	SUEZ Energy Marketing NA, Inc.	SF	WSPP	n/a	n/a	n/a
4	Tacoma Power	OS	WSPP	n/a	n/a	n/a
5	TransAlta Energy Marketing (U.S.) I	OS	WSPP	n/a	n/a	n/a
6	TransAlta Energy Marketing (U.S.) I	OS	WSPP	n/a	n/a	n/a
7	TransAlta Energy Marketing (U.S.) I	SF	WSPP	n/a	n/a	n/a
8	UBS AG, London Branch	SF	WSPP	n/a	n/a	n/a
9	Utah Associated Municipal Power Sys	OS	WSPP	n/a	n/a	n/a
10	Utah Associated Municipal Power Sys	OS	WSPP	n/a	n/a	n/a
11	Utah Associated Municipal Power Sys	SF	WSPP	n/a	n/a	n/a
12	LESS BAD DEBT WRITE-OFF					
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
9		[redacted]		574	1
2,614		[redacted]		114,202	2
94,404		5,093,638		5,093,638	3
54		[redacted]		900	4
			[redacted]	162	5
3,246		[redacted]		159,278	6
275,725		11,388,156		11,388,156	7
43,560		2,403,030		2,403,030	8
205		[redacted]		11,127	9
498		[redacted]		27,552	10
17,890		605,705		605,705	11
					12
					13
					14
108,970	783,696	2,175,142	526,433	3,485,271	
5,711,853	0	248,955,228	8,276,992	257,232,220	
5,820,823	**783,696**	**251,130,370**	**8,803,425**	**260,717,491**	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/18/2007	2006/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 Line No.: 3 Column: i
Prior year adjustment.

Schedule Page: 310 Line No.: 4 Column: j
Network transmission charges.

Schedule Page: 310 Line No.: 9 Column: i
Non-Firm sales.

Schedule Page: 310 Line No.: 10 Column: i
Unit Contingent.

Schedule Page: 310 Line No.: 11 Column: j
Financial Transmission Losses.

Schedule Page: 310 Line No.: 13 Column: i
Non-Firm sales.

Schedule Page: 310.1 Line No.: 1 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 2 Column: i
Unit Contingent.

Schedule Page: 310.1 Line No.: 3 Column: j
Financial Tranmission Losses.

Schedule Page: 310.1 Line No.: 6 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 7 Column: j
Financial Transmission Losses.

Schedule Page: 310.1 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 10 Column: i
Unit Contingent.

Schedule Page: 310.1 Line No.: 11 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 13 Column: i
Unit Contingent.

Schedule Page: 310.1 Line No.: 14 Column: i
Non-Firm Sales.

Schedule Page: 310.2 Line No.: 2 Column: i
Non-Firm Sales.

Schedule Page: 310.2 Line No.: 4 Column: i
Non-Firm Sales.

Schedule Page: 310.2 Line No.: 5 Column: j
Financial Transmission Losses.

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

Schedule Page: 310.2 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.2 Line No.: 11 Column: i
Non-Firm Sales.

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

Schedule Page: 310.3 Line No.: 1 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 5 Column: i
Unit Contingent.

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

Schedule Page: 310.3 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 9 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 11 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 12 Column: j
Spinning or Operating Reserves.

Schedule Page: 310.3 Line No.: 13 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 1 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 4 Column: i
Unit Contingent.

Schedule Page: 310.4 Line No.: 5 Column: j
Financial Transmission Losses.

Schedule Page: 310.4 Line No.: 6 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 8 Column: i
Unit Contingent.

Schedule Page: 310.4 Line No.: 9 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 12 Column: j
Capacity and Penalty Charge.

Schedule Page: 310.4 Line No.: 13 Column: i
Non-Firm Sales.

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

Schedule Page: 310.5 Line No.: 2 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.5 Line No.: 5 Column: j
Spinning or operating Reserves.

Schedule Page: 310.5 Line No.: 8 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 9 Column: i
Non-Firm Sales.

Schedule Page: 310.5 Line No.: 11 Column: j
Spinning or Operating Reserves.

Schedule Page: 310.5 Line No.: 12 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 13 Column: i
Non-Firm Losses.

Schedule Page: 310.6 Line No.: 1 Column: j
Financial Transmission Losses.

Schedule Page: 310.6 Line No.: 2 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 4 Column: j
Spinning or Operating Reserves.

Schedule Page: 310.6 Line No.: 5 Column: j
Financial Transmission Losses.

Schedule Page: 310.6 Line No.: 6 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 10 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 12 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 14 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 4 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 6 Column: i
Unit Contingent.

Schedule Page: 310.7 Line No.: 7 Column: j
Financial Transmission Losses.

Schedule Page: 310.7 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 10 Column: i
Unit Contingent.

Schedule Page: 310.7 Line No.: 11 Column: j
Financial Transmission Losses.

Schedule Page: 310.7 Line No.: 13 Column: i
Non-Firm Sales.

Schedule Page: 310.8 Line No.: 1 Column: i
Non-Firm Sales.

Schedule Page: 310.8 Line No.: 2 Column: i
Non-Firm Sales.

Schedule Page: 310.8 Line No.: 4 Column: i
Non-Firm Sales.

Schedule Page: 310.8 Line No.: 5 Column: j
Financial Transmission Losses.

Schedule Page: 310.8 Line No.: 6 Column: i
Non-Firm Losses.

Schedule Page: 310.8 Line No.: 9 Column: i
Unit Contingent.

Schedule Page: 310.8 Line No.: 10 Column: i
Non-Firm Sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	1,712,505	1,277,646
5	(501) Fuel	107,519,847	98,982,043
6	(502) Steam Expenses	7,107,143	6,895,514
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,444,277	1,610,776
10	(506) Miscellaneous Steam Power Expenses	8,142,999	6,795,112
11	(507) Rents	248,624	325,176
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	126,175,395	115,886,267
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,525,470	2,130,215
16	(511) Maintenance of Structures	408,848	421,603
17	(512) Maintenance of Boiler Plant	15,377,469	15,855,366
18	(513) Maintenance of Electric Plant	4,433,882	5,612,002
19	(514) Maintenance of Miscellaneous Steam Plant	4,575,617	1,240,867
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	27,321,286	25,260,053
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	153,496,681	141,146,320
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	4,522,312	4,556,943
45	(536) Water for Power	4,937,659	4,266,568
46	(537) Hydraulic Expenses	8,258,502	8,163,818
47	(538) Electric Expenses	1,387,391	1,264,687
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,407,071	1,894,576
49	(540) Rents	409,491	359,290
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	21,922,426	20,505,882
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,871,365	1,275,738
54	(542) Maintenance of Structures	1,193,327	899,749
55	(543) Maintenance of Reservoirs, Dams, and Waterways	946,682	683,950
56	(544) Maintenance of Electric Plant	2,138,733	2,466,384
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,213,655	2,854,670
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,363,762	8,180,491
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	31,286,188	28,686,373

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	322,341	390,680
63	(547) Fuel	7,498,309	4,181,468
64	(548) Generation Expenses	290,352	231,162
65	(549) Miscellaneous Other Power Generation Expenses	297,218	342,401
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	8,408,220	5,145,711
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	173	194
70	(552) Maintenance of Structures	176,972	255,394
71	(553) Maintenance of Generating and Electric Plant	124,319	30,292
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	392,516	428,740
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	693,980	714,620
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	9,102,200	5,860,331
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	283,439,877	222,310,315
77	(556) System Control and Load Dispatching	76,140	77,483
78	(557) Other Expenses	-27,304,586	-1,023,410
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	256,211,431	221,364,388
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	450,096,500	397,057,412
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,537,078	2,013,395
84	(561) Load Dispatching	1,166,233	2,971,942
85	(561.1) Load Dispatch-Reliability	565	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,525,337	
87	(561.3) Load Dispatch-Transmission Service and Scheduling	765,078	
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	29,062	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,866,905	1,591,008
94	(563) Overhead Lines Expenses	869,797	515,152
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	7,638,680	7,657,106
97	(566) Miscellaneous Transmission Expenses	270,768	297,608
98	(567) Rents	1,152,152	1,565,610
99	TOTAL Operation (Enter Total of lines 83 thru 98)	17,821,655	16,611,821
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	460,937	695,940
102	(569) Maintenance of Structures		68,184
103	(569.1) Maintenance of Computer Hardware	98,980	
104	(569.2) Maintenance of Computer Software	93,345	
105	(569.3) Maintenance of Communication Equipment	5,757	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,900,424	2,688,845
108	(571) Maintenance of Overhead Lines	2,257,538	1,908,500
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	31,222	16,446
111	TOTAL Maintenance (Total of lines 101 thru 110)	5,848,203	5,377,915
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,669,858	21,989,736

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,051,138	3,845,031
135	(581) Load Dispatching	3,020,110	2,536,857
136	(582) Station Expenses	1,159,883	945,089
137	(583) Overhead Line Expenses	3,856,696	2,967,382
138	(584) Underground Line Expenses	2,042,167	1,733,935
139	(585) Street Lighting and Signal System Expenses	154,596	120,630
140	(586) Meter Expenses	4,288,265	4,108,887
141	(587) Customer Installations Expenses	1,148,759	773,447
142	(588) Miscellaneous Expenses	5,589,808	4,603,412
143	(589) Rents	149,968	157,873
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,461,390	21,792,543
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	223,168	91,162
147	(591) Maintenance of Structures		69,106
148	(592) Maintenance of Station Equipment	2,826,028	2,629,976
149	(593) Maintenance of Overhead Lines	11,020,129	10,928,110
150	(594) Maintenance of Underground Lines	1,114,786	1,109,939
151	(595) Maintenance of Line Transformers	583,246	321,335
152	(596) Maintenance of Street Lighting and Signal Systems	711,171	378,751
153	(597) Maintenance of Meters	895,593	773,149
154	(598) Maintenance of Miscellaneous Distribution Plant	148,970	230,529
155	TOTAL Maintenance (Total of lines 146 thru 154)	17,523,091	16,532,057
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	41,984,481	38,324,600
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	537,023	494,549
160	(902) Meter Reading Expenses	5,254,777	4,723,518
161	(903) Customer Records and Collection Expenses	10,146,625	9,292,260
162	(904) Uncollectible Accounts	2,848,490	1,556,140
163	(905) Miscellaneous Customer Accounts Expenses	373	28,055
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	18,787,288	16,094,522

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	288,822	281,012
168	(908) Customer Assistance Expenses	9,047,316	8,575,566
169	(909) Informational and Instructional Expenses	200	
170	(910) Miscellaneous Customer Service and Informational Expenses	847,736	763,679
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	10,184,074	9,620,257
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	48,935,653	40,438,326
182	(921) Office Supplies and Expenses	14,665,999	16,117,873
183	(Less) (922) Administrative Expenses Transferred-Credit	29,324,259	23,657,334
184	(923) Outside Services Employed	8,149,646	7,823,980
185	(924) Property Insurance	2,945,897	2,866,971
186	(925) Injuries and Damages	5,152,000	5,711,625
187	(926) Employee Pensions and Benefits	29,241,894	22,956,720
188	(927) Franchise Requirements	2,000	2,300
189	(928) Regulatory Commission Expenses	976,225	4,009,949
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	107,310	120,381
192	(930.2) Miscellaneous General Expenses	1,901,158	1,856,141
193	(931) Rents	4,003	3,800
194	TOTAL Operation (Enter Total of lines 181 thru 193)	82,757,526	78,250,732
195	Maintenance		
196	(935) Maintenance of General Plant	3,969,367	3,473,712
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	86,726,893	81,724,444
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	631,449,094	564,810,971

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Willis and Betty Deveny	LU	-	N/A	N/A	N/A
2	James B. Howell/CHI	LU	-	N/A	N/A	N/A
3	[redacted]	LU	-	4.942Mw	N/A	N/A
4	Owyhee Irrigation District					
5	Mitchell Butte	LU	-	N/A	N/A	N/A
6	Owyhee Dam	LU	-	N/A	N/A	N/A
7	Tunnel #1	LU	-	N/A	N/A	N/A
8	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
9	Clifton E. Jenson	LU	-	.05Mw	N/A	N/A
10	Snake River Pottery	LU	-	N/A	N/A	N/A
11	White Water Ranch	LU	-	N/A	N/A	N/A
12	John R LeMoyne	LU	-	N/A	N/A	N/A
13	David R Snedigar	LU	-	N/A	N/A	N/A
14	Mud Creek Hydro, Inc	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	
851				54,265		54,265	1
3,595				238,848		238,848	2
38,177			1,576,498	1,160,069		2,736,567	3
							4
6,905				127,398		127,398	5
33,926				1,899,179		1,899,179	6
23,570				2,438,942		2,438,942	7
1,294				92,747		92,747	8
292			17,500	5,500		23,000	9
422				27,208		27,208	10
637				40,906		40,906	11
623				34,212		34,212	12
1,235				82,644		82,644	13
435				27,072		27,072	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Rim View Trout Company	[redacted]	-	N/A	N/A	N/A
2	Curry Cattle Company	LU	-	.084Mw	N/A	N/A
3	Branchflower Company	LU	-	N/A	N/A	N/A
4	Big Wood Canal Company					
5	Black Canyon	LU	-	N/A	N/A	N/A
6	Jim Knight	LU	-	N/A	N/A	N/A
7	Sagebrush	LU	-	N/A	N/A	N/A
8	Fisheries Development	[redacted]	-	N/A	N/A	N/A
9	Shorock Hydro Inc.					
10	Shoshone Cspp	LU	-	N/A	N/A	N/A
11	Shoshone #2	LU	-	N/A	N/A	N/A
12	Rock Creek #1 Joint Venture	LU	-	1.732Mw	N/A	N/A
13	Richard Kaster					
14	Box Canyon	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	04/18/2007	End of 2006/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)	
1,293				48,305		48,305	1
632			26,796	12,398		39,194	2
937				62,297		62,297	3
							4
335				22,276		22,276	5
1,508				101,147		101,147	6
1,305				87,193		87,193	7
975				35,244		35,244	8
							9
2,202				153,390		153,390	10
2,435				149,526		149,526	11
10,607			552,508	201,747		754,255	12
							13
1,630				102,695		102,695	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Briggs Creek	LU	-	N/A	N/A	N/A
2	David McCollum	LU	-	N/A	N/A	N/A
3	H.K. Hydro / Mud Creek S & S	LU	-	N/A	N/A	N/A
4	Allan/Vernon Ravenscroft	LU	-	.488Mw	N/A	N/A
5	William Arkoosh	LU	-	N/A	N/A	N/A
6	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
7	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
8	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
9	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
10	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
11	Pigeon Cove Power	LU	-	1.389	N/A	N/A
12	Consolidated Hydro Inc. / Enel		-			
13	GeoBon #2	LU	-	N/A	N/A	N/A
14	Barber Dam	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	04/18/2007	End of 2006/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)	
3,587				231,846		231,846	1
671				24,834		24,834	2
1,491				94,567		94,567	3
2,924			155,672	55,073		210,745	4
4,463				312,711		312,711	5
3,524				263,876		263,876	6
4,073				294,177		294,177	7
3,931				266,980		266,980	8
8,429				525,385		525,385	9
9,204				585,481		585,481	10
7,583			486,150	127,378		613,528	11
							12
4,089				282,593		282,593	13
18,588				842,088		842,088	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Rock Creek #2	LU	-	N/A	N/A	N/A
2	Dietrich Drop	LU	-	N/A	N/A	N/A
3	Lowline #2	LU	-	N/A	N/A	N/A
4	Cedar Draw/Little Mac Power Co.	LU	-	N/A	N/A	N/A
5	[redacted]	LU	-	N/A	N/A	N/A
6	Little Wood River Irrigation Dis	LU	-	N/A	N/A	N/A
7	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
10	Bypass Limited	LU	-	N/A	N/A	N/A
11	SE Hazelton A LP	LU	-	N/A	N/A	N/A
12	Jerry L McMillan	[redacted]	-	N/A	N/A	N/A
13	Lemhi HydroPower Company	LU	-	N/A	N/A	N/A
14	J R Simplot Co.	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) 04/18/2007	Year/Period of Report End of 2006/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)	
8,758				400,860		400,860	1
12,743				679,632		679,632	2
9,027				457,079		457,079	3
5,689				352,615		352,615	4
24,974				1,747,460		1,747,460	5
6,686				495,549		495,549	6
2,343				150,094		150,094	7
3,358				250,670		250,670	8
30,404				1,444,546		1,444,546	9
25,382				1,294,176		1,294,176	10
21,840				1,062,306		1,062,306	11
182				7,120		7,120	12
1,243				87,205		87,205	13
75,755				3,627,950		3,627,950	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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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	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
2	City of Hailey	LU	-	N/A	N/A	N/A
3	City of Pocatello	LU	-	N/A	N/A	N/A
4	[redacted]	LU	-	N/A	N/A	N/A
5	[redacted]	LU	-	N/A	N/A	N/A
6	[redacted]	LU	-	N/A	N/A	N/A
7	Pristine Springs Inc. #1	LU	-	N/A	N/A	N/A
8	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
9	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
10	Contractors Power Group Inc.	LU	-	N/A	N/A	N/A
11	Rupert Cogeneration Partners	LU	-	N/A	N/A	N/A
12	Glenns Ferry Cogeneration Partne	LU	-	N/A	N/A	N/A
13	Lewandowski Farms	[redacted]	-	N/A	N/A	N/A
14	Tasco - Nampa	[redacted]	-	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)	
4,977				366,120		366,120	1
60				3,794		3,794	2
1,409				98,610		98,610	3
54,725				3,277,235		3,277,235	4
24,883				1,622,442		1,622,442	5
21,895				1,424,144		1,424,144	6
860				42,042		42,042	7
17,282				1,070,464		1,070,464	8
47,465				2,981,566		2,981,566	9
3,969				261,557		261,557	10
77,882				4,736,407		4,736,407	11
69,840				4,143,010		4,143,010	12
152				8,416		8,416	13
539				21,783		21,783	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Pristine Springs Inc # 3	LU	-	N/A	N/A	N/A
2	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
3	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
4	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
5	Horseshoe Bend Wind/United Mater	LU	-	N/A	N/A	N/A
6	Horseshoe Bend Wind/United Mater	LU	-	N/A	N/A	N/A
7	Riverside Hydro Mora Drop	LU	-	N/A	N/A	N/A
8	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
9	D.R. Johnson Lumber/Co Gen Co	SF	-	N/A	N/A	N/A
10	American Electric Power Service	SF	WSPP	N/A	N/A	N/A
11	Arizona Public Service Co.	OS	WSPP	N/A	N/A	N/A
12	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
13	Avista Corp. - WWP Div.	SF	T-10	N/A	N/A	N/A
14	Avista Corp. - WWP Div.	SF	T-12	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	04/18/2007	End of 2006/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.
1,195				58,237		58,237	1
30,835				1,384,605		1,384,605	2
26,026				1,211,391		1,211,391	3
4,357				193,715		193,715	4
15,977				745,063		745,063	5
-6							6
1,195				56,476		56,476	7
721				31,809		31,809	8
68,126				3,942,586		3,942,586	9
72,800				2,975,620		2,975,620	10
10,898				202,114		202,114	11
114,867				6,293,479		6,293,479	12
					81,420	81,420	13
48				2,081		2,081	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
2	Avista Corp. - WWP Div.	SF	WSPP	N/A	N/A	N/A
3	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
4	Avista Energy, Inc.	OS	WSPP	N/A	N/A	N/A
5	Avista Energy, Inc.	SF	WSPP	N/A	N/A	N/A
6	Avista Energy, Inc.	SF	WSPP	N/A	N/A	N/A
7	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
8	Benton County PUD	OS	WSPP	N/A	N/A	N/A
9	Benton County PUD	SF	WSPP	N/A	N/A	N/A
10	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
11	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
12	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
13	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
14	Bonneville Power Administration	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	04/18/2007	End of 2006/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)	
15,833				634,440		634,440	1
6,321				251,697		251,697	2
					497,888	497,888	3
15,562				654,427		654,427	4
					250	250	5
55,986				2,223,723		2,223,723	6
1,000				61,550		61,550	7
2,702				65,976		65,976	8
1,591				84,795		84,795	9
8,695				428,384		428,384	10
5,293				285,434		285,434	11
114,542				4,885,549		4,885,549	12
					1,757,655	1,757,655	13
192,022				5,632,707		5,632,707	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
2	BP Energy Company	SF	WSPP	N/A	N/A	N/A
3	Burbank, City of	SF	WSPP	N/A	N/A	N/A
4	Calpine Energy Services, L.P.	[redacted]	WSPP	N/A	N/A	N/A
5	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
6	Cargill Power Markets LLC	[redacted]	WSPP	N/A	N/A	N/A
7	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
8	Chelan Co PUD	[redacted]	WSPP	N/A	N/A	N/A
9	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
10	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
11	Citigroup Energy Inc.	[redacted]	WSPP	N/A	N/A	N/A
12	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
13	Clatskanie PUD	[redacted]	WSPP	N/A	N/A	N/A
14	Clatskanie 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	04/18/2007	End of 2006/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)	
469				20,482		20,482	1
472,155				31,811,725		31,811,725	2
400				18,000		18,000	3
1,507				5,407		5,407	4
4,600				327,000		327,000	5
7,210				164,249		164,249	6
31,706				1,507,780		1,507,780	7
150				10,200		10,200	8
20,200				505,750		505,750	9
15				648		648	10
450				23,850		23,850	11
2,000				117,800		117,800	12
70				3,360		3,360	13
2,400				115,700		115,700	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Conoco Phillips Company	[redacted]	WSPP	N/A	N/A	N/A
2	Conoco Phillips Company	SF	WSPP	N/A	N/A	N/A
3	Constellation Energy Commodities	SF	WSPP	N/A	N/A	N/A
4	Coral Power, LLC	SF	WSPP	N/A	N/A	N/A
5	DB Energy Trading, LLC	SF	WSPP	N/A	N/A	N/A
6	Douglas County PUD	[redacted]	WSPP	N/A	N/A	N/A
7	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
8	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
9	El Paso Electric Company	[redacted]	WSPP	N/A	N/A	N/A
10	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
11	Eugene Water & Electric Board	[redacted]	WSPP	N/A	N/A	N/A
12	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
13	Franklin County P.U.D.	[redacted]	WSPP	N/A	N/A	N/A
14	Franklin County P.U.D.	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	04/18/2007	End of 2006/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.
1,615				207,625		207,625	1
5,000				475,850		475,850	2
78,440				3,313,307		3,313,307	3
305,600				21,726,300		21,726,300	4
800				37,550		37,550	5
480				5,600		5,600	6
2,800				156,000		156,000	7
2				83		83	8
165				6,495		6,495	9
3,601				252,120		252,120	10
1,560				39,535		39,535	11
13,200				452,750		452,750	12
1,144				19,992		19,992	13
1,376				68,910		68,910	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Grant County P.U.D.	OS	WSPP	N/A	N/A	N/A
2	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
3	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
4	Grays Harbor PUD	OS	WSPP	N/A	N/A	N/A
5	Grays Harbor PUD	SF	WSPP	N/A	N/A	N/A
6	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
7	Los Angeles Department of Water	OS	WSPP	N/A	N/A	N/A
8	Morgan Stanley Capital Group Inc	OS	WSPP	N/A	N/A	N/A
9	Morgan Stanley Capital Group Inc	SF	WSPP	N/A	N/A	N/A
10	Nevada Power Company	OS	WSPP	N/A	N/A	N/A
11	Northern California Power Agency	OS	WSPP	N/A	N/A	N/A
12	NorthWestern Energy	OS	WSPP	N/A	N/A	N/A
13	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
14	NorthWestern Energy	SF	T-7	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) 04/18/2007	Year/Period of Report End of 2006/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.
1,769				91,804		91,804	1
9,000				274,350		274,350	2
9				421		421	3
805				13,975		13,975	4
1,933				102,245		102,245	5
9,200				449,300		449,300	6
40				3,000		3,000	7
2,677				176,643		176,643	8
296,487				17,001,923		17,001,923	9
364				16,460		16,460	10
50				1,000		1,000	11
2,198				85,205		85,205	12
273				7,159		7,159	13
56				2,514		2,514	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	NorthWestern Energy	IF	242	N/A	N/A	N/A
2	Okanogan County P.U.D.	[redacted]	WSPP	N/A	N/A	N/A
3	Pacific Northwest Generating Coo	[redacted]	WSPP	N/A	N/A	N/A
4	Pacific Northwest Generating Coo	SF	WSPP	N/A	N/A	N/A
5	PacifiCorp Inc.	[redacted]	WSPP	N/A	N/A	N/A
6	PacifiCorp Inc.	[redacted]	WSPP	N/A	N/A	N/A
7	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
8	PacifiCorp Inc.	SF	T-13	N/A	N/A	N/A
9	PacifiCorp Inc.	[redacted]	WSPP	N/A	N/A	N/A
10	PacifiCorp Inc.	[redacted]	WSPP	N/A	N/A	N/A
11	Pinnacle West Capital Corporatio	[redacted]	WSPP	N/A	N/A	N/A
12	Pinnacle West Capital Corporatio	SF	WSPP	N/A	N/A	N/A
13	Portland General Electric Compan	[redacted]	-	N/A	N/A	N/A
14	Portland General Electric Compan	[redacted]	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	04/18/2007	End of 2006/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)	
95,612				4,034,733		4,034,733	1
230				2,300		2,300	2
235				4,230		4,230	3
4,000				65,800		65,800	4
				500		500	5
89,860				4,643,521		4,643,521	6
133,471				5,591,585		5,591,585	7
279				12,273		12,273	8
					13,035	13,035	9
					557,582	557,582	10
192				1,920		1,920	11
3,400				142,800		142,800	12
1,696				23,415		23,415	13
38,858				2,011,962		2,011,962	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Portland General Electric Compan	SF	WSPP	N/A	N/A	N/A
2	Portland General Electric Compan	SF	T-14	N/A	N/A	N/A
3	Portland General Electric Compan	[redacted]	WSPP	N/A	N/A	N/A
4	Powerex Corp.	[redacted]	WSPP	N/A	N/A	N/A
5	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
6	PPL Montana, LLC	[redacted]	WSPP	N/A	N/A	N/A
7	PPL Montana, LLC	SF	WSPP	N/A	N/A	N/A
8	PPL Montana, LLC	LF	WSPP	N/A	N/A	N/A
9	PPM Energy, Inc.	[redacted]	WSPP	N/A	N/A	N/A
10	PPM Energy, Inc.	SF	WSPP	N/A	N/A	N/A
11	Public Service Co. of Colorado	[redacted]	WSPP	N/A	N/A	N/A
12	Public Service Co. of Colorado	SF	WSPP	N/A	N/A	N/A
13	Public Service Company of New Me	[redacted]	WSPP	N/A	N/A	N/A
14	Public Service Company of New Me	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	04/18/2007	End of 2006/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.
230,987				14,982,155		14,982,155	1
65				2,990		2,990	2
					1,500	1,500	3
32,552				3,382,647		3,382,647	4
108,387				5,437,632		5,437,632	5
12,867				614,674		614,674	6
22,087				1,087,114		1,087,114	7
103,584				4,609,488		4,609,488	8
11,425				511,991		511,991	9
110,167				5,563,143		5,563,143	10
5,211				892,842		892,842	11
30,400				909,700		909,700	12
2,760				267,935		267,935	13
11,200				485,150		485,150	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	Public Service Company of New Me	[redacted]	WSPP	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	[redacted]	WSPP	N/A	N/A	N/A
3	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
4	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
5	Rainbow Energy Marketing Corpora	[redacted]	WSPP	N/A	N/A	N/A
6	Rainbow Energy Marketing Corpora	SF	WSPP	N/A	N/A	N/A
7	Salt River Project	[redacted]	WSPP	N/A	N/A	N/A
8	Salt River Project	SF	WSPP	N/A	N/A	N/A
9	Seattle City Light	[redacted]	WSPP	N/A	N/A	N/A
10	Seattle City Light	SF	WSPP	N/A	N/A	N/A
11	Seattle City Light	SF	WSPP	N/A	N/A	N/A
12	Sempra Energy Solutions	SF	WSPP	N/A	N/A	N/A
13	Sempra Energy Trading Corporatio	[redacted]	WSPP	N/A	N/A	N/A
14	Sempra Energy Trading Corporatio	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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)	
					480	480	1
20,828				1,036,027		1,036,027	2
56,749				2,039,133		2,039,133	3
60				2,767		2,767	4
4,154				181,006		181,006	5
17,599				770,423		770,423	6
1,834				120,422		120,422	7
200				8,600		8,600	8
32,764				894,768		894,768	9
33				1,355		1,355	10
20,941				635,311		635,311	11
2,400				97,100		97,100	12
524				10,000		10,000	13
592,418				41,786,401		41,786,401	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	[redacted]	WSPP	N/A	N/A	N/A
2	Sierra Pacific Power Company	[redacted]	WSPP	N/A	N/A	N/A
3	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
4	Sierra Pacific Power Company	SF	55	N/A	N/A	N/A
5	Sierra Pacific Power Company	[redacted]	WSPP	N/A	N/A	N/A
6	Silicon Valley Power	SF	WSPP	N/A	N/A	N/A
7	Snohomish County PUD	[redacted]	WSPP	N/A	N/A	N/A
8	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
9	Southern California Edison	SF	WSPP	N/A	N/A	N/A
10	Southwestern Public Service Comp	[redacted]	WSPP	N/A	N/A	N/A
11	SUEZ Energy Marketing NA, Inc.	[redacted]	WSPP	N/A	N/A	N/A
12	SUEZ Energy Marketing NA, Inc.	SF	WSPP	N/A	N/A	N/A
13	Tacoma Power	[redacted]	WSPP	N/A	N/A	N/A
14	Tacoma Power	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	04/18/2007	End of 2006/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)	
5,068				206,713		206,713	1
					3,806	3,806	2
28,050				1,298,088		1,298,088	3
32				1,525		1,525	4
					3,257	3,257	5
400				18,500		18,500	6
23,237				791,466		791,466	7
7,863				231,080		231,080	8
400				25,500		25,500	9
200				7,000		7,000	10
2,025				105,560		105,560	11
13,700				550,460		550,460	12
11,817				531,825		531,825	13
7				374		374	14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Tacoma Power	SF	WSPP	N/A	N/A	N/A
2	TransAlta Energy Marketing (U.S.	[redacted]	WSPP	N/A	N/A	N/A
3	TransAlta Energy Marketing (U.S.	SF	WSPP	N/A	N/A	N/A
4	Tri-State Generation and Transmi	[redacted]	WSPP	N/A	N/A	N/A
5	Tucson Electric Power Company	[redacted]	WSPP	N/A	N/A	N/A
6	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
7	UBS AG, London Branch	SF	WSPP	N/A	N/A	N/A
8	Utah Associated Municipal Power	[redacted]	WSPP	N/A	N/A	N/A
9	Utah Associated Municipal Power	SF	WSPP	N/A	N/A	N/A
10	Western Area Power Administratio	SF	WSPP	N/A	N/A	N/A
11	Net Metering Customers	OS	-	N/A	N/A	N/A
12	BAD DEBT WRITE-OFF	-	-	N/A	N/A	N/A
13	Power Exchanges					
14	Avista Energy, Inc.	EX	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	HTSP	BOBR		3,711	3,711	1
5	JBSN	HTSP		50	50	2
5	HTSP	M345		100	100	3
5	JBSN	LGBP		229	229	4
5	LGBP	JBSN		247	247	5
5	BOBR	M345		1,225	1,225	6
5	LGBP	M345		1,325	1,325	7
5	HTSP	JBSN		1,632	1,632	8
5	LGBP	BOBR		3,618	3,618	9
5	BOBR	LGBP		31,445	31,445	10
5	BOBR	LGBP		75	75	11
5	HTSP	BOBR		811	811	12
5	IPCO	BOBR		400	400	13
5	LGBP	BOBR		1,296	1,296	14
5	LOLO	M345		2,978	2,978	15
5	HTSP	BOBR		12,986	12,986	16
5	ENPR	M345		14,726	14,726	17
5	ENPR	BOBR		36,197	36,197	18
5	ENPR	BOBR		1,155	1,155	19
5	LGBP	M345		41,116	41,116	20
5	LGBP	M345		18,279	18,279	21
5	ENPR	BOBR		150	150	22
5	LYPK	M345		264	264	23
5	IPCO	LOLO		1,000	1,000	24
5	IPCO	BOBR		1,200	1,200	25
5	M345	LGBP		2,495	2,495	26
5	IPCO	LGBP		2,664	2,664	27
5	MLCK	BOBR		3,440	3,440	28
5	JBSN	M345		19,700	19,700	29
5	ENPR	M345		11,232	11,232	30
5	ENPR	M345		9,200	9,200	31
5	HTSP	M345		37,265	37,265	32
5	HTSP	BOBR		55,547	55,547	33
5	BOBR	M345		67,912	67,912	34
			0	**4,483,108**	**4,483,108**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Sierra Pacific Power	Bonneville Power Administratio	Sierra Pacific Power	NF
2	Sierra Pacific Power	Bonneville Power Administratio	Sierra Pacific Power	STF
3	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Sierra Pacific Power	Avista	Sierra Pacific Power	NF
5	Sierra Pacific Power	Avista	Sierra Pacific Power	STF
6	TransAlta Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
7				
8				
9				
10				
11				
12				
13				
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15				
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34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	LGBP	M345		214,907	214,907	1
5	LGBP	M345		2,400	2,400	2
5	JEFF	M345		297,156	297,156	3
5	LOLO	M345		406,795	406,795	4
5	LOLO	M345		4,200	4,200	5
5	BOBR	HTSP		70	70	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	4,483,108	4,483,108	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,005,921	-300,105		705,816	1
1,029,983	-75,259		954,724	2
530,638	503,143		1,033,781	3
2,187,604	-639,147		1,548,457	4
12,500			12,500	5
	12,836		12,836	6
		4,860	4,860	7
6,553	1,816		8,369	8
54,173			54,173	9
	224,731		224,731	10
	13,395		13,395	11
	262,809		262,809	12
		-1,774,632	-1,774,632	13
	14,105		14,105	14
	58,832		58,832	15
	22,310		22,310	16
	3		3	17
	29		29	18
	116		116	19
	332		332	20
	26,337		26,337	21
	155		155	22
	615		615	23
	1,992		1,992	24
	3,074		3,074	25
	464		464	26
	1,430		1,430	27
	142		142	28
	178		178	29
	262		262	30
	315		315	31
	787		787	32
	1,050		1,050	33
	3,937		3,937	34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,278		4,278	1
	4,881		4,881	2
	6,771		6,771	3
	13,505		13,505	4
	17,012		17,012	5
	19,437		19,437	6
	31,216		31,216	7
	33,919		33,919	8
	43,461		43,461	9
	44,270		44,270	10
	342,198		342,198	11
	33,250		33,250	12
	392,166		392,166	13
	419,466		419,466	14
	165		165	15
	179		179	16
	220		220	17
	249		249	18
	249		249	19
	543		543	20
	567		567	21
	873		873	22
	1,091		1,091	23
	1,990		1,990	24
	2,203		2,203	25
	3,534		3,534	26
	4,079		4,079	27
	4,113		4,113	28
	4,216		4,216	29
	7,512		7,512	30
	12,508		12,508	31
	20,367		20,367	32
	21,887		21,887	33
	65,884		65,884	34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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.
	154,081		154,081	1
	299,290		299,290	2
	596,420		596,420	3
	408		408	4
	450		450	5
	525		525	6
	7,870		7,870	7
	23,904		23,904	8
	27,361		27,361	9
	193,954		193,954	10
	265,395		265,395	11
	531,402		531,402	12
	17		17	13
	496		496	14
	1,396		1,396	15
	3,136		3,136	16
	5		5	17
	23		23	18
	23		23	19
	93		93	20
	172		172	21
	186		186	22
	186		186	23
	232		232	24
	419		419	25
	442		442	26
	991		991	27
	1,125		1,125	28
	1,339		1,339	29
	3,018		3,018	30
	3,423		3,423	31
	3,865		3,865	32
	4,581		4,581	33
	5,018		5,018	34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
	6,552		6,552	1
	6,641		6,641	2
	7,701		7,701	3
	8,334		8,334	4
	9,599		9,599	5
	12,046		12,046	6
	1,366		1,366	7
	13,858		13,858	8
	14,900		14,900	9
	16,221		16,221	10
	17,486		17,486	11
	23,434		23,434	12
	25,155		25,155	13
	27,512		27,512	14
	33,381		33,381	15
	48,542		48,542	16
	49,974		49,974	17
	71,167		71,167	18
	86,095		86,095	19
	88,574		88,574	20
	109,619		109,619	21
	37,830		37,830	22
	155,518		155,518	23
	174,556		174,556	24
	750		750	25
	373,404		373,404	26
	42		42	27
	335		335	28
	349		349	29
	2,576		2,576	30
	2,876		2,876	31
	4,013		4,013	32
	5,452		5,452	33
	7,468		7,468	34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
	12,938		12,938	1
	129		129	2
	257		257	3
	589		589	4
	635		635	5
	3,151		3,151	6
	3,408		3,408	7
	4,198		4,198	8
	9,307		9,307	9
	80,887		80,887	10
	164		164	11
	1,774		1,774	12
	2,307		2,307	13
	7,474		7,474	14
	17,175		17,175	15
	74,893		74,893	16
	84,928		84,928	17
	166,916		166,916	18
	48,500		48,500	19
	145,212		145,212	20
	197,330		197,330	21
	391		391	22
	688		688	23
	2,605		2,605	24
	3,126		3,126	25
	6,499		6,499	26
	6,939		6,939	27
	8,960		8,960	28
	51,314		51,314	29
	7,950		7,950	30
	45,270		45,270	31
	97,066		97,066	32
	144,686		144,686	33
	176,894		176,894	34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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.
	548,421		548,421	1
	17,609		17,609	2
	774,016		774,016	3
	987,065		987,065	4
	83,473		83,473	5
	578		578	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
4,827,372	**9,099,237**	**-1,769,772**	**12,156,837**	

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2011. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system pear 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 31,2014. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

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

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

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

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 expire December 31, 2007.

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

The agreement between Idaho Power Company and the City of Seattle expires December 31, 2007.

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

Monthly customer charge.

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

Adjustment for potential billing error for years 2000 thru 2006.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp - WWp Div	NF	159,949	159,949		686,324		686,324
2	Avista Corp - WWP Div	SFP	164,533	164,533	630,000			630,000
3	[redacted]	LFP	436,696	436,696	992,256		[redacted]	1,233,416
4	[redacted]	LFP			43,596		[redacted]	54,036
5	Bonneville Power Admin	NF	8,264	8,264		28,925	[redacted]	35,891
6	Morgan Stanley Cap Grp	NF	21,648	21,648		60,336		60,336
7	Northwestern Energy	NF	6,754	6,754		56,973		56,973
8	NorthWesern Energy	SFP	90,844	90,844	744,600			744,600
9	[redacted]	LFP	106,847	106,847	204,000	14,889		218,889
10	NorthWestern Energy	OS					[redacted]	15,380
11	PacifiCorp Inc.	NF	93,902	93,902		549,989		549,989
12	PacifiCorp Inc.	SFP	135,834	135,834	2,089,192			2,089,192
13	PPL Montana LLC	NF					[redacted]	-34,800
14	Seattle City Light	NF	36,634	36,634		128,290		128,290
15	Sierra Pacific Power Co	NF	1,788	1,788		7,618	[redacted]	8,307
16	Snohomish County PUD	NF	346,440	346,440		916,728		916,728
	TOTAL		1,676,765	1,676,765	4,703,644	2,695,201	239,835	7,638,680

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Tacoma Power	NF	66,632	66,632		245,129		245,129
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,676,765	1,676,765	4,703,644	2,695,201	239,835	7,638,680

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/18/2007	2006/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 3 Column: a

Contract Expiration date is 9/30/2016

Schedule Page: 332 Line No.: 3 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 4 Column: a

Contact Expiration Date is 7/16/2011.

Schedule Page: 332 Line No.: 4 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 5 Column: g

Ancillary Services.

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

Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 10 Column: g

Transmission Study Fee.

Schedule Page: 332 Line No.: 13 Column: g

Resale Transmission.

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

Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	331,304
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	122,197
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	493,650
6	Rotchford Barker	26,294
7	Christine King	3,710
8	Jack Lemley	23,595
9	Jon Miller	42,328
10	Gary Michael	29,375
11	Peter O'Neill	26,100
12	Richard Reiten	21,752
13	Thomas Wilford	21,875
14	Robert Tintsman	26,250
15	Joan Smith	17,905
16	Jan Packwood	8,125
17		
18	Chambers of Commerce & Other Civic Organizations	91,690
19		
20		
21		
22	Associated Taxpayers of Idaho	21,252
23	Association of Idaho Cities	2,750
24	Corporate Executive Board	72,150
25	Eastern Oregon Visitor Association	1,500
26	Idaho Association of Commerce and Industry	9,400
27	Idaho Mining Association	2,025
28	Idaho Water Users	1,200
29	Misc Memberships (6)	1,135
30	National HydroPower Assoc	25,214
31	Oregonians For Food & Shelter	1,320
32	Pacific Nw Utilities	34,919
33	The Conference Board	2,625
34	Utility Wind Interest Group	5,000
35	West Associates	22,580
36	Western Electricity Coordiniating Council	376,570
37	Western Energy Institute	21,000
38	Wyoming Taxpayers Assoc	2,783
39		
40	Miscellaneous General Management:	
41	New York Stock Exchange	9,205
42	PR Newswire	2,380
43		
44		
45		
46	TOTAL	1,901,158

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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)	
14,110				663,980		663,980	1
2,060				101,300		101,300	2
223,577				14,222,257		14,222,257	3
400				23,946		23,946	4
366				18,516		18,516	5
3,001				214,800		214,800	6
13,960				665,020		665,020	7
139				6,335		6,335	8
320				4,800		4,800	9
1				41		41	10
				5		5	11
					2	2	12
							13
	4,800	4,800					14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	EX	WSPP			
2	Black Hills Power Inc.	[redacted]	-			
3	Bonneville Power Administration	[redacted]	-			
4	NorthWestern Energy, L.L.C.	[redacted]	-			
5	PacifiCorp Inc.	[redacted]	-			
6	Puget Sound Energy, Inc.	[redacted]	-			
7	Sierra Pacific Power Company	[redacted]	-			
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
	5,034	5,034					1
	41						2
	52,829	7,966					3
		4,242					4
	37,024	234,608					5
	29						6
		12,206					7
							8
							9
							10
							11
							12
							13
							14
4,964,024	99,757	268,856	2,815,124	277,707,878	2,916,875	283,439,877	

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

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

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

Non-Firm Purchases.

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

Non-Firm Purchases.

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

Ida-West a subsidiary of IdaCorp the parent of Idaho Power Company has partial ownership of these projects.

Schedule Page: 326.3 Line No.: 12 Column: b

Non-Firm Purchases.

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

Ida-West a Subsidiary of IdaCorp the Parent of Idaho Power Company has partial ownership of thest projects.

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

Ida-West a susidiary of IdaCorp the Parent of Idaho Power Company, has partial ownership of these projects.

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

Ida-West a subsidiary of IdaCorp the Parent of Idaho Power Company has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 13 Column: b

Non-Firm Purchases.

Schedule Page: 326.4 Line No.: 14 Column: b

Non-Firm Purchases.

Schedule Page: 326.5 Line No.: 6 Column: b

Energy difference between mountain and pacific time schedules.

Schedule Page: 326.5 Line No.: 11 Column: b

Non-Firm Purchases.

Schedule Page: 326.5 Line No.: 13 Column: b

Spinning or Operating Reserves.

Schedule Page: 326.6 Line No.: 1 Column: b

Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 3 Column: b

Financial Transmission Losses.

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

Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 5 Column: b

Spinning or Operating Reserves.

Schedule Page: 326.6 Line No.: 8 Column: b

Non-Firm Purhcases.

Schedule Page: 326.6 Line No.: 10 Column: b

Non-Firm Purchases.

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

Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 13 Column: b

Spinning or Operating Reserves.

Schedule Page: 326.7 Line No.: 4 Column: b

Non-Firm Purchases.

Schedule Page: 326.7 Line No.: 6 Column: b

Non-Firm Purchases.

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

Non-Firm Purchases.

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report 2006/Q4

FOOTNOTE DATA

Schedule Page: 326.7 Line No.: 11 Column: b
Non-Firm Purchases.
Schedule Page: 326.7 Line No.: 13 Column: b
Non-Firm Purchases.
Schedule Page: 326.8 Line No.: 1 Column: b
Non-Firm Purchases.
Schedule Page: 326.8 Line No.: 6 Column: b
Non-Firm Purchases.
Schedule Page: 326.8 Line No.: 9 Column: b
Non-Firm Purchases.
Schedule Page: 326.8 Line No.: 11 Column: b
Non-Firm Purhcases.
Schedule Page: 326.8 Line No.: 13 Column: b
Non-Firm Purhcases.
Schedule Page: 326.9 Line No.: 1 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 4 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 7 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 8 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 10 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 11 Column: b
Non-Firm Purchases.
Schedule Page: 326.9 Line No.: 12 Column: b
Non-Firm Purchases.
Schedule Page: 326.10 Line No.: 2 Column: b
Non-Firm Purchases.
Schedule Page: 326.10 Line No.: 3 Column: b
Non-Firm Purchases.
Schedule Page: 326.10 Line No.: 5 Column: b
2005 Price Adjustment.
Schedule Page: 326.10 Line No.: 6 Column: b
Non-Firm Purchases.
Schedule Page: 326.10 Line No.: 9 Column: b
Spinning or Operating Reserves.
Schedule Page: 326.10 Line No.: 10 Column: b
Financial Transmission Losses.
Schedule Page: 326.10 Line No.: 11 Column: b
Non-Firm Purchases.
Schedule Page: 326.10 Line No.: 13 Column: b
Energy received from PGE in lieu of Boardman generation in accordance with the "Assured" energy agreement between PGE and Idaho Power, dated 11/17/1989.
Schedule Page: 326.10 Line No.: 14 Column: b
Non-Firm Purchases.
Schedule Page: 326.11 Line No.: 3 Column: b
Spinning or Operating Reserves.
Schedule Page: 326.11 Line No.: 4 Column: b
Non-Firm Purchases.
Schedule Page: 326.11 Line No.: 6 Column: b
Non-Firm Purchases.
Schedule Page: 326.11 Line No.: 9 Column: b
Non-Firm Purchases.

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FOOTNOTE DATA

Schedule Page: 326.11 Line No.: 11 Column: b
Non-Firm Purchases.
Schedule Page: 326.11 Line No.: 13 Column: b
Non-Firm Purchases.
Schedule Page: 326.12 Line No.: 1 Column: b
Spinning or Operating Reserves.
Schedule Page: 326.12 Line No.: 2 Column: b
Non-Firm Purchases.
Schedule Page: 326.12 Line No.: 5 Column: b
Non-Firm Purchases.
Schedule Page: 326.12 Line No.: 7 Column: b
Non-Firm Purchases.
Schedule Page: 326.12 Line No.: 9 Column: b
Non-Firm Purchases.
Schedule Page: 326.12 Line No.: 13 Column: b
Non-Firm Purchases.
Schedule Page: 326.13 Line No.: 1 Column: b
Non-Firm Purchases.
Schedule Page: 326.13 Line No.: 2 Column: b
Spinning or Operating Reserves.
Schedule Page: 326.13 Line No.: 5 Column: b
Financial Transmission Losses.
Schedule Page: 326.13 Line No.: 7 Column: b
Non-Firm Purchases.
Schedule Page: 326.13 Line No.: 10 Column: b
Non-Firm Purchases.
Schedule Page: 326.13 Line No.: 11 Column: b
Non-Firm Purchases.
Schedule Page: 326.13 Line No.: 13 Column: b
Non-Firm Purchases.
Schedule Page: 326.14 Line No.: 2 Column: b
Non-Firm Purchases.
Schedule Page: 326.14 Line No.: 4 Column: b
Non-Firm Purchases.
Schedule Page: 326.14 Line No.: 5 Column: b
Non-Firm Purchases.
Schedule Page: 326.14 Line No.: 8 Column: b
Non-Firm Purchases.
Schedule Page: 326.15 Line No.: 2 Column: b
Scheduled losses not removed with loss transactions.
Schedule Page: 326.15 Line No.: 3 Column: b
Scheduled losses not removed with loss transactions.
Schedule Page: 326.15 Line No.: 4 Column: b
Scheduled losses not removed with loss transactions.
Schedule Page: 326.15 Line No.: 5 Column: b
Scheduled losses not removed with loss transactions.
Schedule Page: 326.15 Line No.: 6 Column: b
Scheduled losses not removed with loss transactions.
Schedule Page: 326.15 Line No.: 7 Column: b
Scheduled losses not removed with loss transactions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	[redacted]	Bonneville Power Administratio	Oregon Trails Electric Co-op	FNO
2	[redacted]	Bonneville Power Administratio	United States Bureau of Reclama	FNO
3	[redacted]	Bonneville Power Administratio	Raft River Electric Co-op	FNO
4	[redacted]	Bonneville Power Administratio	Priority Firm Customers	FNO
5	[redacted]	Bonneville Power Administratio	Vigilante	OLF
6	[redacted]	United States Bureau of Reclam	Milner Irrigation District	OLF
7	[redacted]	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 Power Marketing	PacifiCorp West	PacifiCorp West	OLF
11	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp West	OLF
12	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	OLF
13	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp West	AD
14	Arizona Public Service	Idaho Power Company	PacifiCorp East	NF
15	Arizona Public Service	PacifiCorp East	Sierra Pacific Power	NF
16	Arizona Public Service	PacifiCorp East	Sierra Pacific Power	STF
17	Avista Corp.	PacifiCorp East	Avista	NF
18	Avista Energy, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
19	Avista Energy, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Avista Energy, Inc.	Bonneville Power Administratio	Sierra Pacific Power	NF
21	Avista Energy, Inc.	PacifiCorp East	Sierra Pacific Power	NF
22	Black Hills Power	PacifiCorp West	NorthWestern/PacifiCorp East	NF
23	Black Hills Power	Bonneville Power Administratio	PacifiCorp West	NF
24	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
25	Black Hills Power	PacifiCorp East	Bonneville Power Administration	NF
26	Boneville Power Admin.	PacifiCorp West	Sierra Pacific Power	NF
27	Boneville Power Admin.	Bonneville Power Administratio	Sierra Pacific Power	NF
28	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
29	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	NF
30	Cargill Power Markets	Idaho Power Company	PacifiCorp East	NF
31	Cargill Power Markets	PacifiCorp West	NorthWestern/PacifiCorp East	NF
32	Cargill Power Markets	Bonneville Power Administratio	PacifiCorp West	NF
33	Cargill Power Markets	PacifiCorp West	NorthWestern/PacifiCorp East	NF
34	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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				326,466	326,466	1
5				191,344	191,344	2
5				184,368	184,368	3
5				763,201	763,201	4
5	Bannack Tap	Vigilante Electric				5
0	Minidoka, Idaho	Various in Idaho		7,923	7,923	6
0	LYPK	LGBP				7
5				2,111	2,111	8
0	LaGrande, Oregon	Various in Idaho		14,810	14,810	9
0	JBSN	ENPR		77,170	77,170	10
0	JBSN	ENPR		4,362	4,362	11
0	BOBR	JBSN		70,938	70,938	12
0	JBSN	ENPR				13
5	IPCO	BOBR		11,075	11,075	14
5	BOBR	M345		46,598	46,598	15
5	BOBR	M345		17,112	17,112	16
5	BOBR	LOLO		1	1	17
5	M345	LGBP		12	12	18
5	HTSP	M345		48	48	19
5	LGBP	M345		137	137	20
5	BOBR	M345		10,852	10,852	21
5	JBSN	HTSP		50	50	22
5	LGBP	JBSN		199	199	23
5	JBSN	LGBP		644	644	24
5	BOBR	LGBP		994	994	25
5	JBSN	M345		76	76	26
5	LGBP	M345		234	234	27
5	HTSP	M345		27	27	28
5	BOBR	LGBP		34	34	29
5	IPCO	BOBR		50	50	30
5	JBSN	HTSP		60	60	31
5	LGBP	JBSN		150	150	32
5	ENPR	HTSP		200	200	33
5	JBSN	ENPR		750	750	34
			0	**4,483,108**	**4,483,108**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	IPCO	LGBP		815	815	1
5	JBSN	BOBR		930	930	2
5	LOLO	M345		1,290	1,290	3
5	LGBP	M345		2,573	2,573	4
5	BOBR	HTSP		3,241	3,241	5
5	HTSP	BOBR		3,703	3,703	6
5	JBSN	M345		5,947	5,947	7
5	ENPR	JBSN		6,462	6,462	8
5	LGBP	BOBR		8,280	8,280	9
5	JBSN	LGBP		8,434	8,434	10
5	ENPR	BOBR		45,573	45,573	11
5	ENPR	BOBR		25,955	25,955	12
5	BOBR	M345		74,713	74,713	13
5	ENPR	M345		79,914	79,914	14
5	BOBR	LOLO		69	69	15
5	ENPR	JBSN		75	75	16
5	IPCO	LGBP		92	92	17
5	LOLO	BOBR		104	104	18
5	LYPK	LOLO		104	104	19
5	IPCO	BOBR		227	227	20
5	LOLO	M345		237	237	21
5	ENPR	BOBR		365	365	22
5	HTSP	M345		456	456	23
5	JBSN	BOBR		832	832	24
5	BOBR	HTSP		921	921	25
5	JBSN	LGBP		1,477	1,477	26
5	BOBR	ENPR		1,705	1,705	27
5	LGBP	M345		1,719	1,719	28
5	ENPR	M345		1,762	1,762	29
5	LGBP	BOBR		3,140	3,140	30
5	LYPK	LGBP		5,228	5,228	31
5	BOBR	LGBP		8,513	8,513	32
5	LYPK	BOBR		9,148	9,148	33
5	HTSP	BOBR		27,538	27,538	34
			0	**4,483,108**	**4,483,108**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
2	Morgan Stanley Capital Group	Seattle City Light	Sierra Pacific Power	NF
3	Morgan Stanley Capital Group	Seattle City Light	Sierra Pacific Power	NF
4	Pacificorp Power Marketing	Sierra Pacific Power	PacifiCorp East	NF
5	Pacificorp Power Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Pacificorp Power Marketing	Sierra Pacific Power	PacifiCorp West	NF
7	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
8	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
9	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
10	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
11	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
12	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
13	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
14	Portland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF
15	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
16	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
17	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
18	Powerex Corp.	Bonneville Power Administratio	Idaho Power Company	NF
19	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF
20	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF
22	Powerex Corp.	PacifiCorp West	Avista	NF
23	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
24	Powerex Corp.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
25	Powerex Corp.	Sierra Pacific Power	PacifiCorp West	NF
26	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF
27	Powerex Corp.	Avista	PacifiCorp West	NF
28	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
29	Powerex Corp.	PacifiCorp West	NorthWestern/PacifiCorp East	NF
30	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
31	Powerex Corp.	Avista	PacifiCorp East	STF
32	Powerex Corp.	Sierra Pacific Power	Idaho Power Company	NF
33	Powerex Corp.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	BOBR	M345		64,402	64,402	1
5	LYPK	M345		40,893	40,893	2
5	LYPK	M345		333,491	333,491	3
5	M345	BOBR		136	136	4
5	HTSP	BOBR		150	150	5
5	M345	ENPR		175	175	6
5	BOBR	M500		2,625	2,625	7
5	JBSN	BOBR		7,973	7,973	8
5	JBSN	M345		9,126	9,126	9
5	ENPR	M345		64,691	64,691	10
5	BOBR	ENPR		88,519	88,519	11
5	ENPR	BOBR		177,242	177,242	12
5	HTSP	LGBP		5	5	13
5	M345	LGBP		150	150	14
5	BOBR	LGBP		422	422	15
5	JEFF	LGBP		948	948	16
5	JBSN	M500		1	1	17
5	LGBP	IPCO		5	5	18
5	MLCK	BOBR		5	5	19
5	JEFF	BOBR		20	20	20
5	M345	BOBR		37	37	21
5	JBSN	LOLO		40	40	22
5	JEFF	ENPR		40	40	23
5	M345	HTSP		50	50	24
5	M345	ENPR		90	90	25
5	BOBR	JBSN		95	95	26
5	LOLO	JBSN		213	213	27
5	BOBR	JEFF		242	242	28
5	JBSN	JEFF		288	288	29
5	JBSN	ENPR		649	649	30
5	LOLO	BOBR		736	736	31
5	M345	IPCO		831	831	32
5	JEFF	M345		985	985	33
5	JBSN	BOBR		1,079	1,079	34
			0	**4,483,108**	**4,483,108**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	LGBP		1,409	1,409	1
5	JBSN	M345		1,428	1,428	2
5	HTSP	M345		1,656	1,656	3
5	BOBR	LOLO		1,792	1,792	4
5	BOBR	ENPR		2,064	2,064	5
5	LOLO	M345		2,596	2,596	6
5	LOLO	M345		288	288	7
5	ENPR	JBSN		2,980	2,980	8
5	LGBP	JBSN		3,204	3,204	9
5	HTSP	LGBP		3,488	3,488	10
5	BOBR	M345		3,760	3,760	11
5	LGBP	BOBR		5,039	5,039	12
5	JBSN	HTSP		5,409	5,409	13
5	IPCO	BOBR		5,916	5,916	14
5	BOBR	IPCO		7,178	7,178	15
5	IPCO	LGBP		10,438	10,438	16
5	BOBR	HTSP		10,746	10,746	17
5	M345	LGBP		15,303	15,303	18
5	ENPR	BOBR		18,513	18,513	19
5	HTSP	BOBR		19,046	19,046	20
5	LGBP	M345		29,981	29,981	21
5	LGBP	M345		1,725	1,725	22
5	JBSN	LGBP		33,441	33,441	23
5	ENPR	M345		37,296	37,296	24
5	ENPR	M345		400	400	25
5	BOBR	LGBP		80,293	80,293	26
5	LOLO	M345		12	12	27
5	BOBR	LGBP		96	96	28
5	LGBP	JBSN		100	100	29
5	ENPR	JBSN		739	739	30
5	JEFF	LOLO		825	825	31
5	LOLO	JBSN		1,151	1,151	32
5	JEFF	LGBP		1,564	1,564	33
5	HTSP	BOBR		2,142	2,142	34
			0	**4,483,108**	**4,483,108**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PP & L Montana	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	PPM Energy	PacifiCorp West	NorthWestern/PacifiCorp East	NF
3	PPM Energy	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	PPM Energy	PacifiCorp West	Bonneville Power Administration	NF
5	PPM Energy	Bonneville Power Administratio	PacifiCorp West	NF
6	PPM Energy	PacifiCorp East	Sierra Pacific Power	NF
7	PPM Energy	Bonneville Power Administratio	Sierra Pacific Power	NF
8	PPM Energy	NorthWestern/PacifiCorp East	PacifiCorp West	NF
9	PPM Energy	Bonneville Power Administratio	PacifiCorp East	NF
10	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
11	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF
12	Puget Sound Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
13	Sempra Energy Trading Corp	Idaho Power Company	PacifiCorp East	NF
14	Sempra Energy Trading Corp	Bonneville Power Administratio	PacifiCorp East	NF
15	Sempra Energy Trading Corp	Avista	Sierra Pacific Power	NF
16	Sempra Energy Trading Corp	NorthWestern/PacifiCorp East	PacifiCorp East	ST
17	Sempra Energy Trading Corp	PacifiCorp West	Sierra Pacific Power	NF
18	Sempra Energy Trading Corp	PacifiCorp West	PacifiCorp East	NF
19	Sempra Energy Trading Corp	PacifiCorp West	PacifiCorp East	STF
20	Sempra Energy Trading Corp	Bonneville Power Administratio	Sierra Pacific Power	NF
21	Sempra Energy Trading Corp	Bonneville Power Administratio	Sierra Pacific Power	STF
22	Sierra Pacific Power	PacifiCorp West	PacifiCorp East	NF
23	Sierra Pacific Power	Seattle City Light	Sierra Pacific Power	NF
24	Sierra Pacific Power	Idaho Power Company	Avista	NF
25	Sierra Pacific Power	Idaho Power Company	PacifiCorp East	NF
26	Sierra Pacific Power	Sierra Pacific Power	Bonneville Power Administration	NF
27	Sierra Pacific Power	Idaho Power Company	Bonneville Power Administration	NF
28	Sierra Pacific Power	PacifiCorp East	PacifiCorp East	NF
29	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
30	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
31	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	STF
32	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Sierra Pacific Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

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

Recipient	Purpose	Amount
Pete Wilson	2005 Annual Report	$ 49,450
AMBAC Assurance Corp	Annual premium on Humbolt	52,290
Amort of Prepaid Exp	Deutche Bank	12,233
Business Plus	Contribution	6,000
Deutsche Bank	Broker Fees	190,499
Deutsche Bank Trust	Fee Humbolt County	5,000
Georgeson Shareholder	Letter of Agreement	10,764
Global Insight	Data Subscription	23,391
J P Morgan Trust	Sweetwater & PC Bonds	15,265
Misc Customers	WECC	8,365
Option Expense	Directors Restriced Stock	32,995
Port of Morrow	Port of Morrow Bond Manage	5,475
Prepaid Contract Acctg	Amort of Deutsche Bank	23,760
RSP, PS, TSR & DSP	Directors Restricted Stock	10,683
Union Bank of California	Sweetwater & PC Bonds	13,887
Wells Fargo Shareowner Service	Wells Fargo - Transfer	29,304
Other items under $5,000	Misc	4,289

Total		$493,650
		========

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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			9,089,661		9,089,661
2	Steam Production Plant	23,623,910				23,623,910
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,606,566				12,606,566
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	3,035,377				3,035,377
7	Transmission Plant	12,905,223				12,905,223
8	Distribution Plant	27,682,064				27,682,064
9	Regional Transmission and Market Operation	11,246,569				11,246,569
10	General Plant	-296,299				-296,299
11	Common Plant-Electric					
12	TOTAL	90,803,410		9,089,661		99,893,071

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2006 Amortization	Balance to be amortized 12/31/06	Remaining months of amortization 12/31/06
(1)	24,000	12,000	12,000	12
(2)	12,659,523	400,503	13,283,905	-
(3)	18,007,166	8,376,719	13,726,106	-
(4)	234,830	12,252	222,578	218
(5)	6,340,123	288,187	6,051,936	252
TOTAL	37,265,642	9,089,661	33,296,528	

(1) Shoshone-Bannock Tribe license and use agreement (termination date December 31, 2023).
(2) Middle snake relicensing costs (amortized over a 30-year liscense period).
(3) Computer software packages (amortized over a 60 month period from date of purchase).
(4) American Falls dam road rebuild (termination date February 28, 2025).
(5) Shoshone-Bannock Right of Way (termination date December 31, 2028).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	130,537	90.00	-10.00	2.59	S1.0	18.30
14	312.10	77,980	55.00	-10.00	2.76	R3.0	19.10
15	312.20	423,501	70.00	-10.00	2.89	R1.5	18.10
16	312.30	3,977	25.00	20.00	2.77	R3.0	16.40
17	314.00	122,586	50.00	-10.00	3.46	S0.5	17.20
18	315.00	61,359	65.00		2.16	S1.5	17.80
19	316.00	11,307	45.00		3.07	R0.5	16.40
20	316.10	59	9.00	25.00	1.78	L3.0	9.00
21	316.40	226	9.00	25.00	3.44	L3.0	5.40
22	316.50	124	9.00	25.00	8.45	L3.0	3.50
23	316.70	251	17.00	25.00	4.26	S2.5	8.10
24	316.80	1,115	14.00	35.00	7.01	L0.5	9.40
25	317.000	3,837					
26	Subtotal Steam	837,062					
27	331.00	133,690	100.00	-20.00	2.37	S1.0	36.80
28	332.10	19,460	85.00	-10.00	1.93	S4.0	31.40
29	332.20	219,561	85.00	-10.00	1.93	S4.0	34.10
30	332.30	5,600	69.00		1.44	SQUARE	63.60
31	333.00	187,441	80.00	-5.00	1.83	R3.0	38.00
32	334.00	36,770	47.00		2.85	R1.5	28.00
33	335.00	15,624	100.00		1.86	S0.0	34.90
34	336.00	6,950	75.00		1.95	R3.0	34.70
35	Subtotal Hydro	625,096					
36	341.00	5,302	35.00		2.84	SQUARE	34.50
37	342.00	3,521	35.00		2.83	SQUARE	33.90
38	343.00	29,957	35.00		2.88	SQUARE	34.50
39	344.00	61,685	35.00		2.84	SQUARE	34.50
40	345.00	4,682	35.00		2.79	SQUARE	34.50
41	346.00	1,386	35.00		2.88	SQUARE	34.50
42	Subtotal Other	106,533					
43	350.20	22,455	65.00		1.54	R3.0	52.30
44	350.21	3,838	24.00		4.09	SQUARE	24.00
45	352.00	36,779	60.00	-20.00	1.29	R3.0	48.00
46	353.00	245,791	45.00	-5.00	2.12	S0.5	32.70
47	354.00	98,004	60.00	-30.00	2.45	S4.0	37.30
48	355.00	77,282	55.00	-60.00	2.94	R2.0	39.90
49	356.00	120,017	60.00	-20.00	1.96	R2.0	41.40
50	359.00	318	65.00		1.07	R3.0	27.00

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Subtotal Transmission	604,484					
13	361.00	20,494	55.00	-20.00	2.05	R2.5	40.70
14	362.00	142,958	50.00		1.64	O1.0	43.60
15	364.00	194,702	41.00	-50.00	3.67	R1.5	29.80
16	365.00	98,919	46.00	-30.00	3.25	R2.0	29.50
17	366.00	43,632	60.00	-25.00	2.04	R2.0	51.90
18	367.00	162,350	37.00	-10.00	2.73	S1.5	28.60
19	368.00	318,765	35.00	5.00	1.73	R2.0	27.10
20	369.00	51,272	30.00	-30.00	3.69	S2.0	20.50
21	370.00	52,622	30.00		4.06	L2.0	19.70
22	371.10	359	8.00		28.42	S5.0	2.30
23	371.20	2,275	11.00	-20.00	11.85	R0.5	7.00
24	373.00	4,067	20.00	-20.00	5.75	R1.0	10.90
25	374.00	370					
26	Subtotal Distribution	1,092,785					
27	390.11	25,833	100.00	-5.00	2.27	S1.5	38.50
28	390.12	31,213	50.00	-5.00	2.17	R3.0	36.00
29	390.20	7,345	25.00		3.85	S3.0	16.90
30	391.10	11,787	20.00		9.66	SQUARE	7.70
31	391.20	22,696	5.00		20.00	SQUARE	5.00
32	391.21	2,868	6.00		16.67	S5.0	6.00
33	392.10	323	9.00	25.00	1.78	L3.0	7.90
34	392.30	2,580	15.00	50.00	3.79	S2.0	15.00
35	392.40	17,830	9.00	25.00	3.45	L3.0	6.90
36	392.50	523	9.00	25.00	9.45	L3.0	9.00
37	392.60	22,448	17.00	25.00	4.72	S2.5	10.20
38	392.70	3,796	17.00	25.00	4.26	S2.5	7.90
39	392.90	3,551	30.00	25.00	1.93	S1.0	21.90
40	393.00	982	25.00		7.89	SQUARE	8.70
41	394.00	4,222	20.00		8.31	SQUARE	8.10
42	395.00	9,761	20.00		6.53	SQUARE	9.80
43	396.00	7,307	14.00	35.00	6.99	L0.5	7.70
44	397.10	6,914	15.00		11.61	SQUARE	5.70
45	397.20	17,234	15.00		9.99	SQUARE	7.40
46	397.30	2,623	15.00		9.99	SQUARE	6.70
47	397.40	1,426	10.00		16.45	SQUARE	5.20
48	398.00	2,910	15.00		8.50	SQUARE	8.80
49	Subtotal General	206,172					
50	Total Plant	3,472,132					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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	-470,907		-470,907	
3					
4	General Regulatory Expenses - Other		987,136	987,136	
5					
6	Regulatory Commission Expenses - Idaho				
7	Other Expenses		10,417	10,417	
8					
9	Oregon Hydro - Fees Amortization	158,506		158,506	
10					
11	Regulatory Commission Expenses - Oregon				
12	General Rate Case		46,064	46,064	
13	Other Expenses		245,009	245,009	
14					
15					
16					
17					
18					
19					
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21					
22					
23					
24					
25					
26					
27					
28					
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36					
37					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL	-312,401	1,288,626	976,225	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	-470,907					2
							3
Electric	928	987,136					4
							5
							6
Electric	928	10,417					7
							8
Electric	928	158,506					9
							10
							11
Electric	928	46,064					12
Electric	928	245,009					13
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							45
		976,225					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	04/18/2007	End of 2006/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $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 Conditioning Cool Credit
4		Irrigation Peak Rewards
5		Energy Star Northwest Homes
6		Oregon Weatherization
7		Residential Retrofit - Cooling
8		Residential Retrofit - Lighting
9		Weatherization Asistance Idaho
10		Building Efficiency Program
11		Commercial Retrofit
12		Oregon School Efficiency
13		Industrial Efficiency
14		Irrigation Efficiency Rewards Program
15		NEEA
16		Distribution Efficiency Initiative
17		Small Project/Education funds
18		DSM Analysis & Accounting
19		
20	(7)	
21	B. 4 Research Support to Others	BPA Energy House Calls
22		BPA Rebate Advantage
23		BPA Residential Education Initative
24		BPA Commercial Education Initiative
25		BPA Other C&RD and CRC
26		
27		
28		
29		
30	Total R, D&D	
31		
32		
33		
34		
35		
36		
37		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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
1,235,476			1,235,476		3
1,324,418			1,324,418		4
469,609			469,609		5
4,126			4,126		6
17,444			17,444		7
298,754			298,754		8
1,455,373			1,455,373		9
374,008			374,008		10
31,819			31,819		11
24,379			24,379		12
1,625,407			1,625,407		13
2,779,620			2,779,620		14
930,455			930,455		15
24,306			24,306		16
3,459			3,459		17
309,685			309,685		18
					19
					20
	336,701		336,701		21
	52,673		52,673		22
	56,727		56,727		23
	4,663		4,663		24
	124,956		124,956		25
					26
					27
					28
					29
10,908,338	575,720		11,484,058		30
					31
					32
					33
					34
					35
					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	11,500,630		
4	Transmission	6,979,846		
5	Regional Market	15,973,997		
6	Distribution	10,164,049		
7	Customer Accounts	4,187,137		
8	Customer Service and Informational			
9	Sales	33,176,001		
10	Administrative and General	81,981,660		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	163,963,320		
12	Maintenance			
13	Production	2,454,601		
14	Transmission	6,617,820		
15	Regional Market	884,361		
16	Distribution	16,362,106		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	26,318,888		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,955,231		
21	Transmission (Enter Total of lines 4 and 14)	13,597,666		
22	Regional Market (Enter Total of Lines 5 and 15)	16,858,358		
23	Distribution (Enter Total of lines 6 and 16)	26,526,155		
24	Customer Accounts (Transcribe from line 7)	4,187,137		
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)	33,176,001		
27	Administrative and General (Enter Total of lines 10 and 17)	81,981,660		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	190,282,208		190,282,208
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	190,282,208		190,282,208
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	40,654,243	3,695,383	44,349,626
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	40,654,243	3,695,383	44,349,626
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):	734,187		734,187
76	TOTAL Plant Removal (Total of lines 73 thru 75)	734,187		734,187
77	Paid Absences	15,977,142		15,977,142
78	Preliminary Survey & Investigation	41,866		41,866
79	Other Accounts	4,473,621		4,473,621
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	20,492,629		20,492,629
96	TOTAL SALARIES AND WAGES	252,163,267	3,695,383	255,858,650

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,634	25	800	1,810	172	376		276	
2	February	2,915	20	900	2,281	182	401		51	
3	March	2,676	15	800	1,824	161	401		290	
4	Total for Quarter 1	8,225			5,915	515	1,178		617	
5	April	2,391	1	1100	1,560	126	376		329	
6	May	3,485	17	1900	2,351	243	376		515	
7	June	4,123	27	1800	3,043	304	376		400	
8	Total for Quarter 2	9,999			6,954	673	1,128		1,244	
9	July	3,820	24	1800	3,084	285	376		75	
10	August	3,626	7	1800	2,912	263	376		75	
11	September	3,318	5	1800	2,557	235	376		150	
12	Total for Quarter 3	10,764			8,553	783	1,128		300	
13	October	2,618	31	800	1,969	173	376		100	
14	November	2,805	29	800	2,226	203	376			
15	December	2,907	1	800	2,337	194	376			
16	Total for Quarter 4	8,330			6,532	570	1,128		100	
17	Total Year to Date/Year	37,318			27,954	2,541	4,562		2,261	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	6,948,258
4	Nuclear	
5	Hydro-Conventional	9,206,526
6	Hydro-Pumped Storage	
7	Other	72,859
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	16,227,643
10	Purchases	4,964,024
11	Power Exchanges:	
12	Received	99,757
13	Delivered	268,856
14	Net Exchanges (Line 12 minus line 13)	-169,099
15	Transmission For Other (Wheeling)	
16	Received	4,483,108
17	Delivered	4,491,181
18	Net Transmission for Other (Line 16 minus line 17)	-8,073
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	21,014,495

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,939,314
23	Requirements Sales for Resale (See instruction 4, page 311.)	108,970
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	5,711,853
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,254,358
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	21,014,495

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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

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	1,833,137	581,968	2,079	25	8 AM
30	February	1,700,010	581,137	2,144	16	8 AM
31	March	1,889,922	750,188	1,946	10	9 AM
32	April	1,888,476	901,443	1,740	6	8 AM
33	May	2,092,719	841,211	2,552	17	7 PM
34	June	2,031,754	575,510	3,050	27	6 PM
35	July	1,930,652	179,104	3,084	24	6 PM
36	August	1,778,926	232,949	2,914	7	6 PM
37	September	1,566,053	352,904	2,578	5	6 PM
38	October	1,383,410	284,088	1,997	31	8 AM
39	November	1,283,111	140,164	2,226	29	8 AM
40	December	1,636,325	291,187	2,318	18	8 AM
41	TOTAL	21,014,495	5,711,853			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.22		
6	Net Peak Demand on Plant - MW (60 minutes)	747			59		
7	Plant Hours Connected to Load	8760			4362		
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	4961791000			241557000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	63198975			13664764		
15	Equipment Costs	391410334			54705143		
16	Asset Retirement Costs	0			0		
17	Total Cost	455103667			68476517		
18	Cost per KW of Installed Capacity (line 17/5) Including	590.6602			1066.2802		
19	Production Expenses: Oper, Supv, & Engr	136088			864657		
20	Fuel	69637027			3429448		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4221854			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	6127655			236070		
27	Rents	187296			8426		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	74915			2439498		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	7691267			0		
32	Maintenance of Electric Plant	2636581			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	4458699			14663		
34	Total Production Expenses	95171382			6992762		
35	Expenses per Net KWh	0.0192			0.0289		
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	2803247	12663	0	145051	801	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9219	140000	0	8359	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	23.617	99.638	0.000	21.752	96.777	0.000
41	Average Cost of Fuel per Unit Burned	23.339	99.574	0.000	21.393	80.269	0.000
42	Average Cost of Fuel Burned per Million BTU	12.660	16.935	0.000	1.280	13.773	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.014	0.000	0.000
44	Average BTU per KWh Net Generation	10432.000	0.000	0.000	10058.000	0.000	0.000

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

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

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

Plant Name: *Valmy* (d)	Plant Name: *Danskin* (e)	Plant Name: *Bennett Mountain* (f)	Line No.
Steam	Gas Turbine	Gas Turbine	1
Outdoor	Conventional	Conventional	2
1981	2001	2005	3
1985	2001	2005	4
283.50	90.00	172.80	5
264	94	192	6
8646	376	329	7
0	100000	163980	8
0	0	0	9
0	0	0	10
0	6	4	11
1744910000	23372000	49343000	12
769351	402745	0	13
53672955	4276833	1012941	14
256370535	47533651	52807282	15
0	0	0	16
310812841	52213229	53820223	17
1096.3416	580.1470	311.4596	18
711761	141783	46418	19
34453372	3355948	4118517	20
0	0	0	21
2885289	0	0	22
0	0	0	23
0	0	0	24
1444277	150923	137818	25
1779274	101088	143723	26
52902	0	0	27
0	0	0	28
11056	0	0	29
408848	94791	77024	30
7686202	52638	22178	31
1797301	252430	101399	32
102255	0	0	33
51332537	4149601	4647077	34
0.0294	0.1775	0.0942	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
851079	5769	0	332425	0	0	468929	0	0	38
9777	138778	0	1035	0	0	1038	0	0	39
38.185	101.561	0.000	10.095	0.000	0.000	8.783	0.000	0.000	40
37.481	100.466	0.000	10.095	0.000	0.000	8.783	0.000	0.000	41
1.901	17.237	0.000	9.726	0.000	0.000	8.461	0.000	0.000	42
0.020	0.000	0.000	0.144	0.000	0.000	0.083	0.000	0.000	43
9634.000	0.000	0.000	14764.000	0.000	0.000	9865.000	0.000	0.000	44

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/18/2007	2006/Q4

FOOTNOTE DATA

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	04/18/2007	End of 2006/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)	109	76
7	Plant Hours Connect to Load	7,973	8,735
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	5
12	Net Generation, Exclusive of Plant Use - Kwh	349,840,000	372,214,000
13	Cost of Plant		
14	Land and Land Rights	875,318	676,645
15	Structures and Improvements	11,857,401	666,848
16	Reservoirs, Dams, and Waterways	4,242,904	7,480,784
17	Equipment Costs	31,110,315	6,827,455
18	Roads, Railroads, and Bridges	306,333	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	48,392,271	16,138,209
21	Cost per KW of Installed Capacity (line 20 / 5)	524.2933	215.1761
22	Production Expenses		
23	Operation Supervision and Engineering	175,674	605,398
24	Water for Power	2,064,072	237,349
25	Hydraulic Expenses	152,208	560,962
26	Electric Expenses	41,186	33,765
27	Misc Hydraulic Power Generation Expenses	224,081	134,188
28	Rents	146	2,830
29	Maintenance Supervision and Engineering	99,464	105,550
30	Maintenance of Structures	96,801	52,872
31	Maintenance of Reservoirs, Dams, and Waterways	2,545	23,948
32	Maintenance of Electric Plant	204,262	193,411
33	Maintenance of Misc Hydraulic Plant	81,851	206,273
34	Total Production Expenses (total 23 thru 33)	3,142,290	2,156,546
35	Expenses per net KWh	0.0090	0.0058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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
745	14	218	6
8,760	8,758	8,760	7
			8
728	14	220	9
220	1	202	10
7	2	6	11
2,926,140,000	56,406,000	1,238,175,000	12
			13
12,545,447	82,142	866,939	14
30,069,955	7,364,154	9,830,938	15
66,871,141	3,145,630	30,375,714	16
51,669,986	12,426,390	14,832,256	17
518,444	122,668	565,842	18
0	0	0	19
161,674,973	23,140,984	56,471,689	20
276.1786	1,863.2032	297.2194	21
			22
486,181	122,489	253,942	23
139,680	64,864	67,314	24
448,182	151,833	233,083	25
355,284	81,536	212,036	26
336,157	133,863	193,327	27
228,395	105	38,122	28
360,368	62,143	242,395	29
200,492	6,854	314,054	30
384,516	1,598	28,345	31
285,759	100,570	151,880	32
763,373	74,902	312,430	33
3,988,387	800,757	2,046,928	34
0.0014	0.0142	0.0017	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	04/18/2007	End of 2006/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)	443	28
7	Plant Hours Connect to Load	8,751	8,752
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	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,548,078,000	172,947,000
13	Cost of Plant		
14	Land and Land Rights	1,558,955	205,376
15	Structures and Improvements	2,403,495	2,516,767
16	Reservoirs, Dams, and Waterways	52,665,106	3,371,066
17	Equipment Costs	15,082,679	3,211,940
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	72,529,427	9,609,832
21	Cost per KW of Installed Capacity (line 20 / 5)	185.2603	441.4254
22	Production Expenses		
23	Operation Supervision and Engineering	232,138	104,822
24	Water for Power	64,831	438,550
25	Hydraulic Expenses	208,063	133,282
26	Electric Expenses	128,515	64,431
27	Misc Hydraulic Power Generation Expenses	185,916	55,291
28	Rents	63,689	0
29	Maintenance Supervision and Engineering	205,759	51,987
30	Maintenance of Structures	31,898	10,898
31	Maintenance of Reservoirs, Dams, and Waterways	132,191	6,363
32	Maintenance of Electric Plant	205,347	45,306
33	Maintenance of Misc Hydraulic Plant	519,781	97,891
34	Total Production Expenses (total 23 thru 33)	1,978,128	1,008,821
35	Expenses per net KWh	0.0008	0.0058

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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
91	24	52	6
8,760	8,748	8,755	7
			8
89	26	54	9
84	14	50	10
7	4	5	11
482,845,000	133,516,000	150,325,000	12
			13
3,505,508	51,675	255,499	14
2,789,969	25,223,736	10,808,047	15
9,764,916	13,641,459	7,932,716	16
7,364,871	30,376,612	20,494,470	17
238,871	835,946	1,917,603	18
0	0	0	19
23,664,135	70,129,428	41,408,335	20
285.7987	2,805.1771	785.1410	21
			22
859,171	199,490	189,378	23
245,377	48,011	48,499	24
1,364,137	144,657	154,510	25
31,275	35,037	43,657	26
324,413	113,466	137,524	27
64,884	7,539	1,056	28
161,741	96,246	36,016	29
67,286	61,551	55,153	30
133,527	83,310	17,557	31
103,892	178,315	32,861	32
368,813	141,340	78,233	33
3,724,516	1,108,962	794,444	34
0.0077	0.0083	0.0053	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	04/18/2007	End of 2006/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	13
7	Plant Hours Connect to Load	8,753	8,760
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	215,141,000	98,994,000
13	Cost of Plant		
14	Land and Land Rights	172,970	311,407
15	Structures and Improvements	1,538,577	1,139,956
16	Reservoirs, Dams, and Waterways	4,642,118	512,402
17	Equipment Costs	6,563,186	2,221,828
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	12,946,210	4,236,976
21	Cost per KW of Installed Capacity (line 20 / 5)	375.2525	338.9581
22	Production Expenses		
23	Operation Supervision and Engineering	338,582	104,765
24	Water for Power	58,558	28,778
25	Hydraulic Expenses	314,032	100,925
26	Electric Expenses	18,513	23,950
27	Misc Hydraulic Power Generation Expenses	150,366	66,012
28	Rents	0	28
29	Maintenance Supervision and Engineering	139,433	62,540
30	Maintenance of Structures	69,305	42,214
31	Maintenance of Reservoirs, Dams, and Waterways	67,754	1,956
32	Maintenance of Electric Plant	206,376	34,938
33	Maintenance of Misc Hydraulic Plant	161,528	58,309
34	Total Production Expenses (total 23 thru 33)	1,524,447	524,415
35	Expenses per net KWh	0.0071	0.0053

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	0	58	6
0	0	7,748	7
			8
0	70	59	9
0	63	1	10
0	8	1	11
0	256,817,000	138,982,000	12
			13
114,367	403,335	138,100	14
15,744,184	888,303	10,326,813	15
13,556,785	6,602,823	17,147,050	16
1,155,344	6,493,114	27,574,118	17
99,051	88,693	501,876	18
0	0	0	19
30,669,731	14,476,268	55,687,957	20
0.0000	241.2711	936.7192	21
			22
0	748,221	106,566	23
0	94,332	1,337,830	24
3,774,092	406,261	72,529	25
0	155,398	46,156	26
0	193,365	141,358	27
0	1,235	1,461	28
0	177,235	36,436	29
0	97,293	38,311	30
0	15,843	5,013	31
0	256,010	69,660	32
78,072	153,733	61,093	33
3,852,164	2,298,926	1,916,413	34
0.0000	0.0090	0.0138	35

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

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

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

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

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

Upstream storage in Brownlee Reservoir.

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	2.4	15,691,000	1,734,386
3	Thousand Springs	1912	8.80	12.1	50,415,000	4,697,635
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.0	144	901,055
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9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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
693,754	55,824		78,860			2
533,822	113,423		171,934			3
						4
						5
						6
180,211				Diesel		7
						8
						9
						10
						11
						12
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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) 04/18/2007	Year/Period of Report End of 2006/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	85.17		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	226.17		1
5	State Line	Midpoint	345.00	345.00	S Tower	76.08		2
6	Kinport	Borah	345.00	345.00	S Tower	27.31		1
7	Midpoint	Borah #1	345.00	345.00	H Wood	79.38		1
8	Midpoint	Borah #2	345.00	345.00	H Wood	77.59		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	0.60		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	72.72		1
18	Mora	Bowmont	138.00	230.00	S P Wood	9.86		1
19	Mora	Bowmont	138.00	230.00	H Wood	10.77		1
20	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
21	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
22	Boise Bench	Caldwell	230.00	230.00	S Tower	7.52		1
23	Boise Bench	Caldwell	230.00	230.00	H Wood	33.53		1
24	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.99		2
25	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
26	Brownlee 714	Oxbow	230.00	230.00	SP Steel	10.80		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.11		1
28	Caldwell	Ontario	230.00	230.00	S Tower	3.31		1
29	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.48		1
30	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
31	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.11		1
32	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
33	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.71		1
34	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.99		2
35	Oxbow	Brownlee	230.00	230.00	S Tower	10.23		2
36					TOTAL	4,570.73	11.02	160

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,740,147	16,223,456					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	5,438,624	5,721,767					7
715.5 ACSR	64,851	6,045,455	6,110,306					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,310,541	2,361,955					11
715.5 ACSR	9,145	998,452	1,007,597					12
1272 ACSR	108,301	2,536,324	2,644,625					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	8,755,911	10,894,147					21
1272 ACSR	1,133,957	5,695,395	6,829,352					22
715.5 ACSR								23
1272 ACSR	2,999,026	6,534,851	9,533,877					24
795 AAC		80,895	80,895					25
954 ACSR	34,174	16,026,470	16,060,644					26
2X954 ACSR	194,763	5,902,042	6,096,805					27
1272 ACSR								28
1272 ACSR	81,701	1,666,354	1,748,055					29
715.5 ACSR	336,186	3,722,502	4,058,688					30
715.5 ACSR								31
795 ACSR	53,068	1,795,462	1,848,530					32
795 ACSR								33
VARIOUS	269,411	7,991,043	8,260,454					34
1272 ACSR	6,033	1,182,550	1,188,583					35
	26,600,568	295,621,093	322,221,661	7,163,918	2,749,697	1,120,664	11,034,279	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
2	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.51		1
3	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.20		2
4	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
5	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
6	Brownlee	Boise Bench	230.00	230.00	S Tower	102.30		2
7	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.34		1
8	Palette Jct	Enterprise	230.00	230.00	H Wood	29.08		1
9	Borah	Brady #2	230.00	230.00	S Tower	0.43		1
10	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
11	Borah	Brady #1	230.00	230.00	H Wood	3.97		1
12								
13	Goshen	State Line	161.00	161.00	H Wood	90.50		1
14	Don	Goshen	161.00	161.00	S Tower	2.39		2
15	Don	Goshen	161.00	161.00	H Wood	46.19		2
16								
17	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	9.84		2
18	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	2.58		2
19	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.11		2
20	Nampa	Caldwell	138.00	138.00	S P Wood	9.73		2
21	Upper Salmon	Mountain Home Jct		138.00	H Wood	4.31		1
22	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	49.32		1
23	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
24	Eastgate	Russet	138.00	138.00	S P Wood	2.07		1
25	Brady	Fremont	138.00	138.00	S Tower	1.00		2
26	Brady	Fremont	138.00	138.00	H Wood	24.32		2
27	Brady	Fremont	138.00	138.00	S P Wood	24.35		2
28	King	Lower Malad	138.00	138.00	H Wood	84.91		2
29	Emmett Jct	Payette	138.00	138.00	H Wood	62.79		2
30	Mountain Home AFB Tap		138.00	138.00	H Wood	6.21		1
31	Ontario	Quartz	138.00	138.00	H Wood	73.41		1
32	King	American Falls PP	138.00	138.00	S Tower	1.03		2
33	King	American Falls PP	138.00	138.00	H Wood	146.40		1
34	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
35	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
36					TOTAL	4,570.73	11.02	160

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 ACSR	227,825	5,654,772	5,882,597					1
VARIOUS								2
1272 ACSR	23,308	2,075,638	2,098,946					3
1272 ACSR	138,477	1,233,942	1,372,419					4
1272 ACSR	10,737	1,252,130	1,262,867					5
954 ACSR	170,694	5,620,492	5,791,186					6
715.5 ACSR	247,857	4,875,963	5,123,820					7
1272 ACSR	51,122	1,631,895	1,683,017					8
1272 ACSR	3,068	226,250	229,318					9
715.5 ACSR								10
1272 ACSR	10,064	180,008	190,072					11
								12
250 COPPER	16,155	648,382	664,537					13
715.5 ACSR	76,041	1,622,852	1,698,893					14
397.5 ACSR								15
								16
250 COPPER	26,507	2,346,862	2,373,369					17
250 COPPER								18
715.5 ACSR	15,088	249,232	264,320					19
795 AAC	157,432	1,794,059	1,951,491					20
795 ACSR	47,687	1,696,746	1,744,433					21
VARIOUS								22
795 ACSR	43,568	764,183	807,751					23
795 AAC	270,823	557,504	828,327					24
VARIOUS	564,932	3,542,654	4,107,586					25
VARIOUS								26
VARIOUS								27
VARIOUS	76,823	1,398,534	1,475,357					28
VARIOUS	30,918	1,327,120	1,358,038					29
397.5 ACSR	1,955		1,955					30
VARIOUS	34,428	1,502,877	1,537,305					31
715.5 ACSR	148,914	4,550,548	4,699,462					32
715.5 ACSR								33
715.5 ACSR								34
4\0	4,191	309,827	314,018					35
	26,600,568	295,621,093	322,221,661	7,163,918	2,749,697	1,120,664	11,034,279	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
2	Upper Salmon A-B	King	138.00	138.00	H Wood	5.88		1
3	Upper Salmon B	Wells	138.00	138.00	H Wood	125.61		1
4	King	Wood River	138.00	138.00	H Wood	73.57		1
5	Boise Bench	Grove	138.00	138.00	S P Wood	10.47		2
6	Quartz	John Day	138.00	138.00	H Wood	67.31		1
7	Sinker Creek Tap		138.00	138.00	H Wood	2.83		1
8	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
9	Mora	Cloverdale	138.00	138.00	S P Wood	22.37		1
10	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
11	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
12	Wood River	Midpoint	138.00	138.00	H Wood	53.06		2
13	Wood River	Midpoint	138.00	138.00	S P Wood	16.74		2
14	Oxbow	McCall	138.00	138.00	H Wood	38.47		1
15	Oxbow	McCall	138.00	138.00	S P Wood	1.65		1
16	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.52		2
17	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
18	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.47		1
19	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.41		2
20	Pingree	Haven	138.00	138.00	S P Wood	11.75		1
21	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.21		2
22	Twin Falls	Russett	138.00	138.00	S P Wood	1.73		1
23	Blackfoot	Aiken	138.00	138.00	S P Wood	6.17		2
24	Peterson	Tendoy	138.00	138.00	H Wood	57.26		1
25	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.32		1
26	Boise Bench	Mora	138.00	138.00	H Wood	13.14		2
27	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
28	Gary Lane	Eagle	138.00	138.00	S P Wood	6.44		1
29	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.92	2.98	1
30	Boise Bench	Butler	138.00	138.00	S P Wood	0.08	4.02	1
31	Eagle	Star		138.00	S P Wood	6.35		1
32	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.09		1
33	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.24	4.02	1
34	Butler	Wye	138.00	138.00	S P Steel	2.86		1
35	Horseflat	Starkey	138.00	138.00	S P Steel			1
36					TOTAL	4,570.73	11.02	160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR		96,921	96,921					1
250 COPPER	2,741	93,073	95,814					2
VARIOUS	28,490	1,745,804	1,774,294					3
VARIOUS	173,683	2,355,148	2,528,831					4
VARIOUS	225,602	1,629,593	1,855,195					5
397.5 ACSR	92,173	2,362,416	2,454,589					6
VARIOUS	20	77,199	77,219					7
715.5 ACSR	1,736,227	5,433,147	7,169,374					8
VARIOUS								9
1272 ACSR								10
250 COPPER	450	63,439	63,889					11
397.5 ACSR	281,064	6,374,306	6,655,370					12
397.5 ACSR								13
397.5 ACSR	84,183	1,752,478	1,836,661					14
397.5 ACSR								15
715.5 ACSR	211,131	1,445,893	1,657,024					16
715.5 ACSR	3,324	1,088,540	1,091,864					17
397.5 ACSR	14,927	587,404	602,331					18
715.5 ACSR	13,734	1,052,549	1,066,283					19
397.5 ACSR	11,213	778,092	789,305					20
VARIOUS	54,848	2,958,765	3,013,613					21
715.5 ACSR	16,790	206,158	222,948					22
715.5 ACSR	13,616	456,919	470,535					23
397.5 ACSR	395,696	3,449,949	3,845,645					24
715.5 ACSR	45,989	1,054,909	1,100,898					25
715.5 ACSR	14,697	632,718	647,415					26
795 AAC		49,642	49,642					27
795 AAC	489,037	1,957,948	2,446,985					28
1272 ACSR	935,725	2,884,136	3,819,861					29
1272 ACSR	34,687	838,605	873,292					30
715.5 ACSR		2,909,433	2,909,433					31
795 AAC	43,035	443,805	486,840					32
1272 ACSR	140,412	709,148	849,560					33
795 ACSR	134,471	1,405,436	1,539,907					34
954 ACSR	416,925	64,546	481,471					35
	26,600,568	295,621,093	322,221,661	7,163,918	2,749,697	1,120,664	11,034,279	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.86		1
2	Caldwell	Willis	138.00	138.00	S P Steel	1.31		1
3	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
4	Caldwell	Willis	138.00	138.00	S P Wood	0.82		1
5	Valivue Tap		138.00	138.00	S P Steel	0.82		2
6	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
7	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
8	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
9	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
10	C J Strike	Strike Jct	138.00	138.00	S Tower	4.31		2
11	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.55		1
12								
13	Strike Jct	Bowmont		138.00	H Wood	0.05		1
14	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
15	Strike Jct	Bowmont	138.00	138.00	H Wood	68.14		1
16	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.43		2
17	Bliss	King	138.00	138.00	H Wood	10.44		1
18	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
19	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
20								
21								
22								
23	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
24								
25								
26	69 Kv Lines		69.00	69.00	H Wood	166.31		1
27	69 Kv Lines		69.00	69.00	S P Wood	958.43		1
28								
29								
30	46 Kv Lines		46.00	46.00	S P Wood	411.39		1
31								
32								
33								
34								
35								
36					TOTAL	4,570.73	11.02	160

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR		100,161	100,161					1
1272 ACSR	168,225	2,140,418	2,308,643					2
795 ACSR								3
795 ACSR								4
795 ACSR		351,497	351,497					5
715.5 ACSR	1,174	212,777	213,951					6
250 COPPER	58	53,888	53,946					7
715.5 ACSR		76,560	76,560					8
397.5 ACSR		4,406	4,406					9
715.5 ACSR	1,074	253,872	254,946					10
397.5 ACSR	4,355	524,571	528,926					11
								12
715.5 ACSR	29,902	1,689,967	1,719,869					13
715.5 ACSR								14
								15
715.5 ACSR	7	279,481	279,488					16
715.5 ACSR	5,620	964,435	970,055					17
715.5 ACSR	2,814	183,606	186,420					18
397.5 ACSR	12,885	261,511	274,396					19
								20
								21
								22
397.5 ACSR	1,978	63,404	65,382					23
								24
								25
VARIOUS	928,990	32,944,846	33,873,836					26
VARIOUS								27
								28
								29
VARIOUS	176,265	7,976,960	8,153,225					30
								31
	5,736,253		5,736,253					32
								33
				7,163,918	2,749,697	1,120,664	11,034,279	34
								35
	26,600,568	295,621,093	322,221,661	7,163,918	2,749,697	1,120,664	11,034,279	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Horse Flat	Starkey	0.10	SP Steel	1.00	1	1
2	Caldwell	Willis	3.72	SP Steel	19.00	1	1
3				SP Steel	19.00	1	1
4				SP Wood	19.00	1	1
5							
6	Cloverdale	Blackcat	5.94	SP Wood	18.00	1	1
7	Nampa Tap		3.32	SP Steel	12.00	1	2
8							
9							
10							
11							
12							
13							
14							
15							
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43							
44	TOTAL		13.08		88.00	6	7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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 KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
954	ACSR	Vert 6'	138	416,925	64,546			481,471	1
1272	ACSR	Vert 6'	138	168,225	1,387,779	752,638		2,308,642	2
795	AAC	TVS 7'	138						3
795	AAC	TVS 7'	138						4
									5
795	ACSR	TVS 7'	138	118,359	426,956	185,324		730,639	6
1272	ACSR	Vert 12'	230	317,306	2,504,853	432,654		3,254,813	7
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				1,020,815	4,384,134	1,370,616		6,775,565	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	04/18/2007	End of 2006/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	Bennett Mountain Power Plant	transmission	230.00	18.00	
10	Bennett Mountain Power Plant	transmission	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	12.50	
14	Blackfoot	distribution	138.00	38.00	13.80
15	Bliss - attended	transmission	138.00	13.80	
16	Blue Gulch	distribution	138.00	34.50	
17	Boise Bench - attended	distribution	138.00	34.50	
18	Boise Bench - attended	transmission	138.00	69.00	13.80
19	Boise Bench - attended	transmission	230.00	138.00	13.80
20	Boise	distribution	138.00	13.00	
21	Borah	transmission	345.00	230.00	13.80
22	Bowmont	distribution	69.00	46.00	6.90
23	Bowmont	distribution	138.00	34.50	
24	Bowmont	distribution	138.00	69.00	13.80
25	Brady	transmission	46.00	12.50	
26	Brady	transmission	230.00	138.00	13.80
27	Brownlee - attended	transmission	230.00	13.80	
28	Bruneau Bridge	distribution	138.00	34.50	
29	Buckhorn	distribution	69.00	35.00	
30	Bucyrus	distribution	46.00	7.20	
31	Buhl	distribution	46.00	13.00	
32	Burley Rural	distribution	69.00	13.00	
33	Butler	distribution	138.00	13.00	
34	Caldwell	distribution	138.00	13.00	
35	Caldwell	distribution	138.00	69.00	13.00
36	Caldwell	transmission	230.00	138.00	12.50
37	Canyon Creek	distribution	138.00	34.50	
38	Canyon Creek	distribution	138.00	69.00	12.50
39	Cascade Power Plant - attended	transmission	69.00	4.60	
40	Cascade	Distribution	69.00	13.10	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
130	3	1				14
69	3					15
15	1					16
42	2					17
75	3					18
374	3					19
67	3					20
450	3	1				21
8	3					22
18	1					23
25	1					24
		6				25
300	3					26
734	5	1				27
30	2					28
20	1					29
6	1	3				30
20	2					31
12	1					32
48	2					33
39	2	1				34
50	2					35
240	2					36
15	1					37
		1				38
12	1					39
10	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	04/18/2007	End of 2006/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	Chestnut	distribution	138.00	13.00	
2	Clear Lake - attended	transmission	46.00	2.30	
3	Cliff	transmission	138.00	46.00	12.50
4	Cloverdale	transmission	138.00	13.00	
5	Cloverdale	transmission	138.00	69.00	12.50
6	Dale	distribution	69.00	13.00	
7	Dale	distribution	138.00	34.50	
8	Dale	distribution	138.00	46.00	12.50
9	Danskin	transmission	138.00	12.00	
10	Don	distribution	138.00	7.60	
11	Don	distribution	138.00	13.20	
12	Don	distribution	138.00	13.00	
13	DRAM	distribution	138.00	13.00	
14	DRAM	distribution	230.00	138.00	13.80
15	Duffin	distribution	138.00	34.50	
16	Eagle	distribution	138.00	13.00	
17	Eastgate	distribution	138.00	13.00	
18	Eckert	distribution	138.00	36.20	
19	Eden	distribution	138.00	34.50	
20	Eden	distribution	138.00	46.00	12.50
21	Elkhorn	distribution	138.00	12.00	
22	Elmore	transmission	138.00	34.50	
23	Elmore	distribution	138.00	69.00	12.50
24	Emmett	distribution	138.00	12.50	
25	Emmett	distribution	138.00	69.00	12.50
26	Falls	distribution	46.00	12.50	
27	Filer	distribution	46.00	12.50	
28	Flying H	distribution	69.00	2.40	
29	Fort Hall	distribution	46.00	12.50	
30	Fossil Gulch	distribution	138.00	13.80	4.60
31	Fossil Gulch	distribution	138.00	34.50	
32	Fremont	transmission	138.00	46.00	12.50
33	Gary	distribution	138.00	13.00	
34	Gem	distribution	69.00	13.00	
35	Golden Valley	distribution	69.00	12.50	
36	Gowen Substation	distribution	138.00	35.00	
37	Grindstone	distribution	35.00	12.50	
38	Grove	distribution	138.00	12.50	
39	Hageman	distribution	46.00	12.50	
40	Hailey	distribution	138.00	12.50	

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	04/18/2007	End of 2006/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
48	2					1
4	1					2
16	3	1				3
48	2					4
25	1					5
		1				6
27	1					7
25	1					8
96	2					9
		1				10
38	3	12				11
26	1	1				12
134	8					13
160	2					14
36	2					15
38	2					16
36	2					17
18	1					18
24	1					19
15	1					20
15	2					21
17	1					22
30	2					23
15	1					24
25	1					25
17	2					26
10	1	1				27
15	2					28
10	1					29
8	1					30
15	1					31
50	3	1				32
36	2					33
17	2					34
10	1	1				35
24	1					36
10	2					37
72	3					38
12	2					39
20	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	04/18/2007	End of 2006/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	Haven	distribution	46.00	34.50	
2	Hewlett Packard	distribution	138.00	13.10	
3	Hidden Springs	distribution	138.00	13.09	
4	Highland	distribution	138.00	13.09	
5	Hill	distribution	138.00	12.50	
6	Homedale	distribution	69.00	12.50	
7	Horse Flat	transmission	230.00	138.00	13.80
8	Horseshoe Bend	distribution	35.00	12.50	
9	Horseshoe Bend	distribution	69.00	36.20	
10	Horseshoe Bend	distribution	69.00	25.00	
11	Houston	distribution	69.00	13.00	
12	Hulen	distribution	46.00	13.00	
13	Hunt	transmission	230.00	138.00	13.80
14	Hydra	distribution	138.00	34.50	
15	Island	distribution	69.00	12.50	
16	Jerome	distribution	138.00	12.50	
17	Julion Clawson	distribution	138.00	34.50	
18	Joplin	distribution	138.00	13.00	
19	Karcher	distribution	138.00	13.09	
20	Kenyon	distribution	69.00	12.50	
21	Ketchum	distribution	138.00	12.50	
22	Kinport	transmission	161.00	46.00	13.00
23	Kinport	transmission	230.00	138.00	12.50
24	Kinport	transmission	230.00	138.00	13.80
25	Kinport	transmission	345.00	230.00	13.80
26	Kramer	distribution	138.00	34.50	
27	Kramer	distribution	138.00	13.00	
28	Kuna	distribution	138.00	13.00	
29	Lake Fork	distribution	138.00	36.20	
30	Lake Fork	transmission	138.00	69.00	12.50
31	Lamb	distribution	138.00	13.09	
32	Lansing	distribution	69.00	13.00	
33	Lincoln	distribution	138.00	13.00	
34	Linden	distribution	138.00	13.00	
35	Locust	distribution	138.00	34.50	
36	Locust	transmission	230.00	138.00	13.00
37	Lower Malad - attended	transmission	138.00	7.20	
38	Lower Salmon - attended	transmission	138.00	13.80	
39	Map Rock	distribution	69.00	12.50	
40	McCall	distribution	69.00	12.50	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
12	1					1
20	1					2
8	1					3
18	1					4
24	1					5
20	2					6
100	1					7
5	1					8
12	1					9
5	1					10
10	1					11
10	1	1				12
300	3					13
24	1					14
12	1					15
20	1					16
30	2					17
15	1					18
12	1					19
20	2					20
42	2					21
		7				22
180	1					23
180	1					24
600	3	1				25
12	1					26
18	1					27
15	1					28
18	1					29
15	1					30
18	1					31
12	1					32
11	1					33
33	2					34
48	2					35
360	2					36
15	1					37
70	4					38
10	1					39
8	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	04/18/2007	End of 2006/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	McCall	distribution	138.00	35.00	
2	McCall	distribution	138.00	69.00	12.50
3	Meridian	distribution	138.00	13.00	
4	Micron	distribution	138.00	12.50	
5	Midpoint	transmission	230.00	138.00	12.50
6	Midpoint	transmission	345.00	230.00	13.80
7	Midpoint	transmission	500.00	345.00	
8	Midrose	distribution	138.00	13.09	
9	Milner	distribution	69.00	38.00	13.80
10	Milner	distribution	69.00	38.00	7.20
11	Milner	distribution	138.00	34.50	
12	Milner PP - attended	transmission	138.00	13.80	
13	Moonstone	distribution	138.00	34.50	
14	Mora	distribution	138.00	34.50	
15	Moreland	distribution	46.00	12.50	
16	Moreland	distribution	46.00	34.50	12.50
17	Mountain Home	distribution	69.00	12.50	
18	Mountain Home Air Force Base	distribution	69.00	12.50	
19	Mountain Home Air Force Base	distribution	138.00	12.50	
20	Nampa	distribution	230.00	138.00	13.80
21	Nampa	distribution	138.00	12.50	
22	Nampa	distribution	138.00	69.00	12.50
23	New Meadows	distribution	69.00	35.00	
24	New Plymouth	distribution	69.00	12.50	
25	Notch Butte	distribution	13.00	7.56	
26	Parma	distribution	69.00	12.50	
27	Parma	distribution	69.00	34.50	
28	Paul	distribution	138.00	34.50	12.50
29	Payette	distribution	138.00	12.50	
30	Pingree	distribution	138.00	46.00	12.50
31	Pingree	distribution	138.00	36.00	
32	Pleasant Valley	distribution	138.00	34.50	
33	Pocatello	distribution	46.00	12.50	
34	Portneuf	distribution	138.00	36.20	
35	Portneuf	distribution	46.00	35.00	
36	Rockford	distribution	46.00	12.50	
37	Russett	distribution	138.00	12.50	
38	Sailor Creek	distribution	138.00	13.80	4.60
39	Sailor Creek	distribution	138.00	34.50	
40	Salmon	distribution	69.00	12.50	

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	04/18/2007	End of 2006/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.
18	1					1
30	1					2
36	2					3
48	4					4
120	1					5
720	2					6
750	3	1				7
18	1					8
75	3	1				9
8	3	1				10
16	1					11
36	1					12
12	1					13
33	2					14
8	1					15
10	3	1				16
12	1					17
		1				18
18	1					19
180	1					20
50	3					21
25	1					22
10	4					23
10	1					24
11	1					25
10	1					26
12	1					27
36	2					28
22	3					29
50	3					30
22	2					31
42	2					32
36	2					33
18	1					34
5	3	1				35
14	2					36
18	1					37
15	2					38
15	1					39
10	1	4				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2007	End of 2006/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	Salmon	distribution	69.00	34.50	12.50
2	Shoshone	distribution	46.00	13.00	
3	Shoshone	distribution	46.00	7.20	
4	Shoshone Falls - attended	transmission	46.00	2.30	
5	Shoshone Falls - attended	transmission	46.00	6.60	
6	Silver	distribution	138.00	34.50	
7	Simplot	distribution	138.00	12.50	
8	Sinker Creek	distribution	138.00	34.50	
9	Siphon	distribution	138.00	34.50	
10	South Park	distribution	46.00	13.00	
11	Star	distribution	138.00	13.00	
12	Starley	Transmission	138.00	69.00	12.50
13	State	distribution	69.00	12.50	
14	Stoddard	distribution	138.00	13.00	
15	Strike Power Plant - attended	transmission	138.00	13.80	
16	Sugar	distribution	138.00	34.50	
17	Swan Falls - attended	transmission	138.00	6.90	
18	Taber	distribution	46.00	12.50	
19	Ten Mile	distribution	138.00	13.09	
20	Terry	distribution	138.00	12.50	
21	Thousand Springs - attended	transmission	46.00	6.90	
22	Thousand Springs - attended	transmission	7.00	2.40	
23	Toponis	distribution	138.00	34.50	
24	Twin Falls	distribution	138.00	13.00	
25	Twin Falls	distribution	138.00	46.00	12.50
26	Twin Falls PP - attended	transmission	138.00	7.20	
27	Twin Falls PP - attended	transmission	138.00	13.20	
28	Upper Malad - attended	transmission	46.00	7.20	
29	Upper Salmon- attended	transmission	138.00	7.20	
30	Ustick	distribution	138.00	12.50	
31	Vallivue	distribution	138.00	13.09	
32	Victory	distribution	138.00	12.50	
33	Ware	distribution	69.00	12.50	
34	Weiser	distribution	69.00	12.50	
35	Weiser	distribution	138.00	69.00	12.50
36	Wilder	distribution	69.00	13.00	
37	Willis	distribution	138.00	13.09	
38	Wye	distribution	138.00	13.00	
39	Zilog	distribution	138.00	13.09	
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2007	Year/Period of Report End of 2006/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.
10	3	1				1
10	1	1				2
2	3					3
3	1					4
10	1					5
12	1					6
15	1					7
12	1					8
33	2					9
10	1					10
18	1					11
18	1					12
33	2					13
15	1					14
83	3					15
20	2					16
18	1					17
5	1					18
18	1					19
42	3					20
8	1					21
2	1					22
18	1					23
40	2					24
33	2					25
9	1					26
72	1					27
8	1					28
36	4					29
44	2					30
18	1					31
24	1					32
12	1					33
20	2					34
25	1					35
10	1					36
18	1					37
56	3					38
24	1					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	04/18/2007	End of 2006/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2	The above are all State of Idaho				
3					
4	Montana:				
5	Peterson	transmission	230.00	69.00	13.20
6					
7	Nevada:				
8	Valmy - attended	transmission	345.00	21.30	
9	Wells	transmission	138.00	69.00	12.50
10					
11	Oregon:				
12	Boardman - attended	transmission	500.00	24.00	
13	Cairo	distribution	69.00	12.50	
14	Hells Canyon - attended	transmission	230.00	13.80	
15	Hines	transmission	138.00	115.00	12.50
16	Malheur Butte	distribution	69.00	34.50	12.50
17	Nyssa	distribution	69.00	12.50	
18	Ontario	distribution	138.00	12.50	
19	Ontario	distribution	138.00	69.00	12.50
20	Ontario	distribution	230.00	138.00	12.50
21	Ore-Ida	distribution	69.00	12.50	
22	Oxbow - attended	transmission	69.00	38.00	12.50
23	Oxbow - attended	transmission	230.00	13.80	
24	Oxbow - attended	transmission	230.00	138.00	13.80
25	Quartz	transmission	138.00	69.00	12.50
26	Quartz	transmission	230.00	138.00	13.00
27	Vale	distribution	69.00	13.09	
28					
29	Wyoming:				
30	Jim Bridger - attended	transmission	345.00	22.00	
31					
32					
33					
34					
35					
36					
37	Transformers-distribution substations under 10,000				
38	KVA 89 unattended.				
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	04/18/2007	End of 2006/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
						2
						3
						4
30	3	1				5
						6
						7
150	1					8
26	4					9
						10
						11
55	1					12
12	1					13
500	3	1				14
40	1					15
10	3					16
20	2					17
38	2					18
65	3					19
240	2					20
15	1					21
10	3	1				22
244	2					23
100	1					24
30	2					25
100	3	1				26
10	1					27
						28
						29
748	1					30
						31
						32
						33
						34
						35
						36
						37
354						38
						39
						40

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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	$ 876,469,532	$ 802,914,413
3	Operating Expenses			
4	Operation Expenses (401)	15	532,371,073	474,244,701
5	Maintenance Expenses (402)	15	60,277,132	55,287,956
6	Depreciation Expense (403)		84,214,083	85,895,690
7	Amort. & Depl. of Utility Plant (404-405)		587,822	6,781,326
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Regulatory Study Costs (407)			
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits/Credits (407.3 & 407.4)		10,391,374	11,370,700
13	Taxes Other Than Income Taxes (408.1)	2	16,840,362	18,828,248
14	Income Taxes - Federal (409.1)	2	51,553,061	67,059,990
15	- Other (409.1)	2	5,093,547	9,235,170
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	(8,706,428)	(35,537,390)
17	Investment Tax Credit Adj. - Net (411.4)	2	320,531	2,016,462
18	(Less) Gains from Disp. of Utility Plant (411.6)			
19	Losses from Disp. of Utility Plant (411.7)			
20	(Less) Gains from Disposition of Allowances (411.8)			
21	Losses from Disposition of Allowances (411.9)			
22				
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		752,942,558	695,182,852
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 123,526,975	$ 107,731,561

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 9,243,878
FUTA	109,818
State Unemployment	262,407
Payroll Deduction & Loading	(9,613,531)
Total Labor Related	2,573
Property Taxes	13,196,881
Kilowatt-hour Tax	1,722,950
Licenses	3,213
Regulatory Commission Fees	1,682,342
Irrigation PIC	232,404
Total Taxes Other Than Income Taxes	16,840,362
Federal Income Taxes	51,553,061
State Income Taxes	5,093,547
Deferred Income Taxes	(8,706,428)
Investment Tax Credit Adjustment - Net	320,531
Total Taxes Allocated to Idaho	$ 65,101,073

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)	$ 10,522,187	$ 6,717,530
2	Customer Accounts Receivable (Account 142)	49,830,007	$ 54,218,159
3	Other Accounts Receivable (Account 143)	6,860,636	$ 10,081,728
4	(Disclose any capital stock subscription received)		
5	Total		
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	833,238	968,073
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ (833,238)	$ (968,073)
12			
13			
14	Notes Receivable - Account 141: (at 12-31-06)		
15	Directors, officers, and employees - $ 4,979,158		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-06)		
19	Directors, officers, and employees - $ 3,336		
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	$ 763,415	$	$	$ 105,334	868,749
23	Prov. for uncollectibles					
24	for year	69,823			29,501	99,324
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 833,238	$ -	$ -	$ 134,835	$ 968,073
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	$ 99,678	$ 126,648	$ 226,326	$ -	
15						
16	IDACORP, Inc.	$ 537,406	$ 68,950,651	$ 69,488,057	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ 637,084	$ 69,077,299	$ 69,714,383	$ -	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.

2. Individual gains or losses relating to property with an original cost of less than $50,000 may be grouped, with the number of such transactions disclosed in column (a).

3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	Willis Sub disposal of original property	$ 109,303		$ -	
5					
6	Dike Power Site reclassify to account 101	69,539		$ (2,893)	
7					
8					
9	Misc Items	330		$ 155	
10					
11					
12					
13					
14	Total gain..	$ 179,171		$ (2,738)	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss...	$ 0			$ 0

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	ADECCO	Mapping Services	$ 46,659
2	AERO-GRAPHICS	Mapping Services	62,206
3	ASCENTIUM CORPORATION	PM Consultant	31,774
4	ASHLEY LAND SERVICES	Environmental Services	25,779
5	ATER, WYNNE LLP	Legal Services	289,313
6	BAKER, KEN	Management Services	13,500
7	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	244,768
8	BERBER, GAYNOL LEE	Legal Services	55,000
9	BIDART & ROSS INC	Management Services	72,726
10	BLACKBURN & JONES LLP	Legal Services	216,201
11	BLANK & ASSOCIATES P.S.	Computer Support Services	111,085
12	BOISE COURTYARD BY MARRIOTT	Consulting Services	12,400
13	BRENNEMAN, JOHN	Lobby Services	73,728
14	BRIGHAM YOUNG UNIVERSITY	Environmental Services	52,124
15	BROWN RUDNICK BERLACK ISRAELS	Lobby Services	54,000
16	BROWNSTEIN HYATT & FARBER, P C	Legal Services	899,408
17	BUSINESS LEGAL CONSULTING	Legal Services	14,960
18	CAPITOLWEST PUBLIC POLICY	Consulting Services	60,000
19	CAPROCK GROUP INC, THE	Management Services	24,000
20	CASCADE ENERGY ENGINEERING INC	Engineering Services	13,663
21	CH2M HILL	Engineering Services	82,106
22	CHAVEZ WRITING & EDITING, INC	Management Services	15,825
23	CHURCH, JOHN S	Economic Services	72,000
24	COMMUNICATIONS ET AL	Advertising Services	77,256
25	COMMVAULT SYSTEMS, INC	Environmental Services	25,000
26	CONNOR CLAIMS SPECIALISTS	Management Services	13,009
27	CORNERSTONE SYSTEMS INC	Computer Support Services	503,950
28	CRI ADVANTAGE	Computer Support Services	93,240
29	CTA ARCHITECTS	Architect Services	81,820
30	CUMMINS & BARNARD, INC.	Environmental Services	141,820
31	DAVID EVANS AND ASSOCIATES	Management Services	123,056
32	DAVIS WRIGHT TREMAINE LLP	Legal Services	1,687,246
33	DEAN & CARTER PLLC	Legal Services	14,023
34	DELOITTE & TOUCHE LLP	Accounting Services	1,203,589
35	DESERT RESEARCH INSTITUTE	Environmental Services	36,557
36	DHI INC	Environmental Services	40,102
37	EAGLE CAP CONSULTING INC	Environmental Services	112,043
38	ECOANALYSTS INC	Environmental Services	120,069
39	EIDAM AND ASSOCIATES	Engineering Services	10,219
40	EMPLOYEASE INC.	Consulting Services	56,658
41	ENERNEX CORPORATION	Consulting Services	127,042
42	ENGLAND CONSULTING	Consulting Services	37,950
43	ERNST & YOUNG LLP	Accounting Services	121,554
44	EVANS KEANE	Management Services	12,882
45	EVANS RANGE RECLAMATION	Management Services	16,413

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	$ 15,189
47	GORDON LAW OFFICES TRUST ACCOU	Legal Services	61,235
48	HALL FARLEY OBERRECHT & B	Legal Services	36,124
49	HARDESTY, REBECCA	Environmental Services	20,905
50	HDR ENGINEERING, INC	Engineering Services	23,274
51	HISTORY ASSOCIATES, INC.	Consulting Services	205,115
52	HOPKINS RODEN CROCKETT HANSEN	Lobby Services	70,894
53	HR MANAGEMENT SOLUTIONS LLC	Management Services	10,688
54	HYQUAL	Management Services	24,805
55	IBM	Computer Support Services	14,551
56	IDAHO STATE UNIVERSITY	Environmental Services	13,339
57	INTERMOUNTAIN TECHNOLOGY GROUP	Computer Support Services	462,002
58	JUB ENGINEERS	Engineering Services	53,988
59	LE BOEUF LAMB GREENE	Legal Services	2,099,367
60	LOWDER, LONNIE	Legal Services	45,000
61	MALANDRO COMMUNICATION INC	Consulting Services	769,231
62	MAPFRAME CORPORATION	Computer Support Services	72,845
63	MARSH ADVANTAGE AMERICA	Management Services	27,039
64	MERRILL & MERRILL CHARTERED	Legal Services	11,618
65	MILLER BATEMAN LLP	Legal Services	166,668
66	MODERN MANAGEMENT INC	Management Services	30,568
67	MUSSETTER ENGINEERING INC	Engineering Services	13,843
68	MWH AMERICAS, INC.	Management Services	71,329
69	NIELSEN GROUP INC, THE	Consulting Services	148,176
70	NOVELL, INC.	Environmental Services	91,425
71	ORACLE CORPORATION	Computer Support Services	46,295
72	PAINE, HAMBLEN, COFFIN , BROOK	Management Services	69,425
73	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	42,479
74	PERKINS COIE LLP	Legal Services	54,824
75	PERSONNEL PLUS	Management Services	26,448
76	PLANNEDSCAPE	Consulting Services	26,564
77	POWER ENGINEERS INC	Engineering Services	205,235.47
78	QUAKER LANE ASSOCIATES	Management Services	37,779.03
79	RESOLVE, INC	Management Services	22,963.74
80	RIDDELL WILLIAMS P.S.	Legal Services	113,639.31
81	RIVERSIDE TECHNOLOGY INC	Management Services	294,883.07
82	RLW ANALYTICS, INC	Environmental Services	20,017.75
83	ROBERT J RIETH	Legal Services	23,816.50
84	ROSEMARY BRENNAN CURTIN, INC	Management Services	94,202.40
85	SAINT ALPHONSUS REGIONAL MEDIC	Medical Consulting	28,420.00
86	SALLADAY & DAVIS	Legal Services	64,758.63
87	SCIENCE APPLICATIONS INTE	Environmental Services	12,832.20
88	SMITH, CURTIS D	Cloud Seeding Services	59,325.98
89	SOFTWARE AG INC	Computer Support Services	137,080.00

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	SPATIAL NETWORK SOLUTIONS	Management Services	$ 37,489
91	SPL WORLDGROUP INC	Computer Support Services	343,488
92	STAHMAN, ROBERT W	Legal Services	94,913
93	STANLEY ASSOCIATES, INC	Management Services	13,030
94	STATE OF IDAHO FISH & GAME	Environmental Services	54,809
95	STEPTOE & JOHNSON LLP	Legal Services	422,592
96	STOEL RIVES LLP	Legal Services	26,312
97	SULLIVAN & CROMWELL	Management Services	194,852
98	SUMMIT BLUE CONSULTING LLC	Consulting Services	37,218
99	SWANSON ENTERPRISES LLC	Consulting Services	12,265
100	SWCA, INC	Environmental Services	87,997
101	SYSTEM PROTECTION SERVICES, PL	Engineering Services	93,357
102	TOWERS PERRIN HR SERVICES	Management Services	190,892
103	TREASURE VALLEY LEGAL SERVICES	Legal Services	75,728
104	UNIVERSITY OF IDAHO	Environmental Services	134,205
105	VAN NESS FELDMAN	Legal Services	614,862
106	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	27,348
107	YTURRI, ROSE, BURNHAM, BENTZ	Legal Services	12,954
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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	AMEC EARTH & ENVIRONMENTAL, IN	Environmental Services	$	9,488
2	ASPEN GROVE ECOLOGICAL SERVICE	Environmental Services		5,706
3	BLUE WORLD INFORMATION TECHNOL	Management Services		7,264
4	BRICKLEY, SEARS & SORETT, P.A.	Legal Services		6,500
5	CAPITAL BRIDGE	Management Services		8,608
6	DC ENGINEERING, PC	Engineering Services		6,650
7	DEVINE, TARBELL & ASSOC INC	Environmental Services		5,784
8	ECOS CONSULTING	Consulting Services		7,200
9	ENGINEERING INCORPORATED	Engineering Services		7,060
10	ENGLAND CONSTRUCTION	Engineering Services		5,100
11	GARRAD HASSAN AMERICA INC	Environmental Services		5,755
12	MATERIALS TESTING & INSPE	Management Services		8,812
13	PACIFIC INTERNATIONAL ENGINEER	Engineering Services		8,229
14	PLATEAU SYSTEMS LTD	Management Services		5,250
15	RAIN SHADOW RESEARCH, INC	Environmental Services		5,189
16	RAPIDIGM INC	Computer Consulting Services		5,546
17	SCOTTSDALE RESORT & CONFERENCE	Management Services		7,490
18	SOUTH LANDSCAPE ARCHITECTS	Engineering Services		5,564
19	THORNTON CONSULTING	Management Services		8,151
20	TROUTMAN SANDERS LLP	Legal Services		7,000
21	ZGA ARCHITECTS & PLANNERS	Architectural Services		7,630
22				
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ELECTRIC PLANT IN SERVICE (Accounts 10

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	$ 62,945	
3	(302) Franchises and Consents	17,894,190	
4	(303) Miscellaneous Intangible Plant	46,383,713	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	64,340,848	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	3,430,383	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	779,416,892	
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)	596,589,744	
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		

1, 102, 103 and 106)

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
			$ 57,529	(301)	2
			20,553,832	(302)	3
			46,571,649	(303)	4
			67,183,011		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			3,982,426	(317)	15
			793,884,294		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
			613,086,985		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)	$ 99,694,684	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,475,701,320	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	21,047,463	
49	(352) Structures and Improvements	28,117,792	
50	(353) Station Equipment	199,533,892	
51	(354) Towers and Fixtures	67,625,521	
52	(355) Poles and Fixtures	76,407,981	
53	(356) Overhead Conductors and Devices	96,515,357	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	259,238	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	489,507,245	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,719,974	
61	(361) Structures and Improvements	18,660,144	
62	(362) Station Equipment	129,980,459	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	174,103,722	
65	(365) Overhead Conductors and Devices	89,295,291	
66	(366) Underground Conduit	40,992,386	
67	(367) Underground Conductors and Devices	151,082,701	
68	(368) Line Transformers	266,919,861	
69	(369) Services	45,946,816	
70	(370) Meters	48,247,223	
71	(371) Installations on Customer Premises	2,291,375	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,798,654	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	978,038,606	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	7,937,421	
78	(390) Structures and Improvements	56,620,933	
79	(391) Office Furniture and Equipment	45,779,692	
80	(392) Transportation Equipment	43,849,209	
81	(393) Stores Equipment	898,339	
82	(394) Tools, Shop, and Garage Equipment	3,842,719	
83	(395) Laboratory Equipment	8,543,043	
84	(396) Power Operated Equipment	6,700,450	
85	(397) Communication Equipment	24,069,684	
86	(398) Miscellaneous Equipment	2,419,657	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	200,661,147	
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)	200,661,147	
91	TOTAL (Accounts 101 and 106)	3,208,249,165	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 3,208,249,165	

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
			$ 101,232,115		45
			1,508,203,394		46
					47
			24,675,658	(350)	48
			31,520,034	(352)	49
			210,231,053	(353)	50
			84,489,667	(354)	51
			64,309,387	(355)	52
			102,055,096	(356)	53
				(357)	54
				(358)	55
			261,954	(359)	56
				(359.1)	57
			517,542,847		58
					59
			4,341,499	(360)	60
			19,267,383	(361)	61
			134,544,631	(362)	62
				(363)	63
			178,077,556	(364)	64
			91,808,497	(365)	65
			43,012,125	(366)	66
			159,571,691	(367)	67
			289,800,410	(368)	68
			48,616,312	(369)	69
			50,592,870	(370)	70
			2,358,293	(371)	71
				(372)	72
			3,860,189	(373)	73
				(374)	74
			1,025,851,456		75
					76
			8,108,134	(389)	77
			59,594,282	(390)	78
			34,567,743	(391)	79
			47,247,737	(392)	80
			909,180	(393)	81
			3,907,749	(394)	82
			9,033,982	(395)	83
			6,762,653	(396)	84
			26,096,312	(397)	85
			2,688,355	(398)	86
			198,916,128		87
				(399)	88
				(399.1)	89
			198,916,128		90
			3,317,696,836		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 3,317,696,836		96

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 289,068,594	$ 289,325,450
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	221,723,109	237,308,467
5	Large (or Industrial)(See Instr. 4) (2)	93,623,913	107,515,732
6	(444) Public Street and Highway Lighting	2,290,770	2,312,403
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	606,706,387 *	636,462,052
11	(447) Sales for Resale - Opportunity....Non-Firm Only	242,715,342	130,947,067
12	TOTAL Sales of Electricity	849,421,730	767,409,119
13	(449.1) Provision for Rate Refunds	(1,211,251)	400,102
14	TOTAL Revenue Net of Provision for Refunds	848,210,479	767,809,221
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	5,368,289	5,415,794
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	15,142,580	15,930,432
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,748,184	13,758,967
22			
23			
24			
25	TOTAL Other Operating Revenues	28,259,054	35,105,192
26	TOTAL Electric Operating Revenues	$ 876,469,532	$ 802,914,413

(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
4,868,383,891	4,569,022,693	374,527	360,484	2
				3
5,170,019,354	4,880,517,406	71,472	69,642	4
3,170,158,215	3,135,239,312	122	121	5
27,402,244	27,802,162	768	619	6
				7
				8
				9
13,235,963,704 **	12,612,581,573	446,889	430,866	10
5,492,528,583	2,611,581,658	N/A	N/A	11
18,728,492,287	15,224,163,231	446,889	430,866	12
				13

* Includes $ -6,009,627 unbilled revenues.

** Includes 20,084,846 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	$ 1,621,185	$ 1,206,279
5	(501) Fuel	101,451,974	93,196,241
6	(502) Steam Expenses	6,706,052	6,492,450
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	1,362,769	1,516,621
10	(506) Miscellaneous Steam Power Expenses	7,708,765	6,415,549
11	(507) Rents	235,366	307,012
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	119,086,112	109,134,153
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,390,796	2,011,225
16	(511) Maintenance of Structures	387,046	398,053
17	(512) Maintenance of Boiler Plant	14,509,643	14,928,572
18	(513) Maintenance of Electric Plant	4,183,656	5,283,963
19	(514) Maintenance of Miscellaneous Steam Plant	4,331,618	1,171,554
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,802,758	23,793,367
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	144,888,870	132,927,521
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	4,280,591	4,301,903
45	(536) Water for Power	4,674,353	4,028,245
46	(537) Hydraulic Expenses	7,818,109	7,707,802
47	(538) Electric Expenses	1,312,063	1,193,152
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,278,711	1,788,748
49	(540) Rents	387,654	339,221
50	TOTAL Operation (Enter Total of lines 44 thru 49)	20,751,482	19,359,072

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 1,771,573	$ 1,204,479
54	(542) Maintenance of Structures	1,129,692	849,491
55	(543) Maintenance of Reservoirs, Dams, and Waterways	896,199	645,746
56	(544) Maintenance of Electric Plant	2,022,387	2,326,595
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,042,284	2,695,213
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,862,134	7,721,523
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	29,613,616	27,080,595
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	305,152	368,857
63	(547) Fuel	7,075,143	3,937,048
64	(548) Generation Expenses	274,538	218,019
65	(549) Miscellaneous Other Power Generation Expenses	281,369	316,913
66	(550) Rents	0	6,363
67	TOTAL Operation (Enter Total of lines 62 thru 66)	7,936,201	4,847,200
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	164	183
70	(552) Maintenance of Structures	167,535	241,128
71	(553) Maintenance of Generating and Electric Plant	117,540	28,556
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	371,585	404,791
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	656,823	674,659
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	8,593,024	5,521,859
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	267,452,726	209,322,905
77	(556) System Control and Load Dispatching	72,080	73,156
78	(557) Other Expenses	(25,848,541)	(966,244)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	241,676,264	208,429,817
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	424,771,774	373,959,791
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,163,362	1,698,144
84	(561) Load Dispatching	3,010,532	2,539,804
85	(562) Station Expenses	1,596,812	1,346,029
86	(563) Overhead Line Expenses	738,876	432,874
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	7,207,592	7,209,525
89	(566) Miscellaneous Transmission Expenses	230,883	251,009
90	(567) Rents	982,438	1,320,471
91	TOTAL Operation (Enter Total of lines 83 thru 90)	15,930,496	14,797,857
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	393,040	586,972
94	(569) Maintenance of Structures	169,741	57,860
95	(570) Maintenance of Station Equipment	2,480,807	2,274,825
96	(571) Maintenance of Overhead Lines	1,917,736	1,603,680
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	26,623	13,871
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	4,987,948	4,537,207
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	20,918,444	19,335,065
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	2,853,198	3,592,185

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	$ 2,847,658	$ 2,385,842
106	(582) Station Expenses	1,091,619	887,177
107	(583) Overhead Line Expenses	3,544,944	2,726,164
108	(584) Underground Line Expenses	2,008,479	1,703,802
109	(585) Street Lighting and Signal System Expenses	146,732	114,536
110	(586) Meter Expenses	4,122,897	3,934,241
111	(587) Customer Installations Expenses	1,028,502	692,207
112	(588) Miscellaneous Distribution Expenses	5,227,173	4,300,696
113	(589) Rents	140,239	147,491
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,011,442	20,484,342
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	208,690	85,167
117	(591) Maintenance of Structures	0	64,820
118	(592) Maintenance of Station Equipment	2,659,704	2,468,821
119	(593) Maintenance of Overhead Lines	10,129,328	10,039,765
120	(594) Maintenance of Underground Lines	1,096,396	1,090,650
121	(595) Maintenance of Line Transformers	530,254	292,049
122	(596) Maintenance of Street Lighting and Signal Systems	674,996	359,616
123	(597) Maintenance of Meters	861,056	740,287
124	(598) Maintenance of Miscellaneous Distribution Plant	133,375	215,370
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	16,293,800	15,356,544
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	39,305,242	35,840,885
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	512,985	471,754
130	(902) Meter Reading Expenses	4,958,009	4,449,433
131	(903) Customer Records and Collection Expenses	9,753,911	8,922,800
132	(904) Uncollectible Accounts	2,770,604	1,389,879
	(905) Miscellaneous Customer Accounts Expenses	356	26,596
	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	17,995,866	15,260,462
	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
	Operation		
	(907) Supervision	281,641	273,766
138	(908) Customer Assistance Expenses	8,822,366	8,354,446
139	(909) Informational and Instructional Expenses	192	0
140	(910) Miscellaneous Customer Service and Informational Expenses	826,658	743,988
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	9,930,857	9,372,200
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	45,701,139	37,712,128
152	(921) Office Supplies and Expenses	13,696,615	15,031,267
153	(Less) (922) Administrative Expenses Transferred-Credit	(27,386,005)	(22,062,446)

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	$ 7,610,977	$ 7,296,517
156	(924) Property Insurance	2,744,172	2,662,273
157	(925) Injuries and Damages	4,811,467	5,326,569
158	(926) Employee Pensions and Benefits	27,309,084	21,409,065
159	(927) Franchise Requirements	2,000	2,300
160	(928) Regulatory Commission Expenses	(316,513)	3,335,147
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	100,217	112,265
163	(930.2) Miscellaneous General Expenses	1,775,497	1,731,007
164	(931) Rents	3,705	3,506
165	TOTAL Operation (Enter Total of lines 151 thru 164)	76,052,354	72,559,597
166	Maintenance		
167	(935) Maintenance of General Plant	3,673,670	3,204,656
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	79,726,024	75,764,253
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)		$ 529,532,657

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, 2006	December 31, 2005
2	Total Regular Full-Time Employees	1,871	1,774
3	Total Part-Time and Temporary Employees	38	29
4	Total Employees	1,909	1,803