ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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2007 JUN 13 AM 9:05
IDAHO PUBLIC UTILITIES COMMISSION

201 South Main, Suite 2300
Salt Lake City, Utah 84111

June 13, 2007

Idaho Public Utilities Commission
472 West Washington
Boise, ID 83702-5983

Attention: Jean D. Jewell
Commission Secretary

Re: 2006 FERC Form 1

PacifiCorp (d.b.a. Rocky Mountain Power) hereby submits for filing an original and seven (7) conformed copies of its 2006 FERC Form 1. The 2006 FERC Form 1 is not available in electronic format and will be provided hard copy via overnight delivery.

It is respectfully requested that all formal correspondence and Staff requests regarding this material be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon, 97232

By fax: (503) 813-6060

Informal questions should be directed to Brian Dickman at (801) 220-4052.

Sincerely,

Jeffrey K. Larsen / [signature]

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

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)

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
PacifiCorp	End of 2006/Q4

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 PacifiCorp	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)* 825 N.E. Multnomah, Suite 1900 Portland, OR 97232	
05 Name of Contact Person Henry E. Lay	06 Title of Contact Person Corp. Accounting Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 825 N.E. Multnomah, Suite 1900 Portland, OR 97232	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 813-6179	(1) [X] An Original (2) [ ] A Resubmission	04/06/2007

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
David J. Mendez	David J. Mendez	5/17/07
02 Title Senior VP & Chief Financial Officer		

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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	NA
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	NA
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	NA
24	Unrecovered Plant and Regulatory Study Costs	230	
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Long-Term Debt	269	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	NA
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	NA
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	NA
55	Amounts included in ISO/RTO Settlement Statements	397	NA
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	NA
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	
63	Pumped Storage Generating Plant Statistics	408-409	NA
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 05/17/2007	Year/Period of Report 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.

David J. Mendez, Senior Vice President and Chief Financial Officer
825 N.E. Multnomah, Suite 1900
Portland, OR 97232-4116

Corporate books are kept at:
825 N.E. Multnomah, Suite 1900
Portland, OR 97232-4116

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.

Incorporated on August 11, 1987 in the State of Oregon.

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.

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.

The Company is a regulated electric company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The Company conducts its retail electric utility business as Pacific Power and Rocky Mountain Power, and engages in electricity production and sales on a wholesale basis under the trade name PacifiCorp Energy.

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) [X] Yes...Enter the date when such independent accountant was initially engaged: 05/31/2006
(2) [ ] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.

Berkshire Hathaway Inc.

MidAmerican Energy Holdings Company (100%)(88.2% controlled by Berkshire Hathaway Inc.)

PPW Holdings LLC (100% controlled by MidAmerican Energy Holdings Company)

PacifiCorp (99.78% controlled by PPW Holdings LLC)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Centralia Mining Company	Mining	100	
2	Energy West Mining Company	Mining	100	
3	Glenrock Coal Company	Mining	100	
4	Interwest Mining Company	Mining	100	
5	Pacific Minerals, Inc.	Mining	100	
6	Bridger Coal Company	Mining	66.67	
7	PacifiCorp Environmental Remediation Company	Environmental Services	90.00	
8	PacifiCorp Future Generations, Inc.	Rain Forest Carbon Credits	100	
9	PacifiCorp Investment Management, Inc.	Management Services for PERCo	100	
10	Trapper Mining, Inc.	Mining	21.40	
11	Intermountain Geothermal Company	Steam Delivery Service	100	
12	Steam Reserve Corporation	Steam Delivery Service	100	
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Schedule Page: 103 Line No.: 1 Column: a

In May 2000, the assets of Centralia Mining Company were sold to TransAlta.

Schedule Page: 103 Line No.: 6 Column: a

Idaho Power Corp. holds a 33.33% ownership interest in Bridger Coal Company. PacifiCorp's interest is held through Pacific Minerals, Inc.

Schedule Page: 103 Line No.: 7 Column: a

CH2MHill holds a 10.0% ownership interest in PacifiCorp Environmental Remediation Company.

Schedule Page: 103 Line No.: 8 Column: a

PacifiCorp Future Generations owns an interest in Canopy Botanicals, Inc., which holds an interest in Canopy Botanicals, SRL relating to rain forest carbon emissions credits.

Schedule Page: 103 Line No.: 10 Column: a

The other joint owners of Trapper Mining, Inc. are Salt River Project (32.10%), Tri-State Generation and Transmission Association, Inc. (26.57%) and Platte River Power Authority (19.93%).

Schedule Page: 103 Line No.: 12 Column: a

In July 2006, Intermountain Geothermal Company purchased all of the outstanding capital stock of Steam Reserve Corporation.

For a further discussion of Intermountain Geothermal Company not described in this item, refer to ITEM 2 of the *Important Changes During the Year* of this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Executive Officers as of December 31, 2006		
2	Chairman of the Board and Chief Executive Officer	Gregory E. Abel	
3	Senior Vice President and Chief Financial Officer	David J. Mendez	192,917
4	President, PacifiCorp Energy	William J. Fehrman	201,042
5	President, Pacific Power	Patrick Reiten	67,746
6	President, Rocky Mountain Power	A. Richard Walje	330,811
7	Sr. VP, General Counsel & Corporate Secretary	Andrew P. Haller	3,254,463
8			
9	Other Executive Officers in 2006		
10	President and Chief Executive Officer	Judith A. Johansen	3,101,355
11	Chief Financial Officer and Senior Vice President	Richard D. Peach	2,398,791
12	Executive Vice President	Matthew R. Wright	1,645,683
13	Executive Vice President	Andrew N. MacRitchie	1,703,187
14	Senior Vice President	Stanley K. Watters	577,469
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Schedule Page: 104 Line No.: 1 Column: a

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2006, consistent with Item 402 of Regulation S-K s promulgated by the Securities and Exchange Commission. Salary information of other officers will be provided to the Commission upon request, but the company considers such information personal and confidential to such Officers. See 18 CFR 388.107(d), (f).

Schedule Page: 104 Line No.: 2 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. Able receives no direct compensation from PacifiCorp. PacifiCorp reimburses MEHC for the cost of Mr. Abel's time spent on PacifiCorp matters, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries. Please refer to MEHC's annual report on Form 10-K for the year ended December 31, 2006 (File No. 001-14881) for executive compensation information for Mr. Abel.

Schedule Page: 104 Line No.: 3 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1.

Schedule Page: 104 Line No.: 4 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1.

Schedule Page: 104 Line No.: 5 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1.

Schedule Page: 104 Line No.: 6 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1.

Schedule Page: 104 Line No.: 7 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. Haller resigned as a director and executive officer of PacifiCorp effective December 31, 2006. Total remuneration, including severance benefits, for the period of January 1, 2006 to December 31, 2006 was $3,254,463.

Schedule Page: 104 Line No.: 9 Column: a

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2006, consistent with Item 402 of Regulation S-K s promulgated by the Securities and Exchange Commission. Salary information of other officers will be provided to the Commission upon request, but the company considers such information personal and confidential to such Officers. See 18 CFR 388.107(d), (f).

Schedule Page: 104 Line No.: 10 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Ms. Johansen resigned as a director and executive officer of PacifiCorp on March 21, 2006. Total remuneration, including severance benefits, for the period of January 1, 2006 to March 21, 2006 was $3,101,355.

Schedule Page: 104 Line No.: 11 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. Peach resigned as a director and executive officer of PacifiCorp on November 22, 2006. Total remuneration, including severance benefits, for the period of January 1, 2006 to December 31, 2006 was $2,398,791.

Schedule Page: 104 Line No.: 12 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. Wright resigned as a director and executive officer of PacifiCorp on March 21, 2006. Total remuneration, including severance benefits, for the period of January 1, 2006 to March 21, 2006 was $1,645,683.

Schedule Page: 104 Line No.: 13 Column: b

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. MacRitchie resigned as a director and executive officer of PacifiCorp on March 21, 2006. Total remuneration, including severance benefits, for the period of January 1, 2006 to March 21, 2006 was $1,703,187.

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

For additional information regarding changes in the status of PacifiCorp's officers refer to page 108, *Important Changes During the Year*, ITEM 13, of this Form No. 1. Mr. Watters resigned as President of Pacific Power, on September 15, 2006. Total earnings for the period of January 1, 2006 to September 15, 2006 was $577,469.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	PacifiCorp Board of Directors as of December 31, 2006:	
2	Gregory E. Abel (Chairman of the Board and CEO, PacifiCorp)	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309
3	William J. Fehrman (President, PacifiCorp Energy)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
4	Patrick Reiten (President, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
5	A. Richard Walje (President, Rocky Mountain Power)	201 South Main, Suite 2400, Salt Lake City, Utah 84140
6	Douglas L. Anderson	302 South 36th Street, Omaha, Nebraska 68131
7	Brent E. Gale	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
8	Patrick J. Goodman	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309
9	Nolan E. Karras	4695 South 1900 West #3, Roy, Utah 84067
10	A. R. Lasich	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
11	Andrew P. Haller (Senior Vice President)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
12	Mark C. Moench	201 South Main, Suite 2400, Salt Lake City, Utah 84140
13	Stanley K. Watters (Senior Vice President, PacifiCorp)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
14		
15	Other Directors in 2006	
16	Ian M. Russell, Chairman of the Board	1 Atlantic Quay, Glasgow, Scotland G2 8SP UK
17	**Judith A. Johansen (President & CEO)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
18	***Richard D. Peach (Chief Financial Officer)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
19	***Andrew N. MacRitchie (Executive Vice President)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
20	***Matthew R. Wright (Executive Vice President)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
21	***Barry G. Cunningham (Senior Vice President)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
22	Stephen Dunn	1 Atlantic Quay, Glasgow, Scotland G2 8SP UK
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) X An Original (2) _ A Resubmission	05/17/2007	2006/Q4

FOOTNOTE DATA

Schedule Page: 105 Line No.: 2 Column: a

Mr. Abel was elected March 21, 2006. For additional information regarding Mr. Abel refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Currently there is only one committee, a Compensation Committee, of which the sole member is Mr. Abel.

Schedule Page: 105 Line No.: 3 Column: a

Mr. Fehrman was elected March 21, 2006. For additional information regarding Mr. Fehrman refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 4 Column: a

Mr. Reiten was elected September 15, 2006. For additional information regarding Mr. Reiten refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 6 Column: a

Mr. Anderson was elected March 21, 2006. For additional information regarding Mr. Anderson refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 7 Column: a

Mr. Gale was elected March 21, 2006. For additional information regarding Mr. Gale refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 8 Column: a

Mr. Goodman was elected March 21, 2006. For additional information regarding Mr. Goodman refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 10 Column: a

Mr. Lasich was elected March 21, 2006. For additional information regarding Mr. Lasich refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 11 Column: a

Mr. Haller resigned December 31, 2006. For additional information regarding Mr. Haller refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 12 Column: a

Mr. Moench was elected March 21, 2006. For additional information regarding Mr. Moench refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 13 Column: a

Mr. Watters was elected March 21, 2006. For additional information regarding Mr. Watters refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 16 Column: a

Mr. Russell resigned January 16, 2006.

Schedule Page: 105 Line No.: 17 Column: a

Ms. Johansen resigned March 21, 2006. For additional information regarding Ms. Johansen refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 18 Column: a

Mr. Peach resigned November 22, 2006. For additional information regarding Mr. Peach refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 19 Column: a

Mr. MacRitchie resigned March 21, 2006. For additional information regarding Mr. MacRitchie refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 20 Column: a

Mr. Wright resigned March 21, 2006. For additional information regarding Mr. Wright refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 21 Column: a

Mr. Cunningham resigned March 21, 2006. For additional information regarding Mr. Cunningham refer to Page 108, *Important Changes During the Year*, Item 13, of this Form No. 1.

Schedule Page: 105 Line No.: 22 Column: a

Mr. Dunn resigned March 21, 2006. For additional information regarding Mr. Dunn refer to Page 108, *Important Changes During the*

Year, Item 13, of this Form No. 1.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.

ITEM 1.

Changes in Franchise Rights

State	Effective Date	Expiration Date	Fee % (Fee attached to franchise agreement)
California (a)			
Siskiyou County	1/12/2006	1/12/2021	2.0%
Idaho (b)			
None			
Oregon (c)			
Powers	03/20/2006	03/20/2016	5.0%
Roseburg	04/08/2006	04/08/2016	5.0%
Shady Cove	07/01/2006	06/30/2023	7.0%
Pendleton	08/01/2006	(e)	7.0%
Winston	08/05/2006	08/05/2016	5.0%
Cave Junction	09/29/2006	09/29/2026	7.0%
Canyonville	10/16/2006	10/16/2016	5.0%
Cottage Grove	10/09/2006	10/09/2016	3.5%
Utah (b)			
Lehi/Micron Plant	04/07/2006	04/07/2007	
Panguitch	04/07/2006	04/07/2011	
Sevier County	05/04/2006	05/04/2031	
Murray City	06/05/2006	06/05/2031	
Glenwood	06/30/2006	06/30/2016	
Herriman	07/01/2006	08/19/2019	
Centerville City	10/11/2006	10/11/2011	
North Salt Lake	10/24/2006	10/24/2011	
Rush Valley	10/25/2006	10/25/2026	
Alpine	11/28/2006	11/28/2026	
Washington (b)			
None			
Wyoming (d)			
Diamondville	01/16/2006	01/16/2026	1.0%
Big Piney	03/14/2006	03/14/2026	1.0%
Sinclair	04/07/2006	04/07/2016	2.0%
Wamsutter	04/19/2006	04/19/2026	2.0%
Bairoil	06/19/2006	06/19/2031	2.0%

(a) In the state of California, franchise fees are an expense to PacifiCorp and are embedded in rates.

(b) In the states of Idaho, Utah and Washington, PacifiCorp collects franchise fees from customers and remits them directly to the applicable municipalities.

(c) In the state of Oregon, the first 3.5% of the franchise fee is an expense to PacifiCorp and is embedded in rates. For any amount above the 3.5%, PacifiCorp collects franchise fees from customers and remits them directly to the applicable municipalities.

(d) In the State of Wyoming, the first 1.0% of the franchise fees is an expense to PacifiCorp and is embedded in rates. For any amount above the 1.0%, PacifiCorp collects franchise fees from customers and remits them directly to the applicable municipalities.

(e) On June 6, 2006, the Pendleton City Council adopted Ordinance 3733, amending Ordinance 2814. This ordinance remains effective indefinitely.

ITEM 2.

Acquisition of Ownership in Other Companies

PacifiCorp Environmental Remediation Company
PacifiCorp Environmental Remediation Company ("PERCo") became a wholly owned subsidiary of PacifiCorp in April 2007, when PacifiCorp acquired the outstanding 10% minority interest in PERCo for $150,000.

Intermountain Geothermal
As a result of a settlement agreement between MidAmerican Energy Holdings Company ("MEHC"), the Utah Committee of Consumer Services and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell geothermal plant in Utah. Intermountain Geothermal Company ("IGC") therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

Steam Reserve Corporation
In July 2006, IGC purchased all of the outstanding capital stock of Steam Reserve Corporation, which controls 24.0% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell geothermal plant in Utah. As a result, Steam Reserve Corporation became a wholly owned subsidiary of IGC in July 2006. Commission authorization was not required.

With this purchase and the purchase disclosed in ITEM 4, Intermountain Geothermal now owns 94.5% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell geothermal plant.

For a further discussion of IGC not described in this item, refer to ITEM 4 of this Form No. 1.

ITEM 3.

Purchase or Sale of an Operating Unit

Sale of Upper Beaver Hydro Project
In March 2006, PacifiCorp and the city of Beaver, Utah entered into a Project Purchase Agreement whereby PacifiCorp would request approval from its state regulators to sell the Upper Beaver Hydro Project to the City of Beaver, Utah. The sale is contingent upon a number of items, one of which is the separation of the generation and transmission and distribution facilities in the power plant switchyard to facilitate wheeling of the future power generated. The sale is expected to close in mid-2007.

ITEM 4.

Important Leaseholds

West Valley Generating Facility
In May 2002, PacifiCorp entered into a 15-year operating lease for an electric generation facility with West Valley Leasing Company, LLC ("West Valley"). West Valley is an indirect subsidiary of PacifiCorp's former parent ScottishPower PLC. The facility consists of five generation units, each rated at 40 megawatts ("MW"), and is located in Utah. The lease terms granted PacifiCorp two independent early termination options that provide PacifiCorp the right to terminate the lease and, at PacifiCorp's further option, to purchase the facility for predetermined amounts. On May 28, 2004, PacifiCorp exercised its first option to terminate the lease and subsequently exercised its right to rescind the termination on September 28, 2004. On December 1, 2006, PacifiCorp waived its option to purchase

the facility under the lease for $122.5 million and exercised its second option to terminate the lease. As such, PacifiCorp is committed to future minimum lease payments of $10.0 million for the year ending December 31, 2007 and $4.4 million for the year ending December 31, 2008.

Lake Side Gas Lateral
In February 2005, PacifiCorp entered into a 30-year Agreement for Firm Transportation to PacifiCorp Lake Side Generating Facilities ("TSA") with Questar Gas Company ("Questar"). The TSA sets forth the terms for the provision of natural gas transportation service to the Lake Side power plant and construction of an approximately 5.3-mile natural gas pipeline and facilities necessary to connect the Lake Side power plant to Questar's existing feeder line.

The construction of the pipeline was declared "substantially complete" by Questar on November 9, 2006 and final construction costs are being accumulated to facilitate the calculation of the initial monthly reservation ("IMR") charge, initially estimated at $1.04654 per decatherm based on usage of a minimum 190,000 decatherms per month. The reservation charges decrease to 85% of the IMR for years six through ten, to 70% of the IMR for years eleven through fifteen and to 55% of the IMR for years sixteen through thirty. The estimated monthly charges under the TSA also include a component for reimbursement of the total construction costs of the pipeline and facilities, an amount not to exceed $13.4 million over the life of the lease, as well as executory fees such as monthly operation and maintenance costs and property taxes.

The TSA is considered a capital lease of the facilities and requires an estimated $2.4 million in minimum lease payments per year for years ending December 31, 2007 through 2010; $2.3 million for the year ending December 31, 2011; $2.0 million per year for the years ending December 31, 2012 – 2016; $1.7 million per year for the years ending December 31, 2017 – 2020; $1.6 million for the year ending December 31, 2021; $1.3 million per year for the years ending December 31, 2022 – 2035; and $1.1 million for the year ending December 31, 2036.

Marengo Land Leases & Easements
In October 2006, PacifiCorp announced the purchase of the 140.4-MW Marengo wind project from Blue Sky Wind, LLC, currently under construction near Dayton, Washington. As a result of this acquisition, PacifiCorp was assigned and assumed eighteen 35-year wind energy ground leases and transmission access easements from Blue Sky Wind, LLC with seventeen private land owners and the state of Washington's Department of Natural Resources, for use of the underlying land for the project.

The leases call for the payment of an installation fee of $3,000 per installed megawatt of nameplate-rated capacity, an annual floor payment equal to the greater of $2,000 or $25,000 per year or $1,000 per megawatt, or the sum of monthly production based payments based on an initial millage rate of $0.0015 per kilowatt hour of energy generated, subject to annual inflationary increases. Monthly production-based payments are credited towards the annual production payments.

Leaning Juniper Land Leases & Easements
In July 2006, PacifiCorp entered into an agreement with Leaning Juniper Wind Power, LLC to acquire a 100.5-MW wind energy generation facility near Arlington, Oregon that was currently under construction and began commercial operation during September 2006. As a result of this acquisition, PacifiCorp was assigned and assumed a 30-year site easement from Leaning Juniper Wind Power, LLC with Waste Management Disposal Services of Oregon, Inc. for use of the underlying land for the project.

The site easement calls for annual production payments equal to the greater of (a) $283,824 per year, (b) $1,000 times the aggregate megawatt capacity of all turbines on the respective properties, or (c) the sum of quarterly production based payments based on an initial millage rate of $0.0015 per kilowatt hour of energy generated, subject to annual inflationary increases. Quarterly production based payments are credited towards the annual production payments.

IGC Geothermal Leases
In June 2006, PacifiCorp's wholly owned subsidiary IGC entered into an asset purchase agreement with an individual for the rights to certain geothermal leases. The leases represent 1.2% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell geothermal plant in Utah. Commission authorization was not required.

For a further discussion of IGC not described in this item, refer to ITEM 2 of this Form No. 1.

ITEM 5.

Important Extension and Reduction of Transmission System

For a discussion on transmission lines added during the year refer to pages 424-425 of this Form No. 1. During the year ended December 31, 2006 PacifiCorp did not significantly increase or decrease its distribution system.

ITEM 6.

Financing Activities

Short-Term Debt
As of May 9, 2007, PacifiCorp had $20.0 million of commercial paper obligations outstanding, with maturities of less than one year. Authorizations for up to $1.5 billion outstanding at any one time in commercial paper and other unsecured short-term debt are as follows:

Utah Public Service Commission, Docket No. 06-035-027, Report and Order dated March 17, 2006.

Oregon Public Utility Commission, Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.

Washington Utilities and Transportation Commission, Docket No. UE-980404, dated April 8, 1998.

Idaho Public Utility Commission, Case No. PAC-E-06-01, Order No. 29999, dated March 14, 2006.

Securities and Exchange Commission, Release No. 35-27851, dated May 28, 2004 and filed with the FERC on February 6, 2006 pursuant to 18 CFR 366.6(b).

Long-Term Debt

On March 14, 2007, PacifiCorp issued $600.0 million of its 5.75% Series of First Mortgage Bonds due April 1, 2037. PacifiCorp intends to use the proceeds for general corporate purposes, including the reduction of short-term debt. State Commission authorizations for this issuance were as follows:

Utah Public Service Commission, Docket No. 07-035-05, Report and Order dated March 2, 2007, which authorized debt issuances of up to $1.5 billion as well as withdrew authorization for the remaining unissued $350.0 million in debt previously authorized in Docket No. 06-035-43.

Oregon Public Utility Commission, Docket No. UF-4237, Order No. 07-085, dated March 5, 2007, which authorized debt issuances of up to $1.5 billion as well as withdrew authorization for the remaining unissued $350.0 million in debt previously authorized under Order No. 05-258.

Washington Utilities and Transportation Commission, Docket No. UE-070450, Order No. 1, dated March 7, 2007.

Idaho Public Utilities Commission, Case No. PAC-E-07-2, Order No. 30258, dated February 27, 2007, which authorized debt issuances of up to $1.5 billion.

On August 10, 2006, PacifiCorp issued $350.0 million of its 6.10% Series of First Mortgage Bonds due August 1, 2036. PacifiCorp used the proceeds for general corporate purposes, including the reduction of short-term debt. State Commission authorizations for this issuance were as follows:

Utah Public Service Commission, Docket No. 06-035-43, Report and Order dated May 3, 2006, amended May 18, 2006.

Oregon Public Utility Commission, Docket No. UF-4215, Order No. 05-258, dated May 9, 2005.

Washington Utilities and Transportation Commission, Docket No. UE-050556, Order No. 2, dated June 14, 2006.

Idaho Public Utilities Commission, Case No. PAC-E-05-5, Order No. 29787, dated May 17, 2005.

Common Shareholder's Capital
On November 29, 2006, PacifiCorp received a capital contribution of $69.8 million in cash from its parent company, PPW Holdings LLC, a subsidiary of MEHC.

On September 26, 2006, PacifiCorp received a capital contribution of $71.6 million in cash from PPW Holdings LLC.

On June 26, 2006, PacifiCorp received a capital contribution of $73.6 million in cash from PPW Holdings LLC.

On March 21, 2006, PacifiCorp issued 9,902,728 shares of its common stock to its parent company at that time, PacifiCorp Holdings, Inc. ("PHI"), at a total price of $109.7 million. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4193(1), Order No. 05-729, dated June 7, 2005.

Washington Utilities and Transportation Commission, Docket No. UE-050555, Order No. 1, dated May 11, 2005.

Idaho Public Utilities Commission, Case No. PAC-E-05-4, Order No. 29786, dated May 17, 2005.

Revolving Credit and Other Financing Arrangements
PacifiCorp has an $800.0 million unsecured revolving credit facility expiring in July 2011 that supports PacifiCorp's commercial paper program. The credit facility includes a variable-rate borrowing option based on the London Interbank Offered Rate (LIBOR), plus a margin of 0.195%, that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. At December 31, 2006, there were no borrowings outstanding under this facility.

At December 31, 2006, PacifiCorp had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately $21.0 million of standby letters of credit available to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available at December 31, 2006 and expire periodically through February 2011.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1. At December 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

ITEM 7.

Changes in Articles of Incorporation or Amendments to Charter

None

ITEM 8.

Estimated Annual Effect of Wage Scale Changes

PacifiCorp's bargaining unit wage scale changes was as follows:

Unions Represented	% Increase (a)	Effective Date(s)	Estimated Annual Financial Impact (b)(c)
IBEW 57 Power Delivery (UT, ID & WY)	2.80%	1/26/2006	$ 2,073,970
IBEW 57 Generation (UT, ID & WY)	3.04%	1/26/2006	1,059,302
IBEW 659 (OR & CA)	3.35%	1/26/2006 & 7/26/2006	1,018,542
IBEW 127 (WY)	2.56%	3/26/2006 & 9/26/2006	1,011,257
IBEW 125 (WA & OR)	3.46%	1/26/2006 & 7/26/2006	953,441
UWUA 197 (Coos Bay, OR)	3.31%	1/26/2006 & 7/26/2006	52,236
IBEW 57 Combustion (UT, ID & WY)	2.63%	5/26/2006	41,864
IBEW 57 Laramie (WY)	2.59%	6/26/2006	13,563
Total			$ 6,224,175

(a) This percentage increase represents the increase of wages for all effective dates during the calendar year as compared to the wage scale of the prior effective period.
(b) Some amounts may be reimbursed by joint owners of steam generating facilities.
(c) The estimated annual impact is based on the time period from the effective date of the increase to the end of the calendar year.

ITEM 9.

For a discussion of other legal proceedings not described in this item, refer to *Notes to the Financial Statements – Note 12 – Contingencies* of this Form No. 1.

Legal Proceedings

In addition to the proceedings described below, PacifiCorp is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by PacifiCorp to have a material adverse effect on its financial results.

Legal Matters

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a compliant against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of air quality opacity standards at PacifiCorp's Jim Bridger Power Plant in Wyoming. Opacity is an indication of the amount of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least $812.0 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power is the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek Power Plant. USA Power's complaint alleges that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accuses PacifiCorp of breach of contract and related claims. USA Power seeks $250.0 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. A trial has been scheduled for January 2008. PacifiCorp believes it has a number of defenses and intends to vigorously oppose any claim of liability for the matters alleged by USA Power. Furthermore, PacifiCorp expects that the outcome of this proceeding will not have a material impact on its financial results.

In October 2005, the Utah Committee of Consumer Services (the "CCS") filed a request for agency action with the Utah Public Service Commission ("UPSC"). The request sought an order requiring PacifiCorp to return to Utah ratepayers certain monies collected in Utah rates for taxes, which the CCS alleges were improperly retained by PacifiCorp's then parent company, PHI. The CCS had publicly announced it was seeking a refund of at least $50.0 million to Utah ratepayers. Following PacifiCorp's sale to MEHC in March 2006, the CCS, MEHC and intervening party Utah Industrial Energy Consumers filed with the UPSC an agreement settling the claims made by the CCS. The settlement agreement was approved by the UPSC, which dismissed the CCS request. In exchange for dismissal of the claims, MEHC agreed to contribute to PacifiCorp, at no cost, MEHC's 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. PacifiCorp also agreed to expand its Blundell Geothermal Plant by 11 MW and consider a further 25 MW if economically feasible. The 11 MW expansion is in progress; however, the 25 MW expansion was determined in 2007 to not be economically feasible, and notice thereof was provided to the settlement parties and the UPSC.

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of $1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit Court of Appeals and briefing was completed in March 2006. Any final order will be subject to appeal. PacifiCorp believes the outcome of this proceeding will not have a material impact on its financial results.

In April 2004, PacifiCorp filed a complaint with the federal district court in Wyoming challenging the Wyoming Public Service Commission (the "WPSC") decision made in March 2003 to deny recovery of the Hunter No. 1 replacement power costs and certain deferred excess net power costs. The complaint was filed on the grounds that the decision violates federal law by denying PacifiCorp recovery in retail rates of its wholesale electricity and transmission costs incurred to serve Wyoming customers. In February 2006, PacifiCorp and certain parties intervening in its then-pending Wyoming general rate case reached a settlement of the terms of PacifiCorp's general rate case request. PacifiCorp also agreed to dismiss its federal lawsuit challenging the WPSC decision. The case was dismissed in May 2006.

In December 2004, a group of Utah customers filed a petition with the UPSC on behalf of themselves and other similarly situated customers seeking monetary compensation from PacifiCorp as a result of a severe winter storm in December 2003. This petition was substantially similar to an April 2004 petition that the UPSC resolved by consolidating customer requests with an ongoing regulatory winter storm inquiry. In May 2006, PacifiCorp reached a stipulation with the petitioners that resolved all claims in consideration of system maintenance and vegetation management commitments and additional credits for customers. The stipulation was approved by the UPSC on May 22, 2006.

Federal Regulatory Matters

The Bonneville Power Administration Residential Exchange Program

The Northwest Power Act, through the Residential Exchange Program, provides access to the benefits of low-cost federal hydroelectricity to the residential and small-farm customers of the region's investor-owned utilities. The program is administered by the Bonneville Power Administration (the "BPA") in accordance with federal law. Pursuant to agreements between the BPA and PacifiCorp, benefits from the BPA are passed through to PacifiCorp's Oregon, Washington and Idaho residential and small-farm customers in the form of electricity bill credits. In October 2000, PacifiCorp entered into a settlement agreement with the BPA that provided Residential Exchange Program benefits to PacifiCorp's customers from October 2001 through September 2006. In May 2004, PacifiCorp, the BPA and other parties executed an additional agreement that provides for a guaranteed range of benefits to customers from October 2006 through September 2011.

Several publicly owned utilities, cooperatives and the BPA's direct-service industry customers filed lawsuits against the BPA with the United States Ninth Circuit Court of Appeals seeking review of certain aspects of the BPA's Residential Exchange Program, as well as challenging the level of benefits previously paid to investor-owned utility customers. On May 3, 2007, the United States Ninth Circuit Court of Appeals issued two decisions. The first decision sets aside the October 2000 Residential Exchange Program settlement agreement as being inconsistent with the BPA's settlement authority. The second decision holds, among other things, that the BPA acted contrary to law when it allocated to its preference customers, which includes public utilities, cooperatives and federal agencies, part of the costs of the October 2000 settlement the BPA reached with its investor-owned utility customers. These United States Ninth Circuit Court of Appeals' decisions could affect the amount of benefits passed on to PacifiCorp's customers. Because these benefits are passed through to PacifiCorp's customers, the outcome of this matter is not expected to have a significant effect on PacifiCorp's consolidated financial results. There are several other lawsuits challenging certain aspects of the BPA's Residential Exchange Program pending at the United States Ninth Circuit Court of Appeals for which the outcomes remain unknown.

FERC Market Oversight

FERC Order No. 890

In February 2007, the FERC issued Order No. 890 adopting a final rule designed to strengthen the pro forma open access transmission tariff by providing greater specificity and increasing transparency. The most significant revisions to the pro forma open access transmission tariff relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and to exempt intermittent generators, and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service, and generation re-dispatch. As a transmission provider with an open-access transmission tariff on file with the FERC, PacifiCorp will be required to comply with the requirements of the new rule. Certain details related to the rule, such as the precise methodology that will be used to calculate available transfer capability, will be determined prospectively and, therefore, it is difficult to make a precise determination of the effect of this new rule on PacifiCorp's transmission operations. In addition, it is difficult to determine the effect of this new rule, once fully implemented, on the availability and price of transmission service from the perspective of the wholesale marketing function. However, at least on a preliminary basis, the rule is not anticipated to have a significant impact on PacifiCorp's financial results, but it will likely have a significant impact on its transmission operations, planning and wholesale marketing functions.

Energy Policy Act of 2005
On August 8, 2005, the Energy Policy Act was signed into law and has significantly impacted the energy industry. In particular, the law expanded the FERC's regulatory authority in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority to issue civil penalties of up to $1 million per day. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act, the full impact of those decisions remains uncertain.

The Energy Policy Act also gives the FERC "backstop" transmission siting authority and directs the FERC to oversee the establishment of mandatory transmission reliability standards. The Energy Policy Act also extended the federal production tax credit for new renewable electricity generation projects through December 31, 2008. Partly as a result of that portion of the law, PacifiCorp began development efforts to add additional wind-powered generation facilities.

The Energy Policy Act also requires state regulatory commissions to consider adopting a set of five new standards under the Public Utilities Regulatory Policy Act (PURPA). The standards address: (1) net metering, (2) fossil fuel diversity, (3) fossil fueled generating efficiency, (4) smart metering and (5) small generation interconnection to distribution voltage facilities. PacifiCorp's state commissions are currently in various stages of their review of these five standards.

Transmission Settlement
In January 2007, the FERC approved a settlement with PacifiCorp regarding PacifiCorp's use of its transmission system while conducting wholesale power transactions with third parties. PacifiCorp discovered possible violations of its FERC-approved tariff during an internal investigation of its compliance with certain FERC regulations shortly before MEHC's acquisition of PacifiCorp. Upon completion of the acquisition, PacifiCorp self-reported the potential violations to the FERC. The potential violations primarily related to the way PacifiCorp used its own transmission system to transmit energy using "network service" instead of "point-to-point" service as the FERC believes is required by PacifiCorp's tariff. This use of transmission service neither enriched PacifiCorp's shareholders nor harmed its retail customers. As part of the settlement, PacifiCorp voluntarily refunded $0.9 million to other transmission customers in April 2006 and paid a $10.0 million fine to the United States Treasury in January 2007.

FERC Market Power Analysis
Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. In February 2005, PacifiCorp submitted a joint triennial market power analysis, which indicated that PacifiCorp failed to pass one of the generation market power screens. In May 2005, the FERC issued an order instituting a proceeding pursuant to Section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. In June and July 2005, PacifiCorp and its formerly affiliated co-applicants submitted additional information and analysis to the FERC to rebut the presumption that PacifiCorp had generation market power.

In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. In June 2006, the FERC issued an order finding that PacifiCorp does not have market power and terminated the proceeding. In February 2007, FERC approved a change in filing status, relating to new generation, reaching the same conclusion.

California Refund Case
On April 11, 2007, PacifiCorp executed a settlement and release of claims agreement ("Settlement") with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission (collectively, the "California Parties"), certain of which purchased energy in the California Independent System Operator ("ISO") and the California Power Exchange ("PX") markets during past periods of high energy prices in 2000 and 2001. The Settlement, filed with FERC on April 11, 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the "FERC Proceedings"), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 1, 2000, through June 20, 2001 (the "Refund Period"). Under the Settlement, PacifiCorp made a cash payment to escrows controlled by the California Parties in the amount of $16 million on April 30,

2007, and upon FERC approval of the agreement, PacifiCorp will allow the PX to release an additional $12 million to such escrows, which represents PacifiCorp's estimated unpaid receivables from transactions in the PX and ISO markets during the Refund Period, plus interest. The monies held in the escrows will, upon FERC acceptance of the settlement, be distributed to buyers of power from the ISO and PX markets during the Refund Period. Other buyers in the ISO and PX markets will be provided the option of joining in the Settlement, in which case they will receive payments from one of the escrows. The agreement provides for the release of claims by the California Parties (as well as additional parties that join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief. As PacifiCorp previously accrued for these items, the settlement did not materially impact PacifiCorp's financial results.

Hydroelectric Relicensing

Klamath hydroelectric project – (Klamath River, Oregon and California)

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW nameplate-rated Klamath hydroelectric project in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license granted by the FERC and expects to continue to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp expects to continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement in Spring 2007, after which other federal agencies will complete their endangered species analyses. The states of Oregon and California will need to issue water quality certifications prior to the FERC issuing a final license.

Lewis River hydroelectric projects – (Lewis River, Washington)

PacifiCorp filed new license applications for the 136.0-MW nameplate-rated Merwin and 240.0-MW nameplate-rated Swift No. 1 hydroelectric projects in April 2004. An application for a new license for the 134.0-MW nameplate-rated Yale hydroelectric project was filed with the FERC in April 1999. However, consideration of the Yale application was delayed pending filing of the Merwin and Swift No. 1 applications so that the FERC could complete a comprehensive environmental analysis.

In November 2004, PacifiCorp executed a comprehensive settlement agreement with 25 other parties including state and federal agencies, Native American tribes, conservation groups, and local government and citizen groups to resolve, among the parties, issues related to the pending applications for new licenses for PacifiCorp's Merwin, Swift No. 1 and Yale hydroelectric projects. As part of this settlement agreement, PacifiCorp agreed to implement certain protection, mitigation and enhancement measures prior to and during a proposed 50-year license period. However, these commitments are contingent on ultimately receiving licenses from the FERC that are consistent with the settlement agreement and other required permits. PacifiCorp has received water quality certificates and a biological opinion from the United States Fish and Wildlife Service. PacifiCorp is expecting a biological opinion from the National Marine Fisheries Service in summer 2007. The FERC is expected to make a final decision no earlier than the second quarter of 2007.

Prospect hydroelectric project – (Rogue River, Oregon)

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric projects, whose nameplate ratings total 37-MW. The Oregon Department of Environmental Quality issued a 401 Water Quality Certificate for the project in April 2007, which effectively concludes the license process. FERC is expected to issue a new Order before the end of May 2007.

Hydroelectric Decommissioning

Powerdale hydroelectric project – (Hood River, Oregon)

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6.0-MW nameplate-rated Powerdale plant rather than pursue a new license, based on an analysis of the costs and benefits of relicensing versus decommissioning. Removal of the Powerdale plant and associated project features, which is subject to the FERC and other regulatory approvals, is projected to cost $5.9 million excluding inflation. Removal of the plant is scheduled to commence in 2010. However, in November 2006, flooding damaged the Powerdale plant and rendered its generating capabilities inoperable. In February 2007, the FERC granted PacifiCorp's request to cease generation at the project until decommissioning activities begin. Also in February 2007, PacifiCorp submitted a request to the FERC to allow the company to defer the remaining net book value and any additional removal costs of this project as a regulatory asset. PacifiCorp is awaiting the FERC's reply. In addition to seeking FERC approval, PacifiCorp has filed with all of its six state commissions for the authorization to defer the costs of decommissioning the Powerdale plant. PacifiCorp has also filed in all states except California for the authorization to transfer the remaining net book value of the plant from electric plant in service to a regulatory asset.

Condit hydroelectric project – (White Salmon River, Washington)

In September 1999, a settlement agreement to remove the 9.6-MW nameplate-rated Condit hydroelectric project was signed by PacifiCorp, state and federal agencies and non-governmental organizations. Under the original settlement agreement, removal was expected to begin in October 2006, with a total cost to decommission not to exceed $17.2 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal will not begin until October 2008 for a total cost to decommission not to exceed $20.5 million, excluding inflation. The settlement agreement is contingent upon receiving an amended FERC license and removal order that is not materially inconsistent with the amended settlement agreement and other regulatory approvals. PacifiCorp is in the process of acquiring all necessary permits, within the terms and conditions of the amended settlement agreement.

Cove hydroelectric project – (Grace, Idaho)

In May 2006, the FERC approved PacifiCorp's application to amend the Bear River license and authorized the removal of the 7.5-MW nameplate-rated Cove hydroelectric plant and facilities. Decommissioning of the Cove facilities has been completed in accordance with the license amendment and the approved removal plan. The removal of the dam, flowline and all facilities, with the exception of the powerhouse, was completed in November 2006. As of December 31, 2006, $2.8 million has been spent for the decommissioning of the Cove hydroelectric project.

State Regulatory Matters

Utah

In December 2006, the UPSC approved a stipulation settling PacifiCorp's general rate case filed in March 2006 related to increased investments in Utah due to growing demand for electricity. The stipulation calls for an annual increase of $115.0 million, or 9.95%, with $85.0 million of the increase effective December 11, 2006 and the remaining $30.0 million effective June 1, 2007. Under the terms of the stipulation, PacifiCorp has agreed not to file another rate case prior to December 11, 2007, with new rates effective no earlier than August 2008.

Oregon

In April 2007, PacifiCorp filed its annual compliance filing with the Public Utiilty Commission of Oregon ("OPUC") to update forecasted net power costs, requesting a 3.9% overall price increase, approximately $36 million, to take effect January 1, 2008. The annual filing, called the Transition Adjustment Mechanism, is due each April but will be adjusted through November 2007 based on changes to forecasted power costs, such as coal and gas prices and new contracts. PacifiCorp expects a ruling from OPUC this fall.

In September 2006, the OPUC approved a settlement agreement resolving PacifiCorp's February 2006 general rate case request related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including the maintenance of low-cost but aging power plants. Pursuant to the settlement agreement, PacifiCorp received an annual increase for non-power cost items of $33.0 million effective January 1, 2007. Also on January 1, 2007, PacifiCorp received a $10.0 million increase for power costs through its annual transition adjustment mechanism. After 2007, PacifiCorp's rates will be adjusted annually based on its expected power costs. PacifiCorp has agreed not to file a new rate case prior to September 1, 2007. If a case is filed on that date, new rates would be effective July 1, 2008.

In September 2005, the OPUC issued an order granting a general rate increase of $25.9 million, or an average increase of 3.2%, effective October 2005. The OPUC's order reduced PacifiCorp's revenue requirement by $26.6 million (and therefore denied any related further rate increase) based on the OPUC's interpretation of Oregon Senate Bill 408 as discussed below. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. In July 2006, a final order was issued by the OPUC affirming its initial application of Oregon Senate Bill 408. The order also modified the tax adjustment, resulting in an additional annual increase in PacifiCorp's revenue of $6.1 million effective July 2006, as well as granting deferred accounting for the period from October 2005 to July 2006. In September 2006, PacifiCorp filed an application for deferred accounting treatment of the remainder of the tax adjustment, pending the outcome of the permanent rulemaking for Oregon Senate Bill 408. This application was necessary to ensure that PacifiCorp is allowed the opportunity to recover any revenue shortfall related to its allocated tax expense in rates for 2006, to the extent any such revenue shortfall is not recovered through the Oregon Senate Bill 408 automatic adjustment clause. Because the result of the automatic adjustment clause will not be known until after the October 2007 tax reports are filed, PacifiCorp's application for deferred accounting of the remainder of the tax adjustment will be postponed until fall 2007.

In September 2005, Oregon's governor signed into law Oregon Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes.

Oregon Senate Bill 408 requires that PacifiCorp and other large regulated, investor-owned utilities that provided electric or natural gas service to Oregon customers file an annual tax report with the OPUC. Among other information, the tax report must contain; (i) the amount of taxes paid by the utility, or paid by the affiliated group and "properly attributed" to the regulated operations of the utility, and (ii) the amount of taxes "authorized to be collected in rates." If the OPUC determines that the amount of taxes "authorized to be collected" differs by more than $100,000 from the amount of taxes paid, in either direction, the OPUC will require the public utility to implement a rate schedule with an automatic adjustment clause resulting in an increase or decrease on customer bills. The automatic adjustment clause is applicable for years beginning on or after January 1, 2006. The first tax report that can result in a rate adjustment will be filed on or before October 15, 2007 with the resulting increase or decrease, if any, implemented in rates on or before June 1, 2008.

The final administrative rules define the amount of federal, state, and local taxes paid by the utility, or paid by the affiliated group and "properly attributed" to the regulated operations of the utility, as the lowest of: (i) the total tax liability of the affiliated group of which the utility is a member, (ii) the standalone tax liability of the utility, or (iii) the tax liability calculated using the "apportionment method." The "apportionment method" uses an evenly weighted three-factor formula premised on property, payroll and sales, with amounts for the regulated operations of the utility in the numerator and amounts for the affiliated group in the denominator, to generate an allocation factor that is applied against the tax liability of PacifiCorp's respective affiliated group in order to "apportion" part of that tax liability to the regulated operations of the utility. For federal purposes, the affiliated group of which PacifiCorp is a member is Berkshire Hathaway Inc. and its subsidiaries. For state and local purposes, the affiliated group differs based upon jurisdictional filing requirements.

As a result of the law and the final administrative rules, the tax liability of the affiliated group of which PacifiCorp is a member and the affiliated group's impact on the factor determined under the "apportionment method" may impact the amount of taxes paid and "properly attributed" to PacifiCorp. PacifiCorp cannot predict the financial results and the related impact of its federal affiliated group, Berkshire Hathaway Inc. and subsidiaries, and therefore, cannot determine the impact this law may have on its financial results.

Additionally, the calculation of "taxes authorized to be collected in rates," as defined by the OPUC, is based upon assumptions in the latest rate case(s) used to set rates for the respective financial reporting period. As such, "taxes authorized to be collected in rates" does not reflect actual tax collections. The resulting difference between actual tax collections and the amount deemed collected pursuant to Oregon Senate Bill 408 may be a benefit or detriment to PacifiCorp and cannot be reasonably predicted.

The OPUC recognizes that a potential conflict between its rules and federal Internal Revenue Code regulations could deny PacifiCorp the tax benefits of accelerated depreciation. As such, at the request of the OPUC, in December 2006 PacifiCorp and the other affected utilities filed requests for private letter rulings from the Internal Revenue Service on this issue, which may result in reconsideration of further changes to the rule or underlying law.

Oregon Senate Bill 408 cannot be used to decrease utility rates below a fair and reasonable level and the final administrative rules expressly provide that a utility may challenge any adjustment if it would result in rates that are not fair, just and reasonable resulting in confiscatory rates.

PacifiCorp continues to evaluate its legal and legislative options.

In April 2006, long-term special contracts for PacifiCorp's Klamath Basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the OPUC issued an order authorizing the transition of Klamath Basin irrigators to generally applicable cost-based rates.

Wyoming

In March 2006, the WPSC approved an agreement that settled the general rate case filed by PacifiCorp in October 2005 and a separate request filed by PacifiCorp in December 2005 to recover increased costs of net wholesale purchased power used to serve Wyoming customers. The agreement provides for an annual rate increase of $15.0 million effective March 1, 2006; an additional annual rate increase of $10.0 million effective July 1, 2006; a power cost adjustment mechanism effective July 1, 2006; and an agreement by the parties to support the principle of a forecast test year in the next general rate case application. A power cost adjustment mechanism addresses the changes in power costs occurring between rate cases, subject to threshold requirements and sharing arrangements. Power costs above or below the amounts built into rates may be recovered from or returned to customers according to the provisions in the specific power cost adjustment mechanism. Adjustments are subject to notice by the WPSC and possible intervention, challenges and adjustments by other parties.

In March 2007, the WPSC approved PacifiCorp's request to implement the proposed power cost adjustment mechanism rate increase effective April 1, 2007, subject to modification and possible refund. Originally filed in February 2007, the application requests recovery of approximately $2.8 million, or 0.73%. The filing requests recovery of a portion of excess net power costs incurred by PacifiCorp for the period July 1, 2006, through Nov. 30, 2006. PacifiCorp has reached a stipulation with the Intervenors for approximately $2.5 million, which was filed with the commission in May 2007. PacifiCorp is working on scheduling an open meeting date to get the stipulation approved.

Washington

In November 2006, Washington voters passed Initiative Measure No. 937, which modified state law to require utilities that serve more than 25,000 Washington customers to obtain at least 15 percent of their electricity from renewable resources by the year 2020. PacifiCorp is currently evaluating the impact of this legislation.

In October 2006, PacifiCorp filed a general rate case with the Washington Utilities and Transportation Commission ("WUTC") for an annual increase of $23.2 million, or 10.2%. As part of the filing, PacifiCorp proposed a Washington-only cost allocation methodology, which is based on PacifiCorp's western resources. The rate case included a five-year pilot on the proposed allocation methodology and a power cost adjustment mechanism. In its rebuttal case filed in March 2007, PacifiCorp reduced its request to $19 million. Hearings were held in March 2007 with the matter to be fully briefed by May 7, 2007. PacifiCorp anticipates that the WUTC will issue its order in summer 2007.

In May 2005, PacifiCorp filed a general rate case request with the WUTC for an increase of approximately $39.2 million annually, which was later reduced to approximately $30.0 million. In April 2006, the WUTC issued an order denying PacifiCorp's request to increase rates. The WUTC determined that application of PacifiCorp's cost allocation methodology failed to satisfy the statutory requirements that resources must benefit Washington ratepayers. PacifiCorp filed a petition for reconsideration of the order and requested an increase of not less than $11.0 million. PacifiCorp also filed a limited rate request seeking a rate increase of approximately $7.0 million, which represented a 2.99% increase in rates. In June 2006, the WUTC suspended PacifiCorp's limited rate request and consolidated the request with the general rate case. In July 2006, the WUTC issued an order denying PacifiCorp's request for reconsideration and rejecting the 2.99% limited rate request filing.

Idaho
In December 2006, the IPUC approved three applications filed by PacifiCorp in June 2006 proposing adjustments to the rates of certain Idaho customers for a total increase of $8.25 million. The applications were based on settlement agreements reached after negotiations between PacifiCorp and the respective customers and took the place of a general rate case originally planned to be filed in 2006. The first application was approved effective as of September 1, 2006 and the remaining two applications were approved effective as of January 1, 2007.

California
In December 2006, the California Public Utilities Commission (the "CPUC") approved an agreement settling PacifiCorp's general rate case originally filed in November 2005. The agreement provides for a $7.3 million annual increase in rates and a 10.6% return on equity, a dollar-for-dollar energy cost adjustment clause that allows for annual changes in the level of net power costs, a post-test year adjustment mechanism that provides for inflation-based increases to rates in 2008 and 2009, the ability to seek recovery of the California-allocable portion of major plant additions exceeding $50.0 million, and scheduled rate increases under the terms of the transition plan for Klamath irrigators.

In April 2006, long-term special contracts for PacifiCorp's Klamath Basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the CPUC approved a joint proposal for a transition to standard tariff pricing.

ITEM 10.

Related Party Transaction
According to the terms PacifiCorp's original offer letter to its former Senior Vice President and General Counsel, Andrew P. Haller, PacifiCorp made a $200,000.00 loan to Mr. Haller on May 21, 2001 for the repayment of obligations to his former employer. The loan accrued interest at the annual rate of 4.74%. The largest outstanding loan balance, including accrued interest, at any time during the twelve months ended December 31, 2006 was $55,521 at June 12, 2006. As of December 31, 2006 the loan was repaid in full.

For a further discussion on related party transactions, refer to page 122, *Notes to the Financial Statements* of this Form No. 1.

ITEM 11.

(Reserved)

ITEM 12.

Ownership by MidAmerican; Sale of PacifiCorp
On March 21, 2006, MEHC completed its purchase of all of PacifiCorp's outstanding common stock from PHI, a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006. The cash purchase price was $5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which includes both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

On July 17, 2006, PacifiCorp changed its Pacific Power and Utah Power operating trade names in Wyoming, Utah and Idaho to Rocky Mountain Power. PacifiCorp continues to operate under the trade name Pacific Power in Oregon, Washington and California.

Regional Transmission Coordination
In December 1999, the FERC encouraged all companies with transmission assets to form regional transmission organizations that would manage certain operational functions of the transmission grid and plan for necessary expansion. In response, several Northwest utilities, including PacifiCorp, formed a regional transmission entity, known as Grid West, that was intended to coordinate transmission functions in all or portions of eight western states and western Canada.

In April 2006, the Grid West board voted to dissolve the Grid West entity. This decision resulted primarily from the decision of key participants, including the Bonneville Power Administration to discontinue support and funding of Grid West efforts. To address the continuing need for some degree of regional transmission coordination, PacifiCorp and the other parties are considering smaller-scale initiatives that could provide value for customers.

Integrated Resource Plans

As required by state regulators, PacifiCorp uses Integrated Resource Plans to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The Integrated Resource Plan process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts and other factors. The Integrated Resource Plan is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. Each state commission that has Integrated Resource Plan adequacy rules judges whether the Integrated Resource Plan reasonably meets its standards and guidelines at the time the Integrated Resource Plan is filed. If the Integrated Resource Plan is found to be adequate, then it is formally "acknowledged." The Integrated Resource Plan can then be used as evidence by parties in rate-making or other regulatory proceedings.

In November 2005, PacifiCorp released an update to its 2004 Integrated Resource Plan. The updated 2004 Integrated Resource Plan identified a need for approximately 2,113.0 megawatts ("MW") of additional resources by summer 2014, to be met with a combination of thermal generation (1,936.0 MW) and load control programs (177.0 MW). PacifiCorp also planned to implement energy conservation programs of 450.0 average MW, to continue to seek procurement of 1,400.0 MW of economic renewable resources and to use wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources.

PacifiCorp files its Integrated Resource Plans on a biennial basis and expects to file its 2006 plan in May 2007. The OPUC issued a new set of integrated resource planning guidelines in January 2007, which apply to the 2006 plan. PacifiCorp is modifying its plan to accommodate the new analysis and reporting requirements. In addition, PacifiCorp is developing a resource strategy that accommodates evolving state energy policies and differences in resource preferences among the states that it serves, while still maintaining a system-wide planning focus.

Requests for Proposals

In July 2006, PacifiCorp filed its 2012 draft request for proposals under its 2004 Integrated Resource Plan with the UPSC and the OPUC. The draft request for proposals is for generation resources of between 840.0 MW and 915.0 MW to be available in 2012 through 2013. The scope of this draft request for proposals is focused on resources capable of delivering energy and capacity in or to PacifiCorp's network transmission system in PacifiCorp's eastern service territory. All transaction and resource decisions will be evaluated on a comparable least-cost and risk-balanced approach. In response to issues and concerns from stakeholders, PacifiCorp filed a revised version of the 2012 draft request for proposals in October 2006.

In January 2007, the OPUC issued an order denying the 2012 request for proposals. This denial does not preclude the issuance of the request for proposals. In December 2006, the UPSC issued an order suggesting modifications to the request for proposals. PacifiCorp filed the 2012 request for proposals in Utah for final approval in February 2007. This filing included a modification to request up to 1,700 MW to be available through 2014. Based on feedback from the Utah stakeholders, PacifiCorp filed a revised, final 2012 request for proposals in March 2007 and received final approval from the UPSC in April 2007.

Pension Protection Act of 2006

On August 17, 2006, the Pension Protection Act of 2006 (the "Pension Act") was signed into law. The Pension Act includes a requirement for qualified pension plans to be fully funded within seven years following the January 1, 2008 effective date. PacifiCorp does not anticipate any significant changes to the amount of funding previously anticipated through 2007. PacifiCorp is reviewing the impacts of the Pension Act on funding requirements for its retirement plan for 2008 and beyond. As a result of the Pension Act, PacifiCorp may be required to accelerate contributions to its retirement plan for periods after 2007 and there may be more volatility in annual contributions in the future.

Derivatives

PacifiCorp is exposed to variations in the market prices of natural gas and electricity as a result of its regulated utility operations and uses derivative instruments, including forward purchases and sales, swaps and options to manage these inherent commodity price risks.

Measurement Principles

Derivative instruments are recorded on the Comparative Balance Sheets at fair value as either assets or liabilities unless they are designated and qualify for the normal purchases and normal sales exemptions afforded by GAAP. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at future dates. PacifiCorp bases its forward price curves upon market price quotations when available and uses internally developed, modeled prices when market quotations are unavailable. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contracts.

Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and, therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, PacifiCorp's forward price curves must be estimated in other ways. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach), due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamentals forecast of expected spot prices for a commodity in a region based on modeled supply of and demand for the commodity in the region.

Classification and Recognition Methodology

The majority of PacifiCorp's contracts are either probable of recovery in rates, and therefore recorded as a regulatory net asset or liability, or are accounted for as cash flow hedges and therefore recorded as accumulated other comprehensive income. Accordingly, amounts are generally not recognized in earnings until the contracts are settled. As of December 31, 2006, PacifiCorp had $229.8 million recorded as regulatory assets and $3.3 million recorded as accumulated other comprehensive income related to these contracts on the Comparative Balance Sheets. If it becomes probable that a contract will not be recovered in rates, the amount recorded as a regulatory asset or liability will be written off and recognized in earnings. For cash flow hedges, PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in accumulated other comprehensive income will remain there until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur at which time associated deferred amounts in accumulated other comprehensive income are immediately recognized in earnings.

Fair Value of Derivatives

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* ("SFAS No. 133"), for the year ended December 31, 2006 and quantifies the reasons for the changes.

(Millions of dollars)	Net Asset (Liability) Trading	Net Asset (Liability) Non-trading	Regulatory Net Asset (Liability)	Accumulated Other Comprehensive (Loss) Income
Fair value of contracts outstanding at January 1, 2006	$ (0.2)	$ 141.8	$ (92.3)	$ -
Contracts realized or otherwise settled during the period	0.3	(170.3)	160.6	-
Change in valuation techniques	-	1.5	(1.5)	-
Change in estimate of recoverability (a)	-	-	(40.3)	(3.6)
Other changes in fair values (b)	(3.0)	(198.3)	203.3	0.3
Fair value of contracts outstanding at December 31, 2006	$ (2.9)	$ (225.3)	$ 229.8	$ (3.3)

(a) During the year ended December 31, 2006, PacifiCorp reached a new general rate case stipulation with several parties in Utah and received approval from the OPUC for a new general rate case settlement in Oregon. Utah and Oregon together account for approximately 70.4% of PacifiCorp's retail electric operating revenues. Based on management's consideration of the two new rate settlements, as well as the power cost recovery adjustment mechanisms approved in Wyoming and California earlier in 2006, PacifiCorp changed its estimate of the contracts receiving recovery in rates. Effective July 21, 2006, PacifiCorp recorded a $40.3 million decrease in net regulatory assets for previously recorded net unrealized gains related to contracts that it determined were probable of being recovered in rates with a corresponding pre-tax charge to net income of $43.9 million and a pre-tax increase to Accumulated other comprehensive income of $3.6 million.

(b) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.

PacifiCorp's valuation models and assumptions are updated daily to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The following table shows summarized information with respect to valuation techniques and contractual maturities of PacifiCorp's energy-related contracts qualifying as derivatives under SFAS No. 133 at December 31, 2006:

(Millions of dollars)	Fair Value of Contracts at Period-End Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Trading:					
Values based on quoted market prices from third-party sources	$ (3.2)	$ 0.3	$ -	$ -	$ (2.9)
Non-trading:					
Values based on quoted market prices from third-party sources	$ 34.2	$ (12.8)	$ (19.0)	$ (36.5)	$ (34.1)
Values based on models and other valuation methods	10.4	42.9	(20.5)	(224.0)	(191.2)
Total	$ 44.6	$ 30.1	$ (39.5)	$ (260.5)	$ (225.3)
Regulatory net asset (liability)	$ (39.7)	$ (30.5)	$ 39.5	$ 260.5	$ 229.8

Standardized derivative contracts that are valued using market quotations are classified as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods." Both classifications utilize market curves as appropriate for the first six years.

The following table summarizes the estimated changes in fair value of PacifiCorp's energy derivative contracts as of December 31, 2006 based upon multiplying a hypothetical 10% increase and a 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (in millions):

	Fair Value	Hypothetical Price	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2006	$ (228.2)	10% increase	$ (186.6)
		10% decrease	(269.8)

For a discussion of derivatives not described in this item, refer to *Notes to the Financial Statements – Note 8 – Risk Management and Hedging Activities* of this Form No. 1.

ITEM 13.

Officer & Director Changes
The following is an overview of the officer and director changes of PacifiCorp, for a further discussion of officer and director changes during the year refer to page 104, *Officers* and page 105, *Directors* of this Form No. 1.

On March 12, 2007, PacifiCorp's Senior Vice President, Stanley K. Watters, resigned as a director and officer, effective March 16, 2007.

Effective December 31, 2006, Mr. Haller, Senior Vice President, General Counsel and Corporate Secretary of PacifiCorp resigned as a director and executive officer of PacifiCorp.

On November 22, 2006, PacifiCorp's Senior Vice President, Richard D. Peach, resigned as a director and officer.

On August 22, 2006, PacifiCorp appointed David J. Mendez as Senior Vice President and Chief Financial Officer. Mr. Mendez succeeds Richard D. Peach, who continued as Senior Vice President, assisting in the transition, until his resignation as a director and officer in November 2006.

On September 15, 2006, PacifiCorp appointed Patrick Reiten as President of Pacific Power, a division of PacifiCorp, and elected him to PacifiCorp's Board of Directors, Mr. Reiten succeeded Stan Watters, who became Senior Vice President of PacifiCorp until his resignation in March 2007.

On May 23, 2006, Mr. Barry G. Cunningham, Senior Vice President of PacifiCorp resigned.

On March 21, 2006, Judith A. Johansen's previously announced resignation as President and Chief Executive Officer became effective, and Matthew R. Wright and Andrew N. MacRitchie each resigned as executive vice presidents.

On March 21, 2006, PacifiCorp's Board of Directors elected the following new officers:

- Gregory E. Abel, Chairman of the Board of Directors and Chief Executive Officer, PacifiCorp
- William J. Fehrman, President, PacifiCorp Energy
- A. Richard Walje, President, Rocky Mountain Power
- Stanley K. Watters, President, Pacific Power

On March 21, 2006, the Board of Directors elected PacifiCorp's Chief Financial Officer, Richard D. Peach to the position of Senior Vice President and PacifiCorp's Treasurer Bruce N. Williams to the position of Vice President and Treasurer. The Board of Directors did not re-elect Donald D. Larson, Vice President, Ernest E. Wessman, Vice President and Robert Klein, Senior Vice President as officers of PacifiCorp. Richard D. Peach, A. Richard Walje, Andrew P. Haller and Nolan E. Karras remained Directors of PacifiCorp.

On March 17, 2006, the following directors of PacifiCorp resigned, effective upon the closing of MidAmerican's acquisition of PacifiCorp:

- Barry G. Cunningham
- Stephen Dunn
- Judith A. Johansen
- Andrew N. MacRitchie
- Matthew R. Wright

On March 17, 2006, PacifiCorp's Board of Directors elected the following individuals as new directors of PacifiCorp, effective upon the closing of MidAmerican's acquisition of PacifiCorp:

- Gregory E. Abel

- Douglas L. Anderson
- William J. Fehrman
- Brent E. Gale
- Patrick J. Goodman
- A. Robert Lasich
- Mark C. Moench
- Stanley K. Watters

ITEM 14.

None

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	15,526,911,439	14,532,898,825
3	Construction Work in Progress (107)	200-201	734,457,063	594,604,038
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,261,368,502	15,127,502,863
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,408,699,464	6,129,967,945
6	Net Utility Plant (Enter Total of line 4 less 5)		9,852,669,038	8,997,534,918
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)		9,852,669,038	8,997,534,918
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)		8,945,604	7,836,483
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,231,400	1,128,545
20	Investments in Associated Companies (123)		7,695,513	16,579,182
21	Investment in Subsidiary Companies (123.1)	224-225	113,111,986	84,853,402
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)		93,958,194	90,179,747
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		7,847,422	11,053,888
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		234,925,374	504,831,076
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		465,252,693	714,205,233
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,559,447	17,694,774
36	Special Deposits (132-134)		13,969,784	10,698,954
37	Working Fund (135)		2,920	3,720
38	Temporary Cash Investments (136)		14,544,663	113,778,292
39	Notes Receivable (141)		893,754	1,028,037
40	Customer Accounts Receivable (142)		324,627,813	259,768,410
41	Other Accounts Receivable (143)		22,216,920	16,666,819
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		11,879,646	10,876,951
43	Notes Receivable from Associated Companies (145)		22,866,308	0
44	Accounts Receivable from Assoc. Companies (146)		9,933,523	2,882,277
45	Fuel Stock (151)	227	82,230,862	56,631,067
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	129,731,866	117,959,772
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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	0	0
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)		84,336,960	29,709,424
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		112,488	94,987
60	Rents Receivable (172)		1,266,047	2,571,410
61	Accrued Utility Revenues (173)		177,642,000	169,648,000
62	Miscellaneous Current and Accrued Assets (174)		0	151,667
63	Derivative Instrument Assets (175)		381,369,990	884,958,679
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		234,925,374	504,831,076
65	Derivative Instrument Assets - Hedges (176)		4,485,761	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,032,986,086	1,168,538,262
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		23,745,172	24,071,762
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	6,839,022	9,839,912
72	Other Regulatory Assets (182.3)	232	1,395,660,386	885,243,418
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,727,385	3,388,689
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)		0	0
77	Temporary Facilities (185)		36,534	134,081
78	Miscellaneous Deferred Debits (186)	233	57,976,248	65,950,331
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)		25,438,109	30,285,935
82	Accumulated Deferred Income Taxes (190)	234	819,687,478	687,255,514
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,333,110,334	1,706,169,642
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		13,684,018,151	12,586,448,055

Schedule Page: 110 Line No.: 82 Column:

At December 31, 2005, PacifiCorp kept its accounting records on a fiscal-year basis for the Securities and Exchange Commission (the "SEC") financial reporting purposes. The fiscal year end was March 31. Annual fiscal year end tax adjustments were performed in March. These adjustments result in larger changes to various tax accounts between "current year-end of quarter balances" and "prior year-end balances" in the first quarter FERC 3-Q (first quarter of the calendar year) report than in subsequent quarters.

For a further discussion on PacifiCorp's fiscal year, refer to *Notes to the Financial Statements – Note 1 – Basis of Presentation and Summary of Significant Accounting Policies* of this Form 1.

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Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [x] An Original (2) [ ] A Rresubmission	05/17/2007	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	3,417,945,896	3,308,226,675
3	Preferred Stock Issued (204)	250-251	41,463,300	41,463,300
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	0	0
7	Other Paid-In Capital (208-211)	253	223,285,229	1,973,218
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	41,288,207	41,288,207
11	Retained Earnings (215, 215.1, 216)	118-119	783,464,736	492,556,075
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	5,841,394	7,673,226
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)	-3,882,135	-8,067,964
16	Total Proprietary Capital (lines 2 through 15)		4,426,830,213	3,802,536,323
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,048,872,000	4,007,276,242
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	37,500,000	45,000,000
22	Unamortized Premium on Long-Term Debt (225)		43,717	46,435
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		5,853,708	5,397,420
24	Total Long-Term Debt (lines 18 through 23)		4,080,562,009	4,046,925,257
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		49,399,030	38,119,090
27	Accumulated Provision for Property Insurance (228.1)		1,418,669	590,161
28	Accumulated Provision for Injuries and Damages (228.2)		3,289,637	3,206,521
29	Accumulated Provision for Pensions and Benefits (228.3)		690,869,211	432,165,438
30	Accumulated Miscellaneous Operating Provisions (228.4)		47,586,470	37,929,426
31	Accumulated Provision for Rate Refunds (229)		0	377
32	Long-Term Portion of Derivative Instrument Liabilities		504,511,387	533,082,317
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		85,797,248	62,393,140
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,382,871,652	1,107,486,470
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		399,000,000	215,000,000
38	Accounts Payable (232)		396,650,693	346,405,807
39	Notes Payable to Associated Companies (233)		0	1,649,520
40	Accounts Payable to Associated Companies (234)		9,548,784	9,599,395
41	Customer Deposits (235)		23,526,476	35,286,140
42	Taxes Accrued (236)	262-263	21,123,323	27,310,489
43	Interest Accrued (237)		56,736,306	53,036,300
44	Dividends Declared (238)		520,947	520,947
45	Matured Long-Term Debt (239)		0	0

Name of Respondent PacifiCorp	This Report is: (1) [x] An Original (2) [ ] A Rresubmission	Date of Report *(mo, da, yr)* 05/17/2007	Year/Period of Report 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)		13,982,472	12,093,258
48	Miscellaneous Current and Accrued Liabilities (242)		84,647,611	68,282,282
49	Obligations Under Capital Leases-Current (243)		1,233,704	553,086
50	Derivative Instrument Liabilities (244)		612,857,273	743,246,559
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		504,511,387	533,082,317
52	Derivative Instrument Liabilities - Hedges (245)		1,186,351	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,116,502,553	979,901,466
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		10,343,762	6,546,023
57	Accumulated Deferred Investment Tax Credits (255)	266-267	61,687,940	69,608,060
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	61,791,513	61,591,991
60	Other Regulatory Liabilities (254)	278	109,982,910	198,320,601
61	Unamortized Gain on Reaquired Debt (257)		56,166	140,415
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	300,173	634,485
63	Accum. Deferred Income Taxes-Other Property (282)		2,005,573,266	1,981,854,886
64	Accum. Deferred Income Taxes-Other (283)		427,515,994	330,902,078
65	Total Deferred Credits (lines 56 through 64)		2,677,251,724	2,649,598,539
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		13,684,018,151	12,586,448,055

Schedule Page: 112 Line No.: 62 Column:

At December 31, 2005, PacifiCorp kept its accounting records on a fiscal-year basis for the Securities and Exchange Commission (the "SEC") financial reporting purposes. The fiscal year end was March 31. Annual fiscal year end tax adjustments were performed in March. These adjustments result in larger changes to various tax accounts between "current year-end of quarter balances" and "prior year-end balances" in the first quarter FERC 3-Q (first quarter of the calendar year) report than in subsequent quarters.

For a further discussion on PacifiCorp's fiscal year, refer to *Notes to the Financial Statements – Note 1 – Basis of Presentation and Summary of Significant Accounting Policies* of this Form 1.

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(Next Page is: 114)

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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	3,747,281,207	3,438,952,088		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,105,021,264	1,929,373,826		
5	Maintenance Expenses (402)	320-323	352,406,626	311,914,442		
6	Depreciation Expense (403)	336-337	390,945,206	372,668,587		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	47,633,759	48,011,207		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,479,353	5,479,353		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		1,674,863	1,256,147		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		7,696,523	6,307,820		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	101,034,471	96,297,630		
15	Income Taxes - Federal (409.1)	262-263	106,778,946	95,781,130		
16	- Other (409.1)	262-263	9,090,310	7,878,018		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	813,769,788	690,441,169		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	753,579,201	623,891,591		
19	Investment Tax Credit Adj. - Net (411.4)	266	-5,854,860	-5,854,860		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)			60,094		
22	(Less) Gains from Disposition of Allowances (411.8)		15,619,250	16,224,770		
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)		3,166,477,798	2,919,498,202		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		580,803,409	519,453,886		

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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
3,747,281,207	3,438,952,088					2
						3
2,105,021,264	1,929,373,826					4
352,406,626	311,914,442					5
390,945,206	372,668,587					6
						7
47,633,759	48,011,207					8
5,479,353	5,479,353					9
1,674,863	1,256,147					10
						11
7,696,523	6,307,820					12
						13
101,034,471	96,297,630					14
106,778,946	95,781,130					15
9,090,310	7,878,018					16
813,769,788	690,441,169					17
753,579,201	623,891,591					18
-5,854,860	-5,854,860					19
						20
	60,094					21
15,619,250	16,224,770					22
						23
						24
3,166,477,798	2,919,498,202					25
580,803,409	519,453,886					26

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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)		580,803,409	519,453,886		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,443,913	3,532,054		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,554,683	3,164,391		
33	Revenues From Nonutility Operations (417)		156,069	850,397		
34	(Less) Expenses of Nonutility Operations (417.1)		23,117	15,559		
35	Nonoperating Rental Income (418)		60,059	41,539		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-1,831,832	839,244		
37	Interest and Dividend Income (419)		7,426,781	7,876,811		
38	Allowance for Other Funds Used During Construction (419.1)		23,612,825	9,915,057		
39	Miscellaneous Nonoperating Income (421)		480,231,577	396,466,451		
40	Gain on Disposition of Property (421.1)		162,550	1,142,752		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		509,684,142	417,484,355		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		342,567	650,349		
44	Miscellaneous Amortization (425)	340	1,099,117	629,194		
45	Donations (426.1)	340	2,144,714	1,948,545		
46	Life Insurance (426.2)		-7,657,632	-3,129,019		
47	Penalties (426.3)		10,058,546	220,420		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,163,251	1,031,555		
49	Other Deductions (426.5)		530,547,357	355,829,911		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		537,697,920	357,180,955		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	497,588	211,423		
53	Income Taxes-Federal (409.2)	262-263	24,842,659	20,365,661		
54	Income Taxes-Other (409.2)	262-263	3,371,372	2,060,382		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	95,532,620	1,262,019		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	134,566,999	882,563		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		2,065,260	2,065,260		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-12,388,020	20,951,662		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-15,625,758	39,351,738		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		245,313,780	237,603,134		
63	Amort. of Debt Disc. and Expense (428)		3,779,288	3,911,956		
64	Amortization of Loss on Reaquired Debt (428.1)		4,847,826	6,116,695		
65	(Less) Amort. of Premium on Debt-Credit (429)		2,718	2,718		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		84,249	85,275		
67	Interest on Debt to Assoc. Companies (430)	340	25,955	473,493		
68	Other Interest Expense (431)	340	26,043,696	26,579,047		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		22,680,215	16,966,931		
70	Net Interest Charges (Total of lines 62 thru 69)		257,243,363	257,629,401		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		307,934,288	301,176,223		
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)		307,934,288	301,176,223		

Schedule Page: 114 Line No.: 6 Column: c

Vehicle depreciation is charged to functional accounts. The following table summarizes the vehicle depreciation expense that was charged to the functional accounts.

	Twelve Months Ending December 31, 2006	Twelve Months Ending December 31, 2005
Vehicle Depreciation	$ 12,268,419	$ 11,352,594

Schedule Page: 114 Line No.: 7 Column: c

PacifiCorp records the depreciation expense of asset retirement obligations as either a regulatory asset or (liability).

Schedule Page: 114 Line No.: 14 Column: c

Payroll taxes are charged to functional accounts, which is consistent with where labor is charged. The following table summarizes the payroll tax expense that was charged to the functional accounts.

	Twelve Months Ending December 31, 2006	Twelve Months Ending December 31, 2005
Payroll Tax Expense	$ 36,613,788	$ 35,422,794

Schedule Page: 114 Line No.: 15 Column: d

At December 31, 2005, PacifiCorp kept its accounting records on a fiscal-year basis for the Securities and Exchange Commission (the "SEC") financial reporting purposes. The fiscal year end was March 31. Annual fiscal year end tax adjustments were performed in March. These adjustments result in larger changes to various tax accounts between "current year-end of quarter balances" and "prior year-end balances" in the first quarter FERC 3-Q (first quarter of the calendar year) report than in subsequent quarters.

For a further discussion on PacifiCorp's fiscal year, refer to *Notes to the Financial Statements – Note 1 – Basis of Presentation and Summary of Significant Accounting Policies* of this Form 1.

Schedule Page: 114 Line No.: 16 Column: d

See footnote on page 114, line 15, column (d).

Schedule Page: 114 Line No.: 17 Column: d

See footnote on page 114, line 15, column (d).

Schedule Page: 114 Line No.: 18 Column: d

See footnote on page 114, line 15, column (d).

Schedule Page: 114 Line No.: 24 Column: c

PacifiCorp records the accretion expense of asset retirement obligations as either a regulatory asset or (liability).

Schedule Page: 114 Line No.: 53 Column: d

See footnote on page 114, line 15, column (d).

Schedule Page: 114 Line No.: 54 Column: d

See footnote on page 114, line 15, column (c).

Schedule Page: 114 Line No.: 55 Column: d

See footnote on page 114, line 15, column (c).

Schedule Page: 114 Line No.: 56 Column: d

See footnote on page 114, line 15, column (c).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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		488,980,264	1,066,638,637
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)		309,766,120	300,336,979
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	Preferred Stock - Various Series and rates	238	-2,083,790	(2,083,790)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-2,083,790	(2,083,790)
30	Dividends Declared-Common Stock (Account 438)			
31	Common stock	238	-16,773,669	(206,524,304)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-16,773,669	(206,524,304)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			(669,387,258)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		779,888,925	488,980,264
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)		3,575,811	3,575,811
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,575,811	3,575,811
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		783,464,736	492,556,075
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		7,673,226	(662,613,084)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-1,831,832	839,244
51	(Less) Dividends Received (Debit)			
52	Transfer to Unappropriated Retained Earnings (Account 216)			669,447,066
53	Balance-End of Year (Total lines 49 thru 52)		5,841,394	7,673,226

Schedule Page: 118 Line No.: 37 Column: d

As previously reported in PacifiCorp's Form 3-Q for the nine months ended September 30, 2005, $669.4 million was transferred from Account 216.1 to Account 216 following a review of 18 CFR 101.216 and 216.1. This transfer between accounts had no impact on total retained earnings and except for the individual balances of Accounts 216 and 216.1, had no effect on the Comparative Balance Sheet or Statement of Retained Earnings. This transfer had no effect on the Statement of Income or Statement of Cash Flows.

Schedule Page: 118 Line No.: 52 Column: d

See footnote on page 118, line 37, column (d).

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(Next Page is: 120)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	307,934,288	301,176,223
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	403,735,798	384,308,603
5	Amortization of	63,583,615	61,683,721
6			
7	Unrealized (Gains)/Losses on Derivative Contracts	51,066,157	-42,795,968
8	Deferred Income Taxes (Net)	21,156,209	66,929,034
9	Investment Tax Credit Adjustment (Net)	-7,920,120	-7,920,120
10	Net (Increase) Decrease in Receivables	-82,840,925	25,540,192
11	Net (Increase) Decrease in Inventory	-37,371,890	-20,893,280
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	116,660,014	41,755,843
14	Net (Increase) Decrease in Other Regulatory Assets	14,522,865	82,487,911
15	Net Increase (Decrease) in Other Regulatory Liabilities	-3,472,833	-20,254,639
16	(Less) Allowance for Other Funds Used During Construction	23,612,825	9,915,057
17	(Less) Undistributed Earnings from Subsidiary Companies	-1,831,832	839,244
18	Amounts Due To/From Affiliates, Net	-52,647,096	32,529,623
19	Other operating activities:	-36,872,203	7,747,688
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	735,752,886	901,540,530
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,339,383,764	-984,446,581
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-23,612,825	-9,915,057
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,315,770,939	-974,531,524
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	309,662	3,651,413
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-38,211,124	-682,333
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)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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		
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)	-7,854,645	-10,196,012
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,361,527,046	-981,758,456
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	348,333,528	295,914,826
62	Preferred Stock		
63	Common Stock	109,722,222	374,992,877
64	Equity Contribution	216,766,877	
65			
66	Net Increase in Short-Term Debt (c)	182,634,965	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	857,457,592	670,907,703
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-310,552,000	-173,234,000
74	Preferred Stock	-7,500,000	-7,500,000
75	Common Stock		
76	Inter-Company Borrowings (Note Agreement)	-1,595,907	-18,877,300
77	Repayment of Capital Lease Obligations	-547,822	
78	Net Decrease in Short-Term Debt (c)		-70,102,322
79			
80	Dividends on Preferred Stock	-2,083,790	-2,083,790
81	Dividends on Common Stock	-16,773,669	-206,524,304
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	518,404,404	192,585,987
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-107,369,756	112,368,061
87			
88	Cash and Cash Equivalents at Beginning of Period	131,476,786	19,108,725
89			
90	Cash and Cash Equivalents at End of period	24,107,030	131,476,786

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

	YTD Dec. 31, 2006	YTD Dec. 31, 2005	FERC Account
Amortization of Software Development & Other Intangibles	$ 47,633,759	$ 48,011,207	404
Amortization of Licensing/Hydro	1,099,117	629,194	425
Amortization of Electric Plant Acq. Adj. - Common	5,479,353	5,479,353	406
Amortization of Regulatory Assets/Liabilities	9,371,386	7,563,967	407 / 407.3 / 407.4
	$ 63,583,615	$ 61,683,721	

Schedule Page: 120 Line No.: 19 Column: a

	YTD Dec. 31, 2006	YTD Dec. 31, 2005	FERC Account
Coal Depreciation & Depletion included in Cost of Fuel	$ 13,481,495	$ 12,354,940	151
PMI Equity Earnings eliminated in Cost of Fuel	(11,269,409)	(14,715,240)	501
(Gain)/Loss on Sale of Property	(127,201)	(1,364,968)	254 / 411.6 / 411.7
Deferred Credits - Deferred Compensation	(1,232,359)	-	253.4 / 253.41
Accumulated Provision for Pension & Benefits	(33,547,909)	1,696,634	228
Write-Off of Assets Under Construction	1,598,165	4,227,101	107
Share Based Compensation Expense & Section 199	(1,275,241)	1,973,218	211
Accum Provision For Mining / Environ / Decom	(7,075,262)	3,409,456	228 / 253
Other	2,575,518	166,547	Various
	$ (36,872,203)	$ 7,747,688	

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

	YTD Dec. 31, 2006	YTD Dec. 31, 2005	FERC Account
Other Investments/Special Funds	$ (256,759)	$ (5,397,030)	124 / 128
Temporary Facilities	97,548	(74,971)	185
Restricted Cash	(2,521,392)	(4,724,011)	128 / 134
Business Acquisition of Steam Reserve Corporation	(5,174,041)	-	101
	$ (7,854,645)	$ (10,196,012)	

Schedule Page: 120 Line No.: 64 Column: a

	YTD Dec. 31, 2006	YTD Dec. 31, 2005	FERC Account
Equity Contribution received from MEHC	$ 214,950,000	$ -	211
Contribution received from MEHC from the acquition of IGC	2,330,669	-	211
Other equity adjustments	(513,792)	-	211
Net Additional Paid-In Capital	$ 216,766,877	$ -	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.

PACIFICORP
NOTES TO THE FINANCIAL STATEMENTS

Note 1 – Organization and Operations

PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electric utility company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal-mining facilities and services and steam delivery facilities.

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006. The cash purchase price was $5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which includes both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

Note 2 – Summary of Significant Accounting Policies

Basis of Presentation

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("the FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include specific information requested by the FERC and are generally similar to the GAAP reporting requirements unless otherwise noted.

The following are the significant differences between FERC reporting standards and GAAP:

Investments in Subsidiaries
PacifiCorp accounts for certain investments in subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries as required by GAAP. GAAP requires that majority-owned subsidiaries and variable-interest entities for which a company is the primary beneficiary be consolidated in accordance with Statement of Financial Accounting Standards ("SFAS") No. 94, *Consolidation of All Majority-Owned Subsidiaries* and revised Financial Accounting Standards Board (the "FASB") Interpretation No. 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51.* In general, the accounting for investments in these certain subsidiaries using the equity method rather than the consolidation method in accordance with GAAP has no effect on net income or retained earnings.

Accumulated Removal Costs
The accumulated removal costs for PacifiCorp's regulated plant assets that do not meet the definition of an asset retirement obligation under SFAS No. 143, *Accounting for Asset Retirement Obligations*, are classified as a regulatory liability under GAAP and as accumulated depreciation under FERC.

Accumulated Deferred Income Taxes
Accumulated deferred income taxes are classified as current and non-current for GAAP, by presenting net current assets and liabilities separate from net non-current assets and liabilities on the balance sheet in accordance with SFAS No. 109, *Accounting for Income Taxes.* All such amounts are classified as gross non-current assets and gross non-current liabilities for FERC.

Unrealized Gains and Losses on Derivative Instruments
FERC requires that unrealized gains and losses on derivative instruments be classified gross on the income statement in accordance with FERC Order 627, *Accounting and Reporting of Financial Instruments, Comprehensive Income, Derivatives and Hedging Activities.* Unrealized gains on wholesale sales, purchased power and fuel are reported in Miscellaneous nonoperating income and unrealized losses on wholesale sales, purchased power and fuel are reported in Other deductions. For GAAP

reporting purposes, unrealized gains and losses on wholesale sales are reported in Revenues and unrealized gains and losses on purchased power and fuel are reported in Energy costs and Operations and maintenance expense.

Reclassifications
Certain other reclassifications of balance sheet, income statement and cash flow amounts have been made in order to conform to a FERC basis of presentation. These reclassifications had no effect on net income.

Change in Fiscal Year

On May 10, 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. See PacifiCorp's Securities and Exchange Commission (the "SEC") Transition Report on Form 10-K for the nine months ended December 31, 2006 for consolidated financial statements and complete footnotes prepared in accordance with GAAP.

Use of Estimates in Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. These estimates include, but are not limited to: unbilled receivables; valuation of energy contracts; the effects of regulation; the accounting for contingencies, including environmental and regulatory matters; and certain assumptions made in accounting for pension and postretirement benefits. Actual results may differ from the estimates used in preparing the Financial Statements.

Cash Equivalents

Cash equivalents consist of funds invested in commercial paper, money market securities and in other investments with a maturity of three months or less when purchased.

(Millions of dollars)	December 31, 2006	December 31, 2005
Cash (131)	$ 9.6	$ 17.7
Working funds (135)	-	-
Temporary cash investments (136)	14.5	113.8
Total cash and cash equivalents	$ 24.1	$ 131.5

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PacifiCorp has deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based rate-making to another form of regulation; other regulatory actions; or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. If it becomes probable that these costs will not be recovered, the assets and liabilities would be written off and recognized in income from operations.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the outcome of pending disputes, arbitrations and the ability of customers to pay the amounts owed to PacifiCorp. The allowance activity was as follows:

	Years Ended December 31,	
(Millions of dollars)	2006	2005
Beginning balance	$ 10.9	$ 18.9
Charged to costs and expenses, net	10.3	9.6
Write-offs, net	(9.3)	(17.6)
Ending balance	$ 11.9	$ 10.9

Derivatives

PacifiCorp employs a number of different derivative instruments in connection with its electric and natural gas, foreign currency exchange rate and interest rate risk management activities, including forward purchases and sales, swaps and options. Derivative instruments are recorded in the Comparative Balance Sheet at fair value as either assets or liabilities unless they are designated and qualifying for the normal purchases and normal sales exemptions afforded by GAAP.

For all hedge contracts, PacifiCorp maintains formal documentation of the hedge. In addition, at inception and on a quarterly basis, PacifiCorp formally assesses whether the hedge contracts are highly effective in offsetting changes in cash flows of the hedged items. PacifiCorp documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualifying as a cash flow hedge, to the extent effective, are included in the Statements of Accumulated Comprehensive Income, Comprehensive Income, and Hedging Activities, net of tax, until the hedged item is recognized in income. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in Accumulated other comprehensive income will remain in Accumulated other comprehensive income until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in Accumulated other comprehensive income are immediately recognized in earnings.

Certain derivative contracts utilized by PacifiCorp are recoverable through rates. Accordingly, unrealized changes in fair value of these contracts are deferred as regulatory net assets or liabilities pursuant to SFAS No. 71.

Derivative contracts for commodities used in PacifiCorp's normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases and normal sales pursuant to the exemptions provided by GAAP. Recognition of these contracts in Revenue or Operations expense in the Statement of Income occurs when the contracts settle.

When available, quoted market prices or prices obtained through external sources are used to measure a contract's fair value. For contracts without available quoted market prices, fair value is determined based on internally developed modeled prices.

Inventories

Inventories consist mainly of materials and supplies, coal stocks and fuel oil, which are valued at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Property, plant and equipment are recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor costs and contract services, as well as indirect construction costs, which include allowance for funds used during construction. The cost of major additions and betterments are capitalized, while costs for replacements, maintenance, and repairs that do not improve or extend the lives of the respective assets are charged to operating expense.

When PacifiCorp retires its regulated property, plant and equipment, it charges the original cost and the cost of removal and salvage to accumulated depreciation. Generally, when depreciable regulated assets are sold, the cost is removed from the property accounts and the related accumulated depreciation and amortization accounts are reduced and any residual gain or loss is amortized through depreciation rates in the future.

PacifiCorp records an allowance for funds used during construction, which represents the estimated cost of debt and equity costs of capital funds necessary to finance capital additions. Allowance for funds used during construction is capitalized as a component of Property, plant and equipment, with offsetting credits to the Statement of Income. After construction is completed, PacifiCorp is permitted to earn a return on these costs by their inclusion in rate base, as well as recover these costs through depreciation expense over the useful life of the related assets.

The weighted-average aggregate rates used for the allowance for funds used during construction were 7.7% for the year ended December 31, 2006 and 5.7% for the year ended December 31, 2005. PacifiCorp's allowance for funds used during construction rates do not exceed the maximum allowable rates determined by regulatory authorities.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on Intangible plant was $358.4 million at December 31, 2006 and $341.2 at December 31, 2005. Amortization expense on Intangible plant was $45.7 million for the year ended December 31, 2006 and $46.4 million for the year ended December 31, 2005. The estimated aggregate amortization on Intangible plant for the years ending December 31, 2007 through 2011 is $44.4 million in 2007, $36.7 million in 2008, $29.2 million in 2009, $25.5 million in 2010 and $23.2 million in 2011. Unamortized computer software costs were $177.2 million at December 31, 2006 and $188.9 million at December 31, 2005.

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from other regulated utilities over their net book value in those assets. These unallocated acquisition adjustments had an original cost of $157.2 million and accumulated depreciation of $79.9 million at December 31, 2006.

Asset Retirement Obligations

PacifiCorp recognizes legal asset retirement obligations, mainly related to the final reclamation of leased coal-mining property. The fair value of a liability for a legal asset retirement obligation is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of the liability is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to Property, plant and equipment) and for accretion of the liability due to the passage of time. The difference between the asset retirement obligations liability, the corresponding asset retirement obligations asset included in Property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability. Estimated removal costs that PacifiCorp recovers through approved depreciation rates but that do not meet the requirements of a legal asset retirement obligations are accumulated in Accumulated provision for depreciation in the Comparative Balance Sheet.

Depreciation and Amortization

Depreciation and amortization are computed by the straight-line method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. Composite depreciation rates of average depreciable assets on utility Property, plant and equipment (excluding amortization of capital leases) were 3.0% for each of the years ended December 31, 2006 and 2005.

The average depreciable lives of Property, plant and equipment currently in use by category are as follows:

Generation	
Steam plant	20 – 43 years
Hydroelectric plant	14 – 85 years
Wind projects	20 – 25 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

Computer software costs included in Intangible plant are initially assigned a depreciable life of 5 to 10 years.

Revenue Recognition

Revenue from customers is recognized as electricity is delivered and includes amounts for services rendered. Amounts recognized include unbilled as well as billed amounts. Rates charged are subject to federal and state regulation.

Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type.

Certain taxes assessed by governmental authorities on revenue-producing transactions are collected directly from PacifiCorp's customers and remitted directly to taxing authorities. This collection and remittance activity is recorded on a net basis and thus has no income statement impact.

Income Taxes

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway Inc. commenced including PacifiCorp in its U.S. federal income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns. Prior to the sale, PacifiCorp was included in PHI's consolidated U.S. federal income tax return.

Deferred tax assets and liabilities are based on differences between the financial statements and tax bases of assets and liabilities using the estimated tax rates in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of Other comprehensive income are charged or credited directly to Other comprehensive income. Otherwise, changes in deferred income tax assets and liabilities are included as a component of income tax expense.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $416.2 million as of December 31, 2006, and will be included in rates when the temporary differences reverse. Management believes the existing regulatory assets are probable of recovery. If it becomes probable that these costs will not be recovered, the assets would be written off and recognized in earnings.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

In determining PacifiCorp's tax liabilities, management is required to interpret complex tax laws and regulations. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through 2000. Although the ultimate resolution of PacifiCorp's federal and state tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse effect on PacifiCorp's financial condition, results of operations or cash flows. PacifiCorp's provision for tax uncertainties is included in current and accrued assets or liabilities in the Comparative Balance Sheet.

Segment Information

PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric utility operations.

New Accounting Standards

FERC Order No. 668

In December 2005, FERC issued order 668, *Accounting and Financial Reporting for Public Utilities Including RTOs* ("FERC Order No. 668"). The main purpose of FERC Order No. 668 is to establish new accounting and reporting requirements for regional transmission organizations. However, the order also establishes new accounts and reporting for certain transmission activities for non-regional transmission organization public utilities. This order was effective April 1, 2006. The issuance of this order did not have a material impact to PacifiCorp's financial position or results of operations.

FIN 47

In March 2005, the Financial Accounting Standards Board (the "FASB") issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143* ("FIN 47"). FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Upon adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of $22.7 million, increased net depreciable assets by $1.8 million and increased regulatory assets by $20.9 million.

EITF No. 04-6

On April 1, 2006, PacifiCorp adopted the Emerging Issues Task Force (the "EITF") issued EITF No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* ("EITF No. 04-6"). EITF No. 04-6 requires that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (that is, extracted) during the period that the stripping costs are incurred. The adoption of EITF No. 04-6 did not have a material impact on PacifiCorp's financial position or results of operations.

FIN 48

In July 2006, the Financial Accounting Standards Board (the "FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes– an interpretation of FASB Statement No. 109* ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in accordance with SFAS No. 109, *Accounting for Income Taxes*, and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Guidance is also provided on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective on January 1, 2007. PacifiCorp is currently evaluating the impact and based upon its assessment to date does not believe the adoption of FIN 48 will have a material effect on its financial position and results of operations.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 157 on its financial position and results of operations.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"). SFAS No. 158 requires an employer to recognize an asset or liability for the over- or underfunded status of a defined benefit postretirement plan measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plan, such as a retiree healthcare plan, the benefit obligation is the accumulated postretirement benefit obligation. SFAS No. 158 also requires entities to recognize as a component of other comprehensive income, net of tax, the actuarial gains and losses and the prior service costs and credits that arise during the period, but that were not recognized as components of net periodic benefit cost of the period pursuant to SFAS No 87, *Employers' Accounting for Pensions* ("SFAS No. 87"), and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* ("SFAS No. 106"). However, as PacifiCorp is subject to SFAS No. 71, it recognized as regulatory assets substantially all amounts that would have been otherwise charged to other comprehensive income including the tax effect of any additional recovery expected from regulatory treatment. SFAS No. 158 does not impact the calculation of net periodic benefit cost and the amounts recognized in either Accumulated other comprehensive income or as a regulatory asset will be adjusted as they are subsequently recognized as components of net periodic benefit cost pursuant to the recognition and amortization provisions of SFAS No. 87 and SFAS No. 106.

PacifiCorp adopted the recognition and related disclosure provisions of SFAS No. 158 as of December 31, 2006. The incremental impacts of such adoption to the Comparative Balance Sheet as of December 31, 2006 are as follows:

(Millions of dollars)	Before SFAS No. 158	Increase (Decrease)	After SFAS No. 158
Deferred income taxes	$ 654.7	$ 165.0	$ 819.7
Regulatory assets	1,054.4	341.3	1,395.7
Miscellaneous deferred debits	71.8	(13.8)	58.0
Total assets	13,191.5	492.5	13,684.0
Accumulated provision for pensions and benefits	325.6	365.3	690.9
Miscellaneous current and accrued liabilities	80.6	4.0	84.6
Deferred income taxes	2,308.9	124.5	2,433.4
Total liabilities	8,763.4	493.8	9,257.2
Accumulated other comprehensive income	(2.6)	(1.3)	(3.9)
Total shareholders' equity	4,428.1	(1.3)	4,426.8

SFAS No. 158 also requires that an employer measure plan assets and obligations as of the end of the employer's fiscal year, eliminating the option in SFAS No. 87 and SFAS No. 106 to measure up to three months prior to the financial statement date. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end is not required until fiscal years ending after December 15, 2008. PacifiCorp did not adopt the measurement date provisions of the statement during the year ended December 31, 2006. Upon adoption of the measurement date provisions, PacifiCorp will be required to record a transitional adjustment to retained earnings or to a regulatory asset depending on whether the amount is considered probable of being recovered in rates.

For GAAP reporting purposes, the adoption of SFAS No. 158 was not reflected as a component of other comprehensive income during the period, but rather as a component of the ending balance of accumulated other comprehensive income. For FERC reporting purposes, the adoption of SFAS No. 158 was presented as a component of other comprehensive income during the period, as well as a component of the ending balance of accumulated other comprehensive income.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, Including* *an Amendment to SFAS No. 115* ("SFAS No. 159"). SFAS No. 159 permits entities to elect to measure many financial instruments and certain other items at fair value. Upon adoption of SFAS No. 159, an entity may elect the fair value option for eligible items that exist at the adoption date. Subsequent to the initial adoption, the election of the fair value option should only be made at initial recognition of the asset or liability or upon a remeasurement event that gives rise to new-basis accounting. The decision about whether to elect the fair value option is applied on an instrument-by-instrument basis, is irrevocable and is applied only to an entire instrument and not only to specified risks, cash flows or portions of that instrument. SFAS No. 159 does not affect any existing accounting standards that require certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. PacifiCorp is currently evaluating the impact of adopting SFAS No. 159 on its financial position and results of operations.

Note 3 - Regulatory Assets and Liabilities

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. At present, PacifiCorp is subject to cost-based rate-making for its business. PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is, therefore, subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters. PacifiCorp had regulatory assets not earning a return on investment of $1,269.3 million at December 31, 2006. For a detailed view of PacifiCorp's regulatory assets and liabilities see page 232, *Regulatory Assets* and page 278, *Regulatory Liabilities* of this FERC Form 1.

Note 4 – Short-Term Borrowings

Short-Term Debt

PacifiCorp's outstanding short-term borrowings consisted of commercial paper arrangements of $399.0 million at an average interest rate of 5.3% at December 31, 2006 and $215.0 million at an average interest rate of 4.3% at December 31, 2005.

Revolving Credit Agreement

PacifiCorp has an $800.0 million unsecured revolving credit facility expiring in July 2011. The credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate (LIBOR), plus 0.195%, that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities, and it supports PacifiCorp's commercial paper program. At December 31, 2006, there were no borrowings outstanding under this facility.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. At December 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

Note 5 - Long-Term Debt, Preferred Stock Subject to Mandatory Redemption and Capital Lease Obligations

PacifiCorp's long-term debt, preferred stock subject to mandatory redemption and capital lease obligations were as follows:

	December 31			
	2006		2005	
(Millions of dollars)	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds				
4.3% to 9.2%, due through 2011	$ 1,277.8	6.6 %	$ 1,588.4	6.5 %
5.0% to 8.8%, due 2012 to 2016	457.0	5.6	457.0	5.6
8.4% to 8.5%, due 2017 to 2021	21.7	8.5	21.7	8.5
6.7% to 8.3%, due 2022 to 2026	404.0	7.4	404.0	7.4
7.7% due 2031	300.0	7.7	300.0	7.7
5.3% to 6.1%, due 2032 to 2036	850.0	5.8	500.0	5.5
Unamortized discount	(5.3)		(4.9)	
Guaranty of pollution-control revenue bonds				
Variable rates, due 2013 (a) (b)	40.7	4.0	40.7	3.8
Variable rates, due 2014 to 2025 (b)	325.2	3.9	325.2	3.6
Variable rates, due 2024 (a) (b)	175.8	4.0	175.8	3.7
3.4% to 5.7%, due 2014 to 2025 (a)	184.0	4.5	184.0	4.5
6.2%, due 2030	12.7	6.2	12.7	6.2
Unamortized discount	(0.5)		(0.5)	
Funds held by trustees	-		(2.2)	
Total long-term debt	$ 4,043.1		$ 4,001.9	
Other long-term debt				
Preferred stock subject to mandatory redemption, due 2007	$ 37.5		$ 45.0	
Total other long-term debt	$ 37.5		$ 45.0	
Capital lease obligations				
10.4% to 14.8%, due through 2036	50.6	11.7	38.7	11.7
Total capital lease obligations	$ 50.6		$ 38.7	
Total	$ 4,131.2		$ 4,085.6	

(a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately $14.6 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage at December 31, 2006.

In September 2005, the Securities and Exchange Commission declared effective PacifiCorp's shelf registration statement covering $700.0 million of future first mortgage bond and unsecured debt issuances. During February 2007, PacifiCorp filed a shelf registration statement with the SEC covering an additional $800.0 million of first mortgage bond and unsecured debt issuances. This registration statement was declared effective by the SEC.

As of December 31, 2006, $2.7 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2006, $541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par. As of
December 31, 2006, $71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par and another $12.7 million at 102.0% of par. The remaining long-term debt was not redeemable at December 31, 2006.

In August 2006, PacifiCorp issued $350.0 million of its 6.10% Series of First Mortgage Bonds due August 1, 2036.

At December 31, 2006, PacifiCorp had $517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately $21.0 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available at December 31, 2006 and expire periodically through February 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants and default provisions to those contained in PacifiCorp's revolving credit agreement, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and at December 31, 2006, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that expire at various dates through October 2036 for transportation services, real estate and for the use of certain equipment which qualify as capital leases. The transportation services agreements included as capital leases are for the right to use newly constructed pipeline facilities to provide natural gas to two of PacifiCorp's power plants. Non-cash additions to property, plant and equipment related to these capital leases were $12.6 million during the year ended December 31, 2006 and $12.4 million during the year ended December 31, 2005. Assets accounted for as capital leases of $49.3 million as of December 31, 2006 and $36.7 million as of December 31, 2005 were included in Utility plant on the Comparative Balance Sheet.

PacifiCorp's Preferred stock subject to mandatory redemption was as follows:

(Thousands of shares, millions of dollars)	December 31, 2006		December 31, 2005	
Series	Shares	Amount	Shares	Amount
No Par Serial Preferred, 16,000 shares authorized				
$100 stated value				
$7.48	375	$ 37.5	450	$ 45.0

All outstanding shares are subject to mandatory redemption on June 15, 2007. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights. PacifiCorp redeemed $7.5 million of Preferred stock subject to mandatory and optional redemption during the years ended December 31, 2006 and 2005. Dividends declared but unpaid on Preferred stock subject to mandatory redemption that were included in Interest payable were $0.7 million at December 31, 2006 and $0.8 million at December 31, 2005.

The annual maturities of long-term debt, preferred stock subject to mandatory redemption and capital lease obligations for the years ending December 31 are:

(Millions of dollars)	Long-term Debt	Preferred Stock Subject to Mandatory Redemption	Capital Lease Obligations	Total
2007	$ 125.7	$ 37.5	$ 6.9	$ 170.1
2008	412.4	-	7.0	419.4
2009	138.5	-	7.0	145.5
2010	14.6	-	7.0	21.6
2011	586.7	-	7.0	593.7
Thereafter	2,771.0	-	91.3	2,862.3
	4,048.9	37.5	126.2	4,212.6
Unamortized discount	(5.8)	-	-	(5.8)
Amounts representing interest (a)	-	-	(75.6)	(75.6)
	$ 4,043.1	$ 37.5	$ 50.6	$ 4,131.2

(a) Interest expense on capital lease obligations is recorded as rent expense.

Note 6 – Asset Retirement Obligations

PacifiCorp records asset retirement obligation liabilities for long-lived physical assets that qualify as legal obligations. PacifiCorp estimates its asset retirement obligation liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission and distribution and other assets cannot currently be estimated and no amounts are recognized in the accompanying Financial Statements other than those included in Accumulated provision for depreciation as established in approved depreciation rates.

On March 31, 2006, PacifiCorp adopted FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*, an interpretation of FASB Statement No. 143 ("FIN 47"). FIN 47 clarifies that the term "conditional asset retirement obligation" as used in SFAS No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, PacifiCorp is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists.

In conjunction with the adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of $22.7 million, which is included in Liabilities incurred in the table below. PacifiCorp also increased net depreciable assets by $1.8 million, reclassified $13.5 million of costs accrued for removal from regulatory liabilities to asset retirement obligation liabilities, increased regulatory liabilities by $0.4 million and increased regulatory assets by $7.8 million for the difference between retirement costs approved by regulators and obligations under FIN 47.

The following table describes the changes to PacifiCorp's asset retirement obligation liability for the years ended December 31, 2006 and 2005:

(Millions of dollars)	December 31, 2006		December 31, 2005	
Liability recognized at beginning of period	$	62.4	$	66.7
Liabilities incurred		28.6		1.5
Liabilities settled		(5.4)		(10.2)
Revisions in cash flow (a)		(3.7)		1.4
Accretion expense (b)		3.9		3.0
Asset retirement obligation	$	85.8	$	62.4

(a) Results from changes in the timing and amounts of estimated cash flows for certain plant reclamation.
(b) PacifiCorp records the accretion expense of asset retirement obligations as either a regulatory asset or (liability).

Note 7 – Risk Management and Hedging Activities

PacifiCorp is directly exposed to the impact of market fluctuations in the prices of natural gas and electricity. PacifiCorp is exposed to interest rate risk as a result of the issuance of fixed and variable rate debt. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity and financial derivative instruments, including forward contracts, swaps and options. The risk management process established by PacifiCorp is designed to identify, measure, assess, report and manage each of the various types of risk involved in its business. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes. As of December 31, 2006 PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

Commodity Price Risk

PacifiCorp is exposed to market risk due to the variations in the price of fuel used for generation and the price of wholesale electricity to be purchased or sold. To manage this commodity price risk, as well as to optimize the utilization of power generation assets and related contracts, PacifiCorp enters into forward purchases and sales. Such energy purchase and sales activities are governed by PacifiCorp's risk management policy.

PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Derivative Instruments

Forward purchases and sales that do not qualify for the exemptions afforded by GAAP are accounted for as derivatives and are recorded on the Comparative Balance Sheet as assets or liabilities measured at estimated fair value. Where PacifiCorp's derivative instruments are subject to a master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts – An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the accompanying Comparative Balance Sheet. For those energy purchase and sales contracts that are probable of recovery in rates, the unrealized gains and losses on derivative instruments are recorded as a regulatory net asset or liability.

Realized gains and losses on contracts that qualify as normal purchases and normal sales under GAAP (and therefore exempted from fair value accounting) are reflected in the Statement of Income at the contract settlement date.

Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Statement of Income as Miscellaneous non-operating income. Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Statement of Income as Miscellaneous non-operating income for unrealized gains and Other deductions for unrealized losses. Realized gains and losses on physically settled derivative contracts not held for trading purposes are presented in the Statement of Income as Revenues for sales contracts and as Operating expenses for purchase contracts. Realized gains and losses on non-physically settled derivative contracts not held for trading purposes are presented on a net basis in the Statement of Income as Revenues.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Comparative Balance Sheet as of December 31, 2006:

(Millions of dollars)	Net Assets (Liability)			Regulatory Net Asset	Accumulated Other Comprehensive
	Assets	Liabilities	Total	(Liability)	Income (Loss) (a)
Commodity hedges	$ 382.5	$ (614.0)	$ (231.5)	$ 233.1	$ (3.3)
Foreign currency swaps	3.3	-	3.3	(3.3)	-
	$ 385.8	$ (614.0)	$ (228.2)	$ 229.8	$ (3.3)
Current	$ 150.9	$ (109.5)	$ 41.4		
Non-current	234.9	(504.5)	(269.6)		
Total	$ 385.8	$ (614.0)	$ (228.2)		

(a) Before income taxes.

The following table summarizes the various derivative mark-to-market positions included in the accompanying Comparative Balance Sheet as of December 31, 2005:

(Millions of dollars)	Net Assets (Liability)			Regulatory Net Asset	Accumulated Other Comprehensive
	Assets	Liabilities	Total	(Liability)	Income (Loss) (a)
Commodity hedges	$ 884.9	$ (743.3)	$ 141.6	$ (92.3)	$ -
Current	$ 380.1	$ (210.2)	$ 169.9		
Non-current	504.8	(533.1)	(28.3)		
Total	$ 884.9	$ (743.3)	$ 141.6		

(a) Before income taxes.

Cash Flow Hedging

In order to reduce the impact of fluctuations in forward prices of electricity and natural gas on PacifiCorp's results of operations, PacifiCorp initiated cash flow hedging in April 2006 for a portion of its derivative contracts, primarily electricity sales and natural gas purchase contracts. Changes in the fair value of derivative contracts designated as cash flow hedges are recorded as other comprehensive income to the extent the hedges are effective in offsetting changes in future cash flows for forecasted electricity and natural gas purchase and sales transactions. Amounts included in Accumulated other comprehensive income are reclassified to the Statement of Income when the forecasted sale or purchase transaction is recognized in earnings, or when it is probable that the forecasted transaction will not occur.

At December 31, 2006, PacifiCorp had cash flow hedges with expiration dates through December 2007. During the year ended December 31, 2006, hedge ineffectiveness was insignificant. At December 31, 2006, $3.3 million of pre-tax net unrealized gains are forecasted to be reclassified from Accumulated other comprehensive income into earnings over the next twelve months as contracts settle. Hedge ineffectiveness and reclassifications from Accumulated other comprehensive income to earnings are presented in Miscellaneous non-operating income and Other deductions.

Summary of Activity

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Statement of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates:

	Years Ended December 31,	
(Millions of dollars)	2006	2005
Revenues		
Miscellaneous nonoperating income (421)	$ (475.9)	$ (368.9)
Other income deductions:		
Other deductions (426.5)	526.9	326.2
Total unrealized (gain) loss on derivative contracts	$ 51.0	$ (42.7)

Fair Value Calculations

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market, such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

Foreign Currency Derivatives

PacifiCorp has entered into an agreement with a turbine supplier in connection with the construction of a wind project that requires PacifiCorp to make certain payments in Euros ("€"). To mitigate the related exposure to fluctuations in foreign currency exchange rates, PacifiCorp entered into a forward contract to purchase €76.8 million at a fixed price of U.S. Dollars. This contract has a series of payments and settlement dates extending to March 15, 2007 that correspond to the payments to be made in Euros in accordance with the supply agreement. The forward contract qualifies as a derivative instrument. As the cost of the associated wind project is expected to be recovered in rates, the unrealized gain on this contract of $3.3 million at December 31, 2006 was recorded as a net regulatory asset.

Weather Derivatives

PacifiCorp had a non-exchange-traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. The contract expired on September 30, 2006. PacifiCorp paid an annual premium in return for the right to make or receive payments if streamflow levels were above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net liability recorded for this contract was zero at December 31, 2006 and 2005. PacifiCorp recognized a loss of $12.4 for the year ended December 31, 2006 and a gain of $9.4 million for the year ended December 31, 2005.

Note 8 - Income Taxes

Income tax expense (benefit) consists of the following:

(Millions of dollars)	Years Ended Decmber 31, 2006	2005
Current:		
Federal	$ 131.6	$ 116.2
State	12.5	9.9
Total	144.1	126.1
Deferred:		
Federal	19.9	61.1
State	1.2	5.8
Total	21.1	66.9
Investment tax credits	(7.9)	(7.9)
Total income tax expense	$ 157.3	$ 185.1

A reconciliation of the federal statutory tax rate to the effective tax rate applicable to income before income tax expense follows:

	Years Ended December 31, 2006	2005
Federal statutory rate	35.0 %	35.0 %
State taxes, net of federal benefit	3.2	3.3
Effect of regulatory treatment of depreciation differences	3.9	3.1
Tax reserves	(2.6)	1.5
Tax credits	(3.7)	(2.2)
Other	(2.1)	(2.6)
Effective income tax rate	33.7 %	38.1 %

The net deferred tax liability consists of the following:

(Millions of dollars)	December 31, 2006	December 31, 2005
Deferred tax assets:		
Regulatory liabilities	$ 319.9	$ 330.1
Employee benefits	294.4	179.0
Derivative contracts	102.3	45.7
Other deferred tax assets	103.1	132.5
	819.7	687.3
Deferred tax liabilities:		
Property, plant and equipment	$ (1,509.5)	$ (1,518.1)
Regulatory assets	(726.9)	(647.8)
Derivative contract regulatory assets	(87.2)	-
Other deferred tax liabilities	(109.8)	(147.5)
	(2,433.4)	(2,313.4)
Net deferred tax liability	$ (1,613.7)	$ (1,626.1)

As of December 31, 2006 and 2005, PacifiCorp had no federal or state net operating loss carryforwards. PacifiCorp has Oregon business energy tax credits of approximately $3.0 million at December 31, 2006 available to reduce future income tax liabilities. These credits begin to expire in 2015. PacifiCorp has Idaho investment tax credits of approximately $2.3 million at December 31, 2006 that are available to reduce future income tax liabilities. These credits begin to expire in 2016. PacifiCorp anticipates utilizing the tax credits prior to the expiration dates.

PacifiCorp has established, and periodically reviews, an estimated contingent tax reserve on its Comparative Balance Sheet to provide for the possibility of adverse outcomes in tax proceedings. In addition, tax benefits are recognized in the period in which resolution is reached with taxing authorities. The reserve for net federal and state contingencies decreased $12.1 million during the year ended December 31, 2006. The decrease was primarily attributable to resolution of certain items previously outstanding with the Internal Revenue Service related to the examination of tax years ended March 31, 2001 through 2003. PacifiCorp anticipates that the resolution of the remaining outstanding issues related to federal income tax returns through March 31, 2003 and other unresolved issues will not have a material adverse impact on its financial results.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have occurred immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. However, no adjustments have been recorded as PacifiCorp is not yet able to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. As the transaction was deemed to be with shareholders and as a result of formal agreements among PacifiCorp, MEHC, PHI and ScottishPower, PacifiCorp does not believe any adjustments resulting from the tax effect of a deferred intercompany gain or loss will have a material impact on its financial results.

Note 9 – Preferred Stock

PacifiCorp's preferred stock, not subject to mandatory redemption, including issuance expense of $0.2 million which is included in account 214 on the Comparative Balance Sheet, was as follows:

(Thousands of shares, millions of dollars, except per share amounts) Series		Redemption Price Per Share	December 31, 2006 Shares	Amount	December 31, 2005 Shares	Amount
Serial Preferred, $100 stated value, 3,500 shares authorized						
	4.52 %	$ 103.5	2	$ 0.2	2	$ 0.2
	4.56	102.3	85	8.4	85	8.4
	4.72	103.5	70	6.9	70	6.9
	5.00	100.0	42	4.2	42	4.2
	5.40	101.0	66	6.6	66	6.6
	6.00	Non-redeemable	6	0.6	6	0.6
	7.00	Non-redeemable	18	1.8	18	1.8
5% Preferred, $100 stated value, 127 shares authorized		110.0	126	12.6	126	12.6
			415	$ 41.3	415	$ 41.3

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of voluntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all preferred stock is entitled to stated value plus accrued dividends. Any premium paid on redemptions of preferred stock is capitalized, and recovery is sought through future rates. Dividends on all preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

Dividends declared but unpaid on preferred stock were $0.5 million at December 31, 2006 and $0.5 million at December 31, 2005.

Note 10 - Common Shareholder's Equity

Appropriated Retained Earnings

At December 31, 2006, PacifiCorp had $3.6 million in Appropriated retained earnings - amortization reserve, federal in accordance with the requirements of certain hydroelectric relicensing projects.

Common Shareholder's Equity

PacifiCorp has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 357,060,915 shares were issued and outstanding at December 31, 2006 and 347,158,187 shares issued and outstanding at December 31, 2005.

During the nine months ended December 31, 2006 and while under the control of its then direct parent company PPW Holdings, LLC, PacifiCorp received equity contributions of $215.0 million in cash from PPW Holdings LLC.

During the three months ended March 31, 2006, PacifiCorp issued 9,902,728 shares of its common stock to PHI, its former parent company, at a total price of $109.7 million.

During the year ended December 31, 2005, PacifiCorp issued 34,982,098 shares of its common stock to PHI, its former parent company, at a total price of $375.0 million.

Common Dividend Restrictions

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of December 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to either PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. At December 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 4 and 5.

Note 11 - Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines and penalties in substantial amounts.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a compliant against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Clean Air Act's opacity standards at PacifiCorp's Jim Bridger Power Plant in Wyoming. Under the Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light in the flue of a generating facility. The complaint alleges thousands of violations and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per violation, and the plaintiffs' costs of litigation. PacifiCorp believes it has a number of defenses to the claims, and it has already committed to invest at least $812.0 million in pollution control equipment at its generating facilities, including the Jim Bridger plant, that is expected to significantly reduce emissions. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time.

Environmental Matters

PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act, related air quality standards promulgated by the Environmental Protection Agency and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws have the potential for impacting PacifiCorp's operations. Specifically, the Clean Air Act will likely continue to impact the operations of PacifiCorp's generating facilities and will likely require PacifiCorp to reduce emissions from those facilities through the installation of additional or improved emission controls, the purchase of additional emission allowances, or some combination thereof. As of December 31, 2006, PacifiCorp's environmental contingencies principally consist of air quality matters. Pending or proposed air regulations would, if enacted, require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxide and other pollutants at its generating plants below current levels. PacifiCorp believes it is in material compliance with current environmental requirements.

PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement, PacifiCorp's proportionate share and any coverage provided by insurance policies. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing costs of PacifiCorp. The liability recorded was $19.9 million at December 31, 2006 and $13.5 million at December 31, 2005 and is included in Deferred credits on the accompanying Comparative Balance Sheet. The December 31, 2006 recorded liability included $2.5 million of discounted liabilities. Had none of the liabilities included in the $19.9 million balance recorded at December 31, 2006 been discounted, the total would have been $20.5 million. The expected payments for each of the years ending December 31, 2007 through 2011 and thereafter are as follows: $1.9 million in 2007, $1.7 million in 2008, $1.5 million in 2009, $0.4 million in 2010, $0.4 million in 2011 and $14.6 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately $10.9 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's financial position, results of operations or cash flows.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 50 plants with an aggregate plant net owned capacity of 1,160.1 MW. The FERC regulates 97.9% of the net capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing with the FERC. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $79.0 million in costs at December 31, 2006 for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Comparative Balance Sheet.

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169.0-MW nameplate-rated Klamath hydroelectric project in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue to operate under annual licenses until the new operating license is issued. As part of the relicensing process, the United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006, which proposed that PacifiCorp construct upstream and downstream fish passage facilities at the Klamath hydroelectric project's four mainstem dams. In April 2006, PacifiCorp filed alternatives to the federal agencies' proposal and requested an administrative hearing to challenge some of the federal agencies' factual assumptions supporting their proposal for the construction of the fish passage facilities. A hearing was held in August 2006 before an administrative law judge. The administrative law judge issued a ruling in September 2006 generally supporting the federal agencies' factual assumptions. In January 2007, the United States Departments of Interior and Commerce filed modified terms and conditions consistent with March 2006 filings and rejected the alternatives proposed by PacifiCorp. PacifiCorp is prepared to meet and implement the federal agencies' terms and conditions as part of the project's relicensing. However, PacifiCorp will continue in settlement discussions with various parties in the Klamath Basin area who have intervened with the FERC licensing proceeding to try to achieve a mutually acceptable outcome for the project.

Also, as part of the relicensing process, the FERC is required to perform an environmental review. In September 2006, the FERC issued its draft environmental impact statement on the Klamath hydroelectric project license. The public comment period on the draft environmental impact statement closed on December 1, 2006. The FERC is expected to issue its final environmental impact statement in spring 2007, after which other federal agencies will complete their endangered species analyses. The states of Oregon and California will need to issue water quality certifications prior to the FERC issuing a final license.

In the relicensing of the Klamath project, PacifiCorp has incurred $42.1 million in costs at December 31, 2006, which are reflected in Construction work-in-progress in the accompanying Comparative Balance Sheet. While the costs of implementing new license provisions cannot be determined until such time as a new license is issued, such costs could be material.

FERC Issues

California Refund Case

On April 11, 2007, PacifiCorp executed a settlement and release of claims agreement ("Settlement") with Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, the People of the State of California, ex rel. Edmund G. Brown Jr., Attorney General, the California Electricity Oversight Board, and the California Public Utilities Commission (collectively, the "California Parties"), certain of which purchased energy in the California Independent System Operator ("ISO") and the California Power Exchange ("PX") markets during past periods of high energy prices in 2000 and 2001. The Settlement, filed with FERC on April 11, 2007, settles claims brought by the California Parties against PacifiCorp for refunds and remedies in numerous related proceedings (together, the "FERC Proceedings"), as well as certain potential civil claims, arising from events and transactions in Western United States energy markets during the period January 1, 2000, through June 20, 2001 (the "Refund Period"). Under the Settlement, PacifiCorp made a cash payment to escrows controlled by the California Parties in the amount of $16 million on April 30, 2007, and upon FERC approval of the agreement, PacifiCorp will allow the PX to release an additional $12 million to such escrows, which represents PacifiCorp's estimated unpaid receivables from transactions in the PX and ISO markets during the Refund Period, plus interest. The monies held in the escrows will, upon FERC acceptance of the settlement, be distributed to buyers of power from the ISO and PX markets during the Refund Period. Other buyers in the ISO and PX markets will be provided the option of joining in the Settlement, in which case they will receive payments from one of the escrows. The agreement provides for the release of claims by the California Parties (as well as additional parties that join in the Settlement) against PacifiCorp for refunds, disgorgement of profits, or other monetary or non-monetary remedies in the FERC Proceedings, and provides a mutual release of claims for civil damages and equitable relief. As PacifiCorp previously accrued for these items, the settlement did not materially impact PacifiCorp's financial results.

Note 12 – Guarantees and Other Commitments

Guarantees

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. The following represent the indemnification obligations of PacifiCorp at December 31, 2006.

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp agreed to indemnify Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of $10.1 million until October 2008 and a cap of $5.1 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

Unconditional Purchase Obligations

(Millions of dollars)	Payments due during the 12 months ending December 31, 2007	2008	2009	2010	2011	Thereafter	Total
Construction	$ 312.6	$ 24.4	$ 4.1	$ 0.6	$ -	$ -	$ 341.7
Operating leases	14.8	8.4	3.5	3.0	2.9	20.2	52.8
Purchased electricity	701.7	385.0	358.1	314.3	243.4	1,889.0	3,891.5
Transmission	66.5	54.2	60.2	54.3	48.9	482.4	766.5
Fuel	567.1	515.0	498.8	366.7	216.1	1,213.9	3,377.6
Other	255.1	87.5	97.0	136.9	48.4	635.6	1,260.5
Total unconditional purchase obligations	$1,917.8	$1,074.5	$1,021.7	$875.8	$559.7	$4,241.1	$9,690.6

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At December 31, 2006, PacifiCorp had estimated long-term unconditional purchase obligations for construction of the new natural gas fueled Lake Side Power Plant.

Operating leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the years ending December 31, 2092. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense, including that related to obligations accounted for as capital leases for balance sheet presentation, was $25.5 million for the year ended December 31, 2006 and $29.4 million for the year ended December 31, 2005.

Minimum non-cancelable sublease rent payments expected to be received through the years ended December 31, 2017 total $20.2 million.

Purchased electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Energy costs in the Statement of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At December 31, 2006, PacifiCorp's share of long-term arrangements with public utility districts was as follows:

(Millions of dollars) Generating Facility	Year Contract Expires	Nameplate (MW)	Percentage of Output	Annual Costs (a)
Wanapum	2009	194.1	18.7 %	$ 7.6
Rocky Reach	2011	67.8	5.3	3.9
Priest Rapids	2045	62.1	6.5	2.7
Wells	2018	53.4	6.9	2.7
Total		377.4		$ 16.9

(a) Includes debt service totaling $9.1 million.

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the years ending December 31 are as follows:

(Millions of dollars)	Minimum Debt Service	Operating Obligations
2007	$ 11.4	$ 8.6
2008	11.3	8.8
2009	11.3	8.9
2010	5.3	5.2
2011	5.3	5.3
Thereafter	73.2	93.5
	$ 117.8	$ 130.3

PacifiCorp has a 4.0% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4.0% entitlement of the Intermountain Power Project at a price equivalent to 4.0% of the expenses and debt service of the project.

Fuel
PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Other
Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements.

Note 13 - Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides healthcare and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors an employee savings plan.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp's plans. This separation resulted in a net $3.5 million reduction in Common shareholder's equity during the year ended December 31, 2006.

Pension and Other Postretirement Plans

PacifiCorp's pension plans include the Retirement Plan (the "Retirement Plan"), the Supplemental Executive Retirement Plan (the

"SERP") and joint trust plans to which PacifiCorp contributes on behalf of certain bargaining units. Benefits under the Retirement Plan are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

In December 2006, non-bargaining employees were notified that PacifiCorp is switching from a traditional final average pay formula for the Retirement Plan to a cash balance formula effective June 1, 2007. Benefits under the final average pay formula will be frozen as of May 31, 2007, with no further benefit accrual under that formula. All future benefits will be earned under the cash balance formula. The changes are expected to result in a significant reduction in Pension and other post employment liabilities and Regulatory assets.

The cost of other postretirement benefits, including healthcare and life insurance benefits for eligible retirees, is accrued over the active service period of employees. PacifiCorp funds other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust plans for postretirement benefits offered to certain bargaining units.

During May 2006, the PacifiCorp board of directors elected to change its fiscal year end from March 31 to December 31. As plan assets and obligations are measured three months prior to PacifiCorp's fiscal year end, plan assets were measured as of September 30 in the current year and as of December 31 in the prior periods. The following disclosures were generally taken directly from PacifiCorp's Form 10-K filed with the SEC in March 2007 and thus disclose activity between the above-mentioned measurement dates.

Net periodic benefit cost for the pension and other postretirement plans included the following components:

	Pension			Other Postretirement		
	Nine Months Ended December 31,	Years Ended March 31,		Nine Months Ended December 31,	Years Ended March 31,	
(Millions of dollars)	2006	2006	2005	2006	2006	2005
Service cost (a)	$ 22.6	$ 30.8	$ 25.9	$ 6.7	$ 8.8	$ 8.5
Interest cost	56.4	74.4	73.8	24.6	30.4	31.0
Expected return on plan assets (b)	(54.3)	(76.9)	(77.7)	(19.3)	(26.3)	(26.4)
Amortization of unrecognized net transition obligation	2.0	8.4	8.4	9.0	12.2	12.2
Amortization of unrecognized prior service cost	0.8	1.2	1.4	2.1	2.1	0.1
Amortization of unrecognized loss	19.9	21.5	8.5	4.4	2.7	0.6
Cost of termination benefits	1.8	3.0	-	-	-	-
Curtailment loss	0.7	-	-	-	-	-
Net periodic benefit cost (c)	$ 49.9	$ 62.4	$ 40.3	$ 27.5	$ 29.9	$ 26.0

(a) Service cost excludes $6.4 million of contributions to the joint trust plans for the nine months ended December 31, 2006 and $1.4 million for the year ended March 31, 2006. There were no contributions to the joint trust plans for the year ended March 31, 2005.

(b) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur. As differences between expected and actual investment returns are recognized, they are included in the Amortization of unrecognized loss component of Net periodic benefit cost.

(c) Net periodic benefit cost for the three months ended March 31, 2006 was $16.8 million for the pension plans and $7.5 million for the other postretirement plans, resulting in total net periodic benefit cost for the year ended December 31, 2006 of $66.7 million for the pension plans and $35.0 million for the other postretirement plans.

The following table is a reconciliation of the fair value of plan assets as of the end of the period:

	Pension		Other Postretirement	
(Millions of dollars)	December 31, 2006	March 31, 2006	December 31, 2006	March 31, 2006
Plan assets at fair value at beginning of period	$ 824.9	$ 806.5	$ 292.1	$ 286.6
Employer contributions	79.3	63.8	29.9	22.5
Participant contributions	-	-	6.9	8.3
Actual return on plan assets	55.4	72.6	18.9	20.4
Benefits paid	(75.7)	(84.1)	(29.4)	(41.6)
Separation of former participants	-	(32.0)	-	(4.1)
Transfers	-	(1.9)	-	-
Plan assets at fair value at end of period	$ 883.9	$ 824.9	$ 318.4	$ 292.1

The SERP has no plan assets, and accordingly, the fair value of the plan assets was zero as of December 31, 2006 and March 31, 2006. Although the SERP had no assets, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Although the SERP liabilities are included in the table below, because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $38.6 million at December 31, 2006 and $36.4 million at March 31, 2006.

The following table is a reconciliation of the benefit obligation at the end of the period:

	Pension		Other Postretirement	
(Millions of dollars)	December 31, 2006	March 31, 2006	December 31, 2006	March 31, 2006
Benefit obligation, beginning of period	$ 1,342.2	$ 1,338.1	$ 582.4	$ 528.3
Service cost	22.6	30.8	6.7	8.8
Interest cost	56.4	74.4	24.6	30.4
Participant contributions	-	-	6.9	8.3
Plan amendments	-	2.9	-	22.8
Actuarial (gain) loss	(14.4)	22.9	(24.9)	34.3
Benefits paid	(75.7)	(84.1)	(29.4)	(41.6)
Cost of termination benefits	1.8	3.0	-	-
Separation of former participants	-	(44.3)	-	(8.9)
Transfers	-	(1.5)	-	-
Benefit obligation, end of period	$ 1,332.9	$ 1,342.2	$ 566.3	$ 582.4
Accumulated benefit obligation as of the measurement date	$ 1,164.9	$ 1,170.9	$ -	$ -

The portion of the pension plans' projected benefit obligation, included in the table above, related to the SERP was $53.5 million at December 31, 2006 and $52.3 million at March 31, 2006. The SERP's accumulated benefit obligation totaled $53.2 million at December 31, 2006 and $50.5 million at March 31, 2006.

As of December 31, 2006 the funded status of the pension and other postretirement plans was recorded in the Comparative Balance Sheet as required under the adoption of SFAS No. 158. Balance sheet amounts recorded as of March 31, 2006 did not include the unrecognized net actuarial losses, prior service costs and net transition obligations of $452.9 million for the pension plans and $241.3 million for the other postretirement plans. However, an additional minimum pension liability of $281.6 million was recorded for the pension plans as of March 31, 2006. The combined funded status of the plans and the net liability recognized in the accompanying Comparative Balance Sheet is as follows:

(Millions of dollars)	Pension December 31, 2006	Pension March 31, 2006	Other Postretirement December 31, 2006	Other Postretirement March 31, 2006
Plan assets at fair value, end of period	$ 883.9	$ 824.9	$ 318.4	$ 292.1
Less - Benefit obligation, end of period	1,332.9	1,342.2	566.3	582.4
Funded status	(449.0)	(517.3)	(247.9)	(290.3)
Unrecognized actuarial losses and other	-	452.9	-	241.3
Contribution made after measurement date but before year-end	-	3.7	27.3	29.7
Net liability recognized in the Consolidated Balance Sheets	$ (449.0)	$ (60.7)	$ (220.6)	$ (19.3)
Net amounts recognized in the Consolidated Balance Sheets consist of:				
Regulatory assets	$ -	$ 257.7	$ -	$ -
Deferred charges and other assets:				
Intangible assets	-	17.3	-	-
Other current liabilities	(4.0)	-	-	-
Pension and other post employment liabilities	(445.0)	(342.3)	(220.6)	(19.3)
Accumulated other comprehensive loss, pre-tax	-	6.6	-	-
Net liability recognized in the Consolidated Balance Sheets	$ (449.0)	$ (60.7)	$ (220.6)	$ (19.3)
Amounts not yet recognized as components of net periodic benefit cost:				
Net losses	$ 400.1	$ 435.6	$ 109.2	$ 138.1
Prior service cost	8.5	10.0	19.9	22.1
Net transition obligation	5.3	7.3	72.2	81.1
Total	$ 413.9	$ 452.9	$ 201.3	$ 241.3
SFAS No. 158 amounts have been recorded as follows based upon expected recovery in rates:				
Regulatory assets	$ 404.9		$ 161.0	
Deferred income taxes	-		39.8	
Accumulated other comprehensive loss, before tax	9.0		0.5	
Total	$ 413.9		$ 201.3	

As of March 31, 2006, the net liability recognized for the pension plans was comprised of accrued pension cost of $60.7 million and an additional minimum pension liability of $281.6 million, which resulted in a total accrued benefit liability of $342.3 million for the pension plans. The table above reconciles the total accrued benefit liability to the accrued pension cost as of March 31, 2006 by presenting the offsetting effects of the additional minimum pension liability in Regulatory assets, Intangible assets and Accumulated other comprehensive loss.

The net loss, prior service cost and net transition obligation that will be amortized from the above amounts in 2007 into net periodic benefit cost are estimated to be as follows:

(Millions of dollars)	Net Losses	Prior Service Cost	Net Transition Obligation	Total
Pension benefits	$ 27.1	$ 1.1	$ 2.6	$ 30.8
Other postretirement benefits	4.5	2.8	12.0	19.3
Total	$ 31.6	$ 3.9	$ 14.6	$ 50.1

Plan Assumptions

Assumptions used to determine benefit obligations and net benefit cost were as follows:

	Pension			Other Postretirement		
	Nine Months Ended December 31,	Years Ended March 31,		Nine Months Ended December 31,	Years Ended March 31,	
	2006	2006	2005	2006	2006	2005
Benefit obligation as of the measurement date:						
Discount rate	5.85 %	5.75 %	5.75 %	6.00 %	5.75 %	5.75 %
Rate of compensation increase	4.00	4.00	4.00	N/A	N/A	N/A
Net benefit cost for the period ended:						
Discount rate	5.75 %	5.75 %	6.25 %	5.75 %	5.75 %	6.25 %
Expected return on plan assets	8.50	8.75	8.75	8.50	8.75	8.75
Rate of compensation increase	4.00	4.00	4.00	N/A	N/A	N/A

Assumed health care cost trend rates as of the measurement date:

	Nine Months Ended December 31,	Years Ended March 31,	
	2006	2006	2005
Health care cost trend rate assumed for next year - under 65	10.0 %	10.0 %	7.5 %
Health care cost trend rate assumed for next year - over 65	8.0	10.0	9.5
Rate that the cost trend rate gradually declines to	5.0	5.0	5.0
Year that rate reaches the rate it is assumed to remain at - under 65	2012	2011	2007
Year that rate reaches the rate it is assumed to remain at - over 65	2010	2011	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	Increase (Decrease) in Expense	
(Millions of dollars)	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 2.5	$ (1.9)
Effect on other postretirement benefit obligation	42.0	(34.4)

Contributions and Benefit Payments

PacifiCorp expects to contribute approximately $88.0 million to the pension plans and $33.7 million to the other postretirement plan for 2007.

PacifiCorp's expected benefit payments to participants for its pension and other postretirement plans for 2007 through 2011 and for the five years thereafter are summarized below:

(Millions of dollars)

		Projected Benefit Payments		
		Other Postretirement		
Years ending December 31,	Pension	Gross	Medicare Subsidy	Net of Subsidy
2007	$ 89.3	$ 40.1	$ 3.3	$ 36.8
2008	90.6	42.0	3.7	38.3
2009	94.1	43.8	4.1	39.7
2010	98.5	45.4	4.4	41.0
2011	103.3	47.3	4.7	42.6
2012 to 2016 (inclusive)	568.9	261.7	30.3	231.4

Investment Policy and Asset Allocation

Retirement Plan and other postretirement plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that primarily uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of primarily equity, fixed-income and other alternative investments as shown in the table below. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the pension account. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies.

PacifiCorp's asset allocation was as follows:

	Pension & Other Postretirement			Voluntary Employees' Beneficiaries Association Trust		
	December 31, 2006	March 31, 2006	Target	December 31, 2006	March 31, 2006	Target
Equity securities	58.0 %	58.5 %	i3.0 - 57.0 %	65.3 %	66.0 %	53.0 - 65.0 %
Debt securities	34.6	34.5	35.0	34.7	34.0	35.0
Other	7.4	7.0	8.0 - 12.0	N/A	N/A	0.0 - 12.0

Defined Contribution Plan

PacifiCorp's employee savings plan qualifies as a tax-deferred arrangement under the Internal Revenue Code. Participating employees may defer up to 50.0% of their compensation, subject to certain statutory limitations, and can select a variety of investment options. PacifiCorp matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation, with the company match vesting over the initial five years of an employee's qualifying service. Thereafter, PacifiCorp's contributions vest immediately. PacifiCorp may also make an additional contribution equal to a percentage of the employee's eligible earnings, which are immediately vested. PacifiCorp's contributions to the Savings Plan were $21.1 million for the year ended December 31, 2006 and $21.5 million for the year ended December 31, 2005.

In December 2006, PacifiCorp communicated to its non-bargaining employees that effective June 1, 2007, PacifiCorp will match 65.0% of employee contributions on amounts deferred up to 6.0% of total compensation.

Severance

PacifiCorp has undertaken a review of its organization and workforce. As a result of the review, PacifiCorp incurred severance expense of $42.8 million during the year ended December 31, 2006 compared to $5.1 million during the year ended December 31, 2005.

Note 14 - Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. In addition, the carrying amount of variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates.

The fair value of PacifiCorp's fixed-rate long-term debt, current maturities of long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities.

The following table presents the carrying amount and estimated fair value of the named financial instruments as of December 31, 2006:

(Millions of dollars)	Carrying Amount	Fair Value
Long-term debt (a)	$ 4,043.1	$ 4,243.3
Preferred stock subject to mandatory redemption	37.5	37.9

(a) Includes long-term debt classified as currently maturing, less capital lease obligations.

Note 15 – Related-Party Transactions

Transactions while owned by MEHC

As discussed in Note 1, PacifiCorp was acquired by a subsidiary of MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

As a result of a settlement agreement between MEHC, the Utah Committee of Consumer Services and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controlled 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Intermountain Geothermal Company therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC. During the year ended December 31, 2006, PacifiCorp acquired an additional 25.2% of the steam rights associated with the geothermal field.

In the ordinary course of business, PacifiCorp engages in various transactions with several of its affiliated companies. Services provided by PacifiCorp and charged to affiliates related primarily to the administrative services, financial statement preparation and direct-assigned employees. These receivables were $0.6 million at December 31, 2006. Services provided by affiliates and charged to PacifiCorp related primarily to the transport of natural gas with Kern River Gas Transmission Company and administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These payables were $0.7 million at December 31, 2006. These expenses totaled $7.8 million for the year ended December 31, 2006.

Effective March 21, 2006, PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves, but as a result of regulatory commitments are capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2007. Prepayments to MISL were $1.6 million at December 31, 2006. Receivables for claims were $8.2 million at December 31, 2006. Premium expenses were $5.7 million for the year ended December 31, 2006.

As of December 31, 2006, Prepayments included $43.5 million of income taxes receivable.

Transactions with Unconsolidated Subsidiaries of PacifiCorp

In the ordinary course of business, PacifiCorp engages in various transactions with its unconsolidated subsidiaries. Services provided by PacifiCorp and charged to its subsidiaries related primarily to management services, income taxes and labor. These receivables were $1.2 million at December 31, 2006 and $0.8 million at December 31, 2005. Services provided by subsidiaries and charged to PacifiCorp primarily related to coal purchases. These payables were $8.9 million at December 31, 2006 and $7.3 million at December 31, 2005. Expense for these coal purchases were $94.2 million for the year ended December 31, 2006 and $70.0 million for the year ended December 31, 2005.

PacifiCorp is party to an umbrella loan agreement with one of its unconsolidated subsidiaries. Regulatory authorizations permit PacifiCorp to borrow from its subsidiaries (including those that are consolidated) without limitation and to loan each of these subsidiaries up to $30.0 million at any one time, provided that the borrowings bear interest at rates that do not exceed the interest rates that PacifiCorp would otherwise incur externally. As of December 31, 2006, affiliated notes receivable with unconsolidated subsidiaries were $22.9 million, including interest. As of December 31, 2005, affiliated notes payable with unconsolidated subsidiaries were $1.6 million, including interest.

Transactions while owned by ScottishPower

Under ScottishPower ownership, PacifiCorp engaged in various transactions with several of its former affiliated companies pursuant to ScottishPower's affiliated interest cross-charge policy. Services provided by PacifiCorp and charged to affiliates related primarily to administrative services provided to ScottishPower UK plc ("SPUK") and costs associated with retention agreements and severance benefits reimbursable by SPUK. In addition, PacifiCorp recharged to SPUK costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom and recharged support services to PHI and its subsidiaries. These receivables were $2.1 million at December 31, 2005. Amounts allocated to PacifiCorp by SPUK were primarily for administrative services received under the cross-charge policy and payroll costs and related benefits of SPUK employees working on international assignments with PacifiCorp in the United States. These liabilities were $2.3 million at December 31, 2005.

As of December 31, 2005, Taxes accrued included $6.3 million of taxes payable to PHI. PHI was the tax paying entity for PacifiCorp while owned by ScottishPower.

In May 2005, PacifiCorp began participating in a captive insurance program provided by Dornoch International Insurance Limited ("DIIL"), an indirect wholly owned consolidated subsidiary of ScottishPower. DIIL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp had no equity interest in DIIL and had no obligation to contribute equity or loan funds to DIIL. Premium amounts were established to cover loss claims, administrative expenses and appropriate reserves, but otherwise DIIL was not operated to generate profits. Certain costs associated with the captive insurance program were prepaid. Prepayments to DIIL were $1.8 million at December 31, 2005. Premium expenses were $5.4 million for the year ended December 31, 2005.

Revenues from these former affiliates related primarily to wheeling services and totaled $1.9 million for the year ended December 31, 2006 and $6.4 million for the year ended December 31, 2005. Expenses recharged by PacifiCorp to these former affiliates under the affiliated interest cross-charge policy totaled $2.0 million for the year ended December 31, 2006 and $15.5 million for the year ended December 31, 2005. Service provided by these former affiliates and charged to PacifiCorp under the affiliated interest cross-charge policy totaled $9.5 million for the year ended December 31, 2006 and $35.6 million for the year ended December 31, 2005.

Note 16 - Jointly Owned Utility Plants

Under joint plant ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission plants. PacifiCorp accounts for its proportional share of each plant.

Each participant has provided financing for its share of each unit. Operating costs of each plant are assigned to joint owners based on ownership percentage or energy taken, depending on the nature of the cost. Operating expenses on the accompanying Statement of Income include PacifiCorp's share of the expenses of these units.

As of December 31, 2006, PacifiCorp's share in jointly owned plants was as follows:

(Millions of dollars)	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4 (a)	66.7 %	$ 941.8	$ 459.9	$ 10.0
Wyodak	80.0	337.2	167.5	0.9
Hunter No. 1	93.8	305.3	141.9	0.9
Colstrip Nos. 3 and 4 (a)	10.0	241.2	114.3	1.1
Hunter No. 2	60.3	193.8	84.6	0.2
Hermiston (b)	50.0	168.3	36.3	0.8
Craig Nos. 1 and 2	19.3	166.2	73.0	0.2
Hayden No. 1	24.5	42.6	18.6	0.2
Foote Creek	78.8	36.3	11.5	0.1
Hayden No. 2	12.6	26.6	12.8	0.2
Other transmission and distribution plants	Various	79.2	18.1	0.4
Total		$ 2,538.5	$ 1,138.5	$ 15.0

(a) Includes transmission lines and substations.
(b) Additionally, PacifiCorp has contracted to purchase the remaining 50.0% of the output of the Hermiston Plant.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

Note 17 – Supplemental Cash Flow Information

A summary of supplemental cash flow information is presented in the following table:

(Millions of dollars)	Years Ended December 31, 2006	2005
Cash paid during the year for:		
Income taxes	$ 178.4	$ 86.1
Interest, net of amounts capitalized	244.8	236.2

Note 18 – Subsequent Events

On March 14, 2007, PacifiCorp sold an aggregate principal amount of $600.0 million of its 5.75% First Mortgage Bonds due April 1, 2037. PacifiCorp intends to use the net proceeds to repay short-term debt and for general corporate purposes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	8,516	(7,998,159)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	914,447	(992,768)		
4	Total (lines 2 and 3)	914,447	(992,768)		
5	Balance of Account 219 at End of Preceding Quarter/Year	922,963	(8,990,927)		
6	Balance of Account 219 at Beginning of Current Year	922,963	(8,990,927)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(1,416,499)			
8	Current Quarter/Year to Date Changes in Fair Value	503,402	8,990,927		(5,939,253)
9	Total (lines 7 and 8)	(913,097)	8,990,927		(5,939,253)
10	Balance of Account 219 at End of Current Quarter/Year	9,866			(5,939,253)

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			(7,989,643)		
2					
3			(78,321)		
4			(78,321)	301,176,223	301,097,902
5			(8,067,964)		
6			(8,067,964)		
7			(1,416,499)		
8		2,047,252	5,602,328		
9		2,047,252	4,185,829	307,934,288	312,120,117
10		2,047,252	(3,882,135)		

Schedule Page: 122(a)(b)   Line No.: 5   Column: b

Unrealized gain on available-for-sale securities of $1,487,476 less tax of $564,513 netting to $922,963.

Schedule Page: 122(a)(b)   Line No.: 5   Column: c

Minimum pension liability adjustment of ($14,489,872) less tax of $5,498,945 netting to ($8,990,927).

Schedule Page: 122(a)(b)   Line No.: 10   Column: b

Unrealized gain on available-for-sale securities of $15,900 less tax of $6,034 netting to $9,866.

Schedule Page: 122(a)(b)   Line No.: 10   Column: e

SFAS No. 158 - Defined Benefit Pension and Other Postretirement Plans adjustment of ($9,571,706) less tax of $3,632,453 netting to ($5,939,253).

Schedule Page: 122(a)(b)   Line No.: 10   Column: g

Unrealized gain on cash flow hedges of $3,299,410 less tax of $1,250,158 netting to $2,047,252.

For a further discussion on cash flow hedging, refer to Page 122, *Notes to the Financial Statements - Note 8 - Risk Management* of this Form No. 1.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	15,284,762,208	15,284,762,208
4	Property Under Capital Leases	49,253,139	49,253,139
5	Plant Purchased or Sold		
6	Completed Construction not Classified	32,340,315	32,340,315
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,366,355,662	15,366,355,662
9	Leased to Others		
10	Held for Future Use	3,361,997	3,361,997
11	Construction Work in Progress	734,457,063	734,457,063
12	Acquisition Adjustments	157,193,780	157,193,780
13	Total Utility Plant (8 thru 12)	16,261,368,502	16,261,368,502
14	Accum Prov for Depr, Amort, & Depl	6,408,699,464	6,408,699,464
15	Net Utility Plant (13 less 14)	9,852,669,038	9,852,669,038
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,945,570,482	5,945,570,482
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	383,240,168	383,240,168
22	Total In Service (18 thru 21)	6,328,810,650	6,328,810,650
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	79,888,814	79,888,814
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,408,699,464	6,408,699,464

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report End of 2006/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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					30
					31
					32
					33

Schedule Page: 200 Line No.: 18 Column: c

Depreciation is comprised of:

Depreciation	$5,902,280,246
Depletion	43,290,236
Total	$5,945,570,482

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	16,787,669	
3	(302) Franchises and Consents	117,555,186	712,577
4	(303) Miscellaneous Intangible Plant	537,849,411	32,878,783
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	672,192,266	33,591,360
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	81,496,795	9,869,528
9	(311) Structures and Improvements	770,111,431	10,363,231
10	(312) Boiler Plant Equipment	2,553,758,822	252,557,209
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	712,601,048	38,825,333
13	(315) Accessory Electric Equipment	329,362,786	5,683,232
14	(316) Misc. Power Plant Equipment	25,059,970	3,317,935
15	(317) Asset Retirement Costs for Steam Production	29,462,296	1,420,377
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	4,501,853,148	322,036,845
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	19,681,130	
28	(331) Structures and Improvements	80,011,168	1,775,347
29	(332) Reservoirs, Dams, and Waterways	280,231,813	8,546,757
30	(333) Water Wheels, Turbines, and Generators	86,077,183	2,719,600
31	(334) Accessory Electric Equipment	40,431,916	768,921
32	(335) Misc. Power PLant Equipment	3,189,506	-3,907
33	(336) Roads, Railroads, and Bridges	13,230,084	328,328
34	(337) Asset Retirement Costs for Hydraulic Production	5,531,361	936,050
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	528,384,161	15,071,096
36	D. Other Production Plant		
37	(340) Land and Land Rights	21,502,064	40,126
38	(341) Structures and Improvements	44,660,586	424,117
39	(342) Fuel Holders, Products, and Accessories	5,738,839	23,695,238
40	(343) Prime Movers	262,722,609	293,496,468
41	(344) Generators	83,479,920	42,383,034
42	(345) Accessory Electric Equipment	34,080,559	63,139
43	(346) Misc. Power Plant Equipment	3,640,805	
44	(347) Asset Retirement Costs for Other Production	755,214	293,561
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	456,580,596	360,395,683
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,486,817,905	697,503,624

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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 of

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
16,787,669					2
			118,267,763		3
11,732,417		384,249	559,380,026		4
28,520,086		384,249	677,647,789		5
					6
					7
1,760		-155,907	91,208,656		8
1,362,407		85,412	779,197,667		9
24,757,743		328,279	2,781,886,567		10
					11
12,205,291		-832,833	738,388,257		12
391,296		-2,087,477	332,567,245		13
70,938		23,182	28,330,149		14
			30,882,673		15
38,789,435		-2,639,344	4,782,461,214		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
548		-83,864	19,596,718		27
106,914		757,293	82,436,894		28
2,548,987		-150,023	286,079,560		29
855,218		82,907	88,024,472		30
406,984		803,241	41,597,094		31
9,134		-597,791	2,578,674		32
32,103		131,545	13,657,854		33
			6,467,411		34
3,959,888		943,308	540,438,677		35
					36
			21,542,190		37
3,011		4,500,918	49,582,610		38
		-25,138	29,408,939		39
5,475,240		-4,813,935	545,929,902		40
535,937		10,390	125,337,407		41
43,333			34,100,365		42
		80,000	3,720,805		43
			1,048,775		44
6,057,521		-247,765	810,670,993		45
48,806,844		-1,943,801	6,133,570,884		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	88,432,329	4,660,595
49	(352) Structures and Improvements	51,256,626	1,293,978
50	(353) Station Equipment	900,197,240	71,842,324
51	(354) Towers and Fixtures	372,507,097	4,596,975
52	(355) Poles and Fixtures	504,706,180	14,259,303
53	(356) Overhead Conductors and Devices	643,527,588	19,856,676
54	(357) Underground Conduit	2,369,500	907,688
55	(358) Underground Conductors and Devices	3,944,256	3,765,681
56	(359) Roads and Trails	11,376,682	117,840
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,578,317,498	121,301,060
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	36,656,799	8,029,208
61	(361) Structures and Improvements	40,844,880	261,223
62	(362) Station Equipment	630,494,507	26,970,489
63	(363) Storage Battery Equipment	1,285,571	54,286
64	(364) Poles, Towers, and Fixtures	774,914,028	41,369,193
65	(365) Overhead Conductors and Devices	577,399,999	15,750,461
66	(366) Underground Conduit	247,157,475	11,499,179
67	(367) Underground Conductors and Devices	581,320,885	31,631,610
68	(368) Line Transformers	882,647,097	48,365,397
69	(369) Services	421,954,840	42,793,938
70	(370) Meters	187,239,341	9,257,950
71	(371) Installations on Customer Premises	8,927,034	41,857
72	(372) Leased Property on Customer Premises	49,658	
73	(373) Street Lighting and Signal Systems	55,449,346	2,269,247
74	(374) Asset Retirement Costs for Distribution Plant		225,168
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,446,341,460	238,519,206
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	15,003,144	187,929
87	(390) Structures and Improvements	220,743,339	7,334,433
88	(391) Office Furniture and Equipment	118,744,458	9,422,532
89	(392) Transportation Equipment	86,849,740	15,451,912
90	(393) Stores Equipment	13,608,770	1,053,957
91	(394) Tools, Shop and Garage Equipment	60,329,825	3,462,210
92	(395) Laboratory Equipment	37,200,813	4,245,034
93	(396) Power Operated Equipment	114,707,566	14,161,346
94	(397) Communication Equipment	236,321,233	13,722,022
95	(398) Miscellaneous Equipment	5,773,191	313,351
96	SUBTOTAL (Enter Total of lines 86 thru 95)	909,282,079	69,354,726
97	(399) Other Tangible Property	242,845,520	12,062,499
98	(399.1) Asset Retirement Costs for General Plant		42,454
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,152,127,599	81,459,679
100	TOTAL (Accounts 101 and 106)	14,335,796,728	1,172,374,929
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		126,174
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	14,335,796,728	1,172,248,755

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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
38,929		-614,953	92,439,042		48
127,352		2,836,982	55,260,234		49
5,327,630		-3,377,373	963,334,561		50
522,837		4,797,068	381,378,303		51
1,951,400		-6,011,100	511,002,983		52
1,144,474		1,137,331	663,377,121		53
			3,277,188		54
435,279			7,274,658		55
			11,494,522		56
					57
9,547,901		-1,232,045	2,688,838,612		58
					59
4,063		-41,600	44,640,344		60
180,418		6,156,912	47,082,597		61
5,794,630		-4,386,754	647,283,612		62
		117,947	1,457,804		63
6,567,105		239,888	809,956,004		64
2,836,232		268,485	590,582,713		65
1,014,257		-380	257,642,017		66
1,299,006		1,085	611,654,574		67
8,060,625		16,079	922,967,948		68
978,065			463,770,713		69
7,081,005			189,416,286		70
99,636			8,869,255		71
			49,658		72
687,914			57,030,679		73
			225,168		74
34,602,956		2,371,662	4,652,629,372		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-160,770	15,030,303		86
8,712,606		5,368,180	224,733,346		87
19,442,275		-4,402,178	104,322,537		88
5,643,286		16,577	96,674,943		89
1,525,244		2,627	13,140,110		90
3,138,384		110,064	60,763,715		91
4,108,487		230,126	37,567,486		92
9,472,008		2,781,602	122,178,506		93
15,899,310		-2,029,879	232,114,066		94
727,515		28,305	5,387,332		95
68,669,115		1,944,654	911,912,344		96
-138,463		-2,585,414	252,461,068		97
			42,454		98
68,530,652		-640,760	1,164,415,866		99
190,008,439		-1,060,695	15,317,102,523		100
					101
126,174					102
					103
189,882,265		-1,060,695	15,317,102,523		104

Schedule Page: 204 Line No.: 97 Column: b

Account (a)	Description (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements (e)	Transfers (f)	Balance at End of Year (g)
39921	LAND OWNED IN FEE	$2,634,916	$ -	$ -	$ -	$2,634,916
39922	LAND RIGHTS	52,452,647	19,600	-	-	52,472,247
39930	STRUCTURES	37,275,271	73,328	(20,372)	-	37,328,227
39941	SURFACE - PLANT EQUIPMENT	11,639,175	155,183	-	-	11,794,358
39944	SURFACE - ELECTRIC POWER FACILITIES	566,476	3,181,747	-	(566,476)	3,181,747
39945	UNDERGROUND - COAL MINE EQUIPMENT	54,786,437	2,469,139	(1,154,558)	(742,791)	55,358,227
39946	LONGWALL SHIELDS	17,678,600	20,962	-	-	17,699,562
39947	LONGWALL EQUIPMENT	10,762,131	87,931	(63,460)	-	10,786,602
39948	MAINLINE EXTENSION	13,584,135	1,385,029	(427,150)	711,643	15,253,657
39949	SECTION EXTENSION	2,828,109	462,358	-	-	3,290,467
39951	VEHICLES	1,037,811	90,656	(59,999)	29,683	1,098,151
39952	HEAVY CONSTRUCTION EQUIPMENT	3,510,169	62	2,001,043	(2,024,690)	3,486,584
39960	MISCELLANEOUS GENERAL EQUIPMENT	2,082,025	162,200	(137,041)	7,217	2,114,401
39961	COMPUTERS - MAINFRAME	578,123	22,341	-	-	600,464
39970	MINE DEVELOPMENT AND ROAD EXTENSTION	31,429,495	3,270,775	-	-	34,700,270
399915	Coal Mine ARO	-	661,188	-	-	661,188
	TOTAL PLANT USED IN MINING ACTIVITIES	$242,845,520	$12,062,499	$138,463	$ (2,585,414)	$252,461,068

Schedule Page: 204 Line No.: 97 Column: c

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: d

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: f

See footnote line 97, column b.

Schedule Page: 204 Line No.: 97 Column: g

See footnote line 97, column b.

Schedule Page: 204 Line No.: 102 Column: c

In July 2006, PacifiCorp completed the sale of a three-mile 230-kV transmission line and related facilities, associated easements and right-of-way located near Centralia, Washington to TransAlta Centralia Generation LLC, with proceeds totaling $117,024. The FERC authorized the sale of the facilities in Docket No. EC06-59-000. Approval to clear account 102 was approved in Docket AC07-35-000 on December 14, 2006.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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				
3	Oquirrh Substation	2005	2009	2,245,898
4	North Horn Mountain Coal Properties	1977	2010-2018	953,014
5				
6				
7				
8				
9	Miscellaneous, each under $250,000			163,085
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26	Miscellaneous, each under $250,000:			
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			3,361,997

Schedule Page: 214 Line No.: 3 Column: c

Property for future 345/138 kV substation to be built in 2009.

Schedule Page: 214 Line No.: 4 Column: c

The North Horn Mountain Coal Properties are needed to access future coal portals and federal coal reserves when existing East Mountain coal mines are mined out.

Schedule Page: 214 Line No.: 9 Column: c

Various dates and plans.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Intangible:	
2	Klamath Relicensing	42,084,337
3	Yale Relicensing (Lewis River)	12,433,652
4	Merwin Relicensing (Lewis River)	9,505,341
5	Swift Relicensing (Lewis River)	9,037,292
6	Prospect 1, 2 & 4 Relicensing (Rogue River)	5,909,264
7	Hayden Plant - Routt County Road Improvements - Coal Haul	1,098,492
8		
9	Production:	
10	Lake Side Generating Plant (Natural Gas-Fired)	264,939,669
11	Marengo Wind Plant	49,602,609
12	Goodnoe Hills East & West Wind Plant	44,722,843
13	Cholla Unit 4: CAI Environmental Projects	33,296,234
14	North Umpqua Relicensing Implementation	6,420,825
15	Huntington Water Efficiency Management	5,819,573
16	Blundell Bottoming Cycle	5,268,520
17	Lewis River Relicensing Implementation	4,234,274
18	Hunter Unit 3 Main Controls System Upgrade	4,110,777
19	Dave Johnston Unit 4 - Boiler Controls/Turbine Controls	1,675,922
20	Hunter Unit 3 NOx	1,539,389
21	Hunter Unit 3 Reheater Replacements	1,532,569
22	Lake Side Capitalized Spare Parts	1,464,372
23	Hunter Unit 3 Turbine L-0 Bucket Replacements	1,442,521
24	Hunter Unit 3 Turbine HP Nozzle Box	1,210,647
25	Copco 2 Electrical Overhaul	1,205,816
26	Cholla Unit 4 D Mill Overhaul	1,097,243
27	Jim Bridger Refurbish Generator Field for Unit 3	1,040,323
28		
29	Transmission:	
30	Summit-Vineyard (Lake Side) Transmission Project	27,893,416
31	Camp Williams-Mona 345 kV No 4 Line	20,745,329
32	Cache Valley Add. Bridgerland Switching Station Phase 1	12,800,283
33	Summit-Vineyard (Lake Side) Interconnect	6,423,094
34	Line 1 Convert to 115kV, Line 14 Cap Relief	5,711,109
35	Marengo Wind-Install Switch Station	3,297,170
36	Craven Creek 230kV Svc Enterprise Pd Pioneer	2,438,568
37	Marquam 115kV Line Relocation for N Macadam Dev	2,322,181
38	Quail Creek Sub - convert to 69kV, Install Transformer	1,771,466
39	Hunter 4 Emery-Mona-Oquirrh Mona Cap	1,279,908
40	Midpoint-Summer Lake 500 kV Replace Relays	1,182,162
41	Oakley-Kamas New 46kV Line	1,169,191
42		
43	TOTAL	734,457,063

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Distribution:	
2	Latham Install 230-34 5kV 25MVA Sub	4,933,469
3	Bond Street - Construct New 69-12.5 Sub	3,853,876
4	Yew Avenue - Construct New Sub (Tetherow)	2,641,394
5	Business Depot Ogden - Build 138-12.5kV Sub & Line 30MVA	2,303,474
6	Porter Rockwell New 138-12.5kV Sub	1,263,389
7	UDOT 10400 S to 11700 S Redwood Rd	1,037,039
8		
9	General:	
10	IP Telephony Project	2,856,206
11	Mainframe & Open Systems Storage	1,363,566
12		
13	Miscellaneous Projects each under $1,000,000	116,478,269
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	734,457,063

Schedule Page: 216.1 Line No.: 13 Column: a

A $1,000,000 reporting threshold was approved for PacifiCorp effective with the 1993 reporting year by the Chief Accountant, Federal Regulatory Commission in a letter to the company dated August 5, 1993, Docket No. AC93-181-000.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	5,690,545,718	5,690,545,718		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	390,945,206	390,945,206		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	29,856,680	29,856,680		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	420,801,886	420,801,886		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	158,186,488	158,186,488		
13	Cost of Removal	41,566,452	41,566,452		
14	Salvage (Credit)	7,371,817	7,371,817		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	192,381,123	192,381,123		
16	Other Debit or Cr. Items (Describe, details in footnote):	26,604,001	26,604,001		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	5,945,570,482	5,945,570,482		

Section B. Balances at End of Year According to Functional Classification

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)
20	Steam Production	2,392,612,597	2,392,612,597		
21	Nuclear Production				
22	Hydraulic Production-Conventional	236,407,265	236,407,265		
23	Hydraulic Production-Pumped Storage				
24	Other Production	77,747,587	77,747,587		
25	Transmission	1,022,242,292	1,022,242,292		
26	Distribution	1,759,774,576	1,759,774,576		
27	Regional Transmission and Market Operation				
28	General	456,786,165	456,786,165		
29	TOTAL (Enter Total of lines 20 thru 28)	5,945,570,482	5,945,570,482		

Schedule Page: 219 Line No.: 4 Column: b

PacifiCorp records the depreciation expense of asset retirement obligations as either a regulatory asset or (liability).

Schedule Page: 219 Line No.: 8 Column: b

Depreciation of mining assets included in account 151 Fuel Stock	12,903,462
Account 143.3 Joint Owner Receivable - Depreciation expense billed to Joint Owners	231,586
Account 182.3 Other Regulatory Assets	3,048,583
Vehicle Depreciation allocated to O&M based on usage activity	12,268,419
Account 503.1 Blundell Depletion	1,116,724
Account 503 IGC Depreciation and Amortization	287,906
Total Other Accounts	$ 29,856,680

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

Other items including:	$ 26,604,001

- -Recovery from third parties for asset relocations and damaged property
- -Insurance recoveries
- -Adjustments of reserve related to electric plant sold
- -Reclassifications from electric plant
- -IGC Acquisition

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	PACIFIC POWER & LIGHT COMPANY			
2	Common Stock			100
3	SUBTOTAL			100
4				
5	CENTRALIA MINING COMPANY	7/20/1990		
6	Common Stock			1,000
7	SUBTOTAL			1,000
8				
9	ENERGY WEST MINING COMPANY	7/18/1990		
10	Common Stock			1,000
11	SUBTOTAL			1,000
12				
13	PACIFIC MINERALS, INC	12/31/1991		
14	Common Stock			1
15	Capital Contributions			
16	Undistributed Earnings			75,332,655
17	SUBTOTAL			75,332,656
18				
19	GLENROCK COAL COMPANY	12/31/1991		
20	Common Stock			1
21	SUBTOTAL			1
22				
23	INTERWEST MINING COMPANY	12/11/1992		
24	Common Stock			1,000
25	SUBTOTAL			1,000
26				
27	PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY	8/19/1994		
28	Common Stock			900,000
29	Capital Contributions			944,419
30	Undistributed Subsidiary Earnings			7,677,807
31	SUBTOTAL			9,522,226
32				
33	PACIFIC FUTURE GENERATIONS, INC	9/19/1999		
34	Undistributed Subsidiary Earnings			-4,581
35	SUBTOTAL			-4,581
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 6,508,526		TOTAL	84,853,402

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
			-100	2
			-100	3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
		1		14
		14,160,000		15
11,269,410		86,602,065		16
11,269,410		100,762,066		17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
		900,000		28
		5,608,526		29
-1,826,786		5,851,021		30
-1,826,786		12,359,547		31
				32
				33
-5,046		-9,627		34
-5,046		-9,627		35
				36
				37
				38
				39
				40
				41
9,437,578		113,111,986	-100	42

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

Centralia Mining Company is a wholly owned subsidiary of PacifiCorp and supports the electric utility operations. PacifiCorp consolidates Centralia Mining Company for financial statement presentation in the accompanying financial statements included in this Form No. 1.

Schedule Page: 224 Line No.: 10 Column: g

Energy West Mining Company is a wholly owned subsidiary of PacifiCorp and supports the electric utility operations. PacifiCorp consolidates Energy West Mining Company for financial statement presentation in the accompanying financial statements included in this Form No. 1.

Schedule Page: 224 Line No.: 15 Column: g

Reflects $14,160,000 capital contribution from parent company in 2006.

Schedule Page: 224 Line No.: 16 Column: e

Equity earnings from Pacific Minerals, Inc. (PMI) consist of inter-company profit on coal ot PacifiCorp from Bridger Coal Company, that PMI jointly owns with Idaho Power Company, and are not recorded in account 418.1, Equity in Earnings of Subsidiary Companies. In order to eliminate the inter-company profit on the coal sales, PacifiCorp records PMI's earnings as an offset to fuel expense.

Schedule Page: 224 Line No.: 20 Column: g

Glenrock Coal Company is a wholly owned subsidiary of PacifiCorp and supports the electric utility operations. PacifiCorp consolidates Glenrock Coal Company for financial statement presentation in the accompanying financial statements included in this Form No. 1.

Schedule Page: 224 Line No.: 24 Column: g

Interwest Mining Company is a wholly owned subsidiary of PacifiCorp and supports the electric utility operations. PacifiCorp consolidates Interwest Mining Company for financial statement presentation in the accompanying financial statements included in this Form No. 1.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	56,631,067	82,230,862	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)	48,271,495	48,572,876	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	57,180,564	64,636,918	Electric
8	Transmission Plant (Estimated)	2,915,364	4,250,120	Electric
9	Distribution Plant (Estimated)	5,815,760	8,330,981	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	3,776,589	3,940,971	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	117,959,772	129,731,866	
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)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	174,590,839	211,962,728	

Schedule Page: 227 Line No.: 11 Column: b

	2006
Mining M&S	$3,624,940
General Plant M&S	151,649
	$3,776,589

Schedule Page: 227 Line No.: 11 Column: c

	2005
Mining M&S	$3,408,500
General Plant M&S	532,471
	$3,940,971

Allowances (Accounts 158.1 and 158.2)

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

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2007 No. (d)	2007 Amt. (e)
1	Balance-Beginning of Year	143,315.00		100,352.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	103,584.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	J.P. Morgan	10,000.00			
23					
24					
25					
26					
27					
28	Total	10,000.00			
29	Balance-End of Year	29,731.00		100,352.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	2,259.00		2,259.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	2,259.00			
40	Balance-End of Year			2,259.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

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Allowances (Accounts 158.1 and 158.2) (Continued)

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

2008		2009		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
113,095.00		121,095.00		4,022,791.00		4,500,648.00		1
								2
								3
				156,643.00		156,643.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						103,584.00		18
								19
								20
								21
						10,000.00		22
								23
								24
								25
								26
								27
						10,000.00		28
113,095.00		121,095.00		4,179,434.00		4,543,707.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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	Unrecovered Plant: Trojan Nuclear	8,513,886		407	1,674,864	6,839,022
22	Plant located near Portland, OR					
23	Date of Retirement: 12/31/1992					
24	Date of Commission Authorization:					
25	04/20/1993					
26	Amortization Period: 01/1993					
27	through 01/2011					
28						
29	Unrecovered Plant: Trail Mountain	1,326,026		151	1,326,026	
30	Date of Retirement: 03/15/2001					
31	Date of Commission Authorization:					
32	04/04/2002 - UT					
33	05/20/2002 - OR					
34	04/26/2001 - WY					
35	04/26/2001 - ID					
36	Amortization Period: 04/2001					
37	through 03/2006					
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	9,839,912			3,000,890	6,839,022

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Q0106	547	561.6	547	456.2
3	Q0069	3,506	561.6	3,506	456.2
4	Q0106/Q0107	22,168	561.6	22,168	456.2
5	Q0247-Q0255	985	561.6	985	456.2
6	Q0226/0227	2,190	561.6	2,190	456.2
7	Q0220	450	561.6	450	456.2
8	Q0296	1,155	561.6	1,155	456.2
9	Q0317	1,899	561.6	1,899	456.2
10	Aref 355217	1,809	561.6	1,809	456.2
11	Aref 314945	9,381	561.6	3,285	456.2
12	Aref 367339	1,369	561.6	1,369	456.2
13	Various Customer Studies	839,486	107, 561.6		
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0059, LGIQ0059	160,469	561.7	150,765	456.2
23	GIQ0060, GIQ0063/64	43,435	561.7	22,868	456.2
24	GIQ0060/61	41,597	561.7	26,645	456.2
25	QFI0051	26,170	561.7	26,170	456.2
26	GIQ0056, QFIQ0056	24,587	561.7	24,587	456.2
27	See footnote	22,708	561.7	22,081	456.2
28	GIQ0080, GIQ0089	18,811	561.7	18,097	456.2
29	GIQ0073	16,724	561.7	13,634	456.2
30	GIQ0091	16,037	561.7	12,663	456.2
31	GIQ0054, QFIQ0054	15,911	561.7	15,911	456.2
32	GIQ0072	12,929	561.7	12,929	456.2
33	GIQ0074	12,367	561.7	11,565	456.2
34	GIQ0090, GIQ0096	12,083	561.7	11,977	456.2
35	Misc Studies (<10k)	41,774	561.7	36,459	456.2
36	Misc Studies-Not Reimbursed	69,557	561.7		
37	Aref 316762	13,470	107		
38					
39					
40					

Name of Respondent PacifiCorp	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 2006/Q4

FOOTNOTE DATA

Schedule Page: 231 Line No.: 27 Column: a

Generation Studies: GIQ0071, GIQ0087, GIQ0088,GIQ0092, SGIQ0071

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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	Deferred Intervenor Funding Grants	529,353	332,179			861,532
2	California DSM Regulatory Asset	(271,984)	271,912	908	221,452	-221,524
3	Idaho DSM Regulatory Asset	6,188,034	1,530,049	908	2,462,146	5,255,937
4	Utah DSM Regulatory Asset	6,093,204	24,523,949	Various	29,924,162	692,991
5	Washington DSM Regulatory Asset	(1,570,984)	6,888,516	431, 908	7,109,276	-1,791,744
6	Wyoming DSM Regulatory Asset (10)	372,976	39,575	908	83,498	329,053
7	Transition Plan - OR (10)	17,838,770		930.2	3,892,299	13,946,471
8	FAS 109 Deferred Income Taxes Electric	485,147,154		282	21,049,892	464,097,262
9	SB 1149 Implementation Costs OR Retail Access (5)	15,306,830	3,077,014	407.3	6,825,579	11,558,265
10	Y2K Expense 98-00 OR (7)	59,381		930.2	59,381	
11	98 Early Retirement OR (4)	7,353,893		930.2	3,676,947	3,676,946
12	Glenrock Mine Excluding Reclamation UT (9)	5,033,621		930.2	1,302,399	3,731,222
13	Deferred Excess Net Power Costs OR UE116	126,803	10,913			137,716
14	Environmental Costs (10)	7,120,116	452,488	925	1,527,588	6,045,016
15	Environmental Costs - WA (10)	(367,157)	13,942			-353,215
16	Deferred Cost of TOU Guarantee	1,804		930.2	1,804	
17	IDAI Costs No. CA Direct Access (5)	971,556		407.3	333,105	638,451
18	Cholla Plant Transaction Costs (26)	13,001,422		557	1,122,425	11,878,997
19	Cholla Plant Transaction Costs OR (26)	(623,335)	53,813			-569,522
20	Cholla Plant Transaction Costs WA (26)	(1,123,655)	97,006			-1,026,649
21	Cholla Plant Transaction Costs ID (26)	(381,941)	32,973			-348,968
22	Washington Colstrip #3 (22)	787,199		456	52,188	735,011
23	Trail Mountain Mine Closure Costs	663,410		151	663,410	
24	Trail Mountain Mine - Deseret Settlement	(132,782)	132,782			
25	FAS133 Derivative Net Regulatory Asset		229,837,168			229,837,168
26	FAS 87/88 Pension UT (7)	6,318,028		930.2	3,159,014	3,159,014
27	Noell Kempf CAP UT	1,757		930.2	1,757	
28	P&M Strike Amort UT (3)	199,634		930.2	199,634	
29	Energy Trust of Oregon SB1149	19,686	1,111	143	19,686	1,111
30	Retail Access Project INC.	1,995,562	1,120,973	182.3	1,960,000	1,156,535
31	Asset Retirement Obligations Regulatory Difference	28,264,094	30,772,979	230	4,176,143	54,860,930
32	DSM Regulatory Assets - Accruals	3,524,830		232	761,289	2,763,541
33	Regulatory Assets - Reclass	1,299,592	791,038			2,090,630
34	Sch 781 Direct Access Shopping Incentive	840,807	596,290	407.3	537,839	899,258
35	FAS 158 Pension/Other Post Ret./SERP	280,655,740	285,273,451	Various		565,929,191
36	RTO Grid West N/R Reg Asset		1,131,721			1,131,721
37	Contra Reg Asset - RTO Grid West			904	1,131,721	-1,131,721
38	RTO Grid West N/R - OR		810,234			810,234
39	RTO Grid West N/R - WY		414,098			414,098
40	RTO Grid West N/R - ID		135,811			135,811
41	Deferred Excess Net Power Costs - WY		2,554,006			2,554,006
42	OR SB 408 Recovery		4,760,000	254	2,454,610	2,305,390
43	Reg Asset - Enrionmental Costs		8,080,491			8,080,491
44	TOTAL	885,243,418	605,126,212		94,709,244	1,395,660,386

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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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Calif. Alternative Rate for Energy (CARE)		1,389,730			1,389,730
2						
3						
4						
5						
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42						
43						
44	TOTAL	885,243,418	605,126,212		94,709,244	1,395,660,386

Schedule Page: 232 Line No.: 4 Column: d

Account 431
Account 908

Schedule Page: 232 Line No.: 33 Column: f

The following is a reconciliation of the regulatory asset reclassification account:

Reclassified from Regulatory Assets to Regulatory Liabilities:		
California DSM Regulatory Asset	$	221,524
Washington DSM Regulatory Asset		1,791,744
Reclassified from Regulatory Liabilities to Regulatory Assets:		
Washington Low Income Program		68,874
Utah Home Energy Lifeline (11)		8,486
	$	2,090,628

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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	Joseph Settlement (20)	1,660,018		557	137,381	1,522,637
2						
3	Lacomb Irrigation (24)	735,330		557	45,720	689,610
4						
5	Facilities and Properties	84,847	219,121			303,968
6						
7	Bogus Creek (42)	1,406,960		557	41,280	1,365,680
8						
9	Intangible Pension Asset:					
10	SERP Plan	935,007		219, 228	935,007	
11	Pension Intangible Asset	24,102,000			24,102,000	
12						
13	Mead Phoenix Availability					
14	& Trans Charge (50)	15,645,560		565	377,760	15,267,800
15						
16	Lakeview Buyout (13)	133,445		557	43,279	90,166
17						
18	TGS Buyout (20)	217,918		557	15,473	202,445
19						
20	Hermiston Swap (20)	5,710,478		557	539,573	5,170,905
21						
22	Deferred Longwall Costs	1,577,345	2,421,423	151	2,230,216	1,768,552
23						
24	Other Deferred Debits with					
25	Amounts less than $50,000	287,928	530,741	151	505,309	313,360
26						
27	Point to Point Transmission	1,099,267	981,090		1,521,356	559,001
28						
29	Deferred Costs Wyodak					
30	Settlement (22)	5,698,090		151	335,181	5,362,909
31						
32	Jim Boyd Hydro Buyout (11)	669,785		557	82,860	586,925
33						
34	Deferred Shelf Registration	279,320	4,218			283,538
35						
36	Credit Agmt Costs (5)	2,411,433	312,239	431	510,139	2,213,533
37						
38	PCRB LOC/SBBPA Cost (5)	1,372,867	222,484	427	344,476	1,250,875
39						
40	Unamortized PCRB Mode Conv Cost	774,123		427	128,039	646,084
41						
42	Deferred Chrgs-Water Rights	725,776		506	725,776	
43						
44						
45	Emission Reduction Credits	406,980				406,980
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	65,950,331				57,976,248

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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	Mine Depreciation Clearing	15,854		151	15,854	
2						
3	Non-Current Fed/State Inc Tax		12,741,862			12,741,862
4						
5	LGIA LT Transmission Prepaid		6,898,901			6,898,901
6						
7	WA Environmental Cost-Utah Mtls		290,803			290,803
8						
9	Financing Costs Deferred		872,573	181, 186	861,386	11,187
10						
11	Property Damage Repairs		92,711	228	64,184	28,527
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	65,950,331				57,976,248

FOOTNOTE DATA

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

Account 182
Account 219
Account 228

Schedule Page: 233 Line No.: 27 Column: d

Account 142
Account 419
Account 557

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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	Regulatory Liabilities	315,652,418	319,921,216
3	Employee Benefits	181,198,165	294,345,786
4	FAS 133 Derivatives	45,748,981	102,310,588
5	PMI Deferred Assets		6,514,736
6			
7	Other	144,655,950	96,595,152
8	TOTAL Electric (Enter Total of lines 2 thru 7)	687,255,514	819,687,478
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	687,255,514	819,687,478

Notes

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FOOTNOTE DATA

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

Description	Balance at Beginning of Year	Balance at End of Year
DTA FAS 143 ARO Liability	$ 33,964,767	$ 27,665,893
DTA Reg Liabilities	14,443,493	-
DTA Distribution O&M Amort of Writeoff	22,616,889	749,975
DTA M&S Inventory Write-Off	2,812,892	-
DTA 205.200 M&S Inventory Write-off	-	4,611,872
DTA Bad Debts Allowance - Cash Basis	15,160,247	4,726,876
DTA 425.225 Duke Contract Novation	-	1,301,046
DTA Unearned Joint Use Pole Contract Rev.	616,105	1,335,983
DTA 425.380 Idaho Customer Balancing Account	49,715	3,001,027
DTA Centralia Sale	2,947,073	4,938,878
DTA U of WY Contract Amort - Prepaid	1,165,555	212,024
DTA Def Reg Asset - Transmission Service Deposit	660,145	619,340
DTA Def. Reg Asset - Foote Creek Contract	515,789	424,377
DTA Redding Contract - Prepaid	2,243,873	1,878,599
DTA 110.100 Book Depletion	-	8,111,099
DTA 505.125 Accrued Royalties	-	762,599
DTA Final Reclamation - Cash Basis	17,938,996	-
DTA Trail Mountain Accrued Liabilities	723,026	1,180,167
DTA Montana Sale Accrual	220,116	129,792
DTA 715.050 Microsoft Lic Liability	-	404,083
DTA Purchase Card Trans Provision	363,219	-
DTA Misc. Current and Accrued Liability	6,429,391	6,698,533
DTA Injuries & Damages Accrual - Cash Basis	1,975,748	1,688,805
DTA Wasatch Workers Comp Reserve	2,131,460	1,907,154
DTA 920.150 FAS 112 Book Reserve	459,220	1,702,405
DTA Bogus Creek Settlement	44,782	-
DTA 425.120 Bear River Settlmt Agrmt	134,346	5,143,503
DTA 425.320, N. Umpqua Settlemt Agreemt	-	8,682,408
DTA Legal Reserve	759,020	-
DTA 610.010 NOPA 103 99-00 RAR	3,415,599	-
DTA 610.035N NOPA 90 99-00 RAR	496,680	-
DTA 610.090 NOPA 102 99-00 RAR	116,253	-
DTA 610.075 NOPA 89 99-00 RAR	101,623	-
DTA 610.070N NOPA 88 99-00 RAR	1,861,497	-
DTA 610.020N NOPA's 72, 73 91 99-00 RAR	59,355	-
DTA 610.100N Amort NOPA's 99-00 RAR	631,392	-
DTA 610.020N NOPA's 110, 111, & 130 99-00 RAR	2,128,665	-
DTA 610.100N Amortization NOPA's 99-00 RAR	-	330,685
DTA Weather Derivatives	2,252,773	-
DTA Amort of Debt Disc & Exp	77,561	21,315
DTA Defer MagCorp Revenues	749,905	1,590
DTA Deferred Comp Accrual - Cash Basis	-	2,077,710
DTA Special Assessment - DOE	40,174	14,795
DTA Amortization Overburden	507,091	-
DTA Merger Cost Amort	1,137,477	-
DTA Amort of Projects - Klamath Engineering	7,072	2,806
DTA 425.110 Tennant Lease Allow-PSU Call Center	152,298	136,014
DTA 210.000, Prepaid Ins. Cont. Reserve	(195,931)	-

DTA 610.120 Trail Mountain	227,768	-
DTA 605.200 WY Jt Water Rd	569,289	370,022
DTA 505.115 Sales & Use Tax	50,718	-
DTA 505.160 Cal PUC Fee	-	9,108
DTA 425.295 BPA Rate Credits	-	162,716
DTA 425.300 Mead Phoenix Avail & Trans Charge	-	286,727
DTA Idaho ITC Carryforward	-	1,498,675
DTA - BETC Purchased Credits	1,892,824	1,977,769
DTA 920.160 Stock Incentive Plan	-	1,079,927
DTA 920.170 Exec Stock Option Plan	-	748,855
Total	$ 144,655,950	$ 96,595,152

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report End of 2006/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock (Account 201)	750,000,000		
2	PacifiCorp is a wholly			
3	owned indirect subsidiary of			
4	MidAmerican Energy Holdings Company			
5				
6	TOTAL COMMON STOCK	750,000,000		
7				
8				
9	Preferred Stock (Account 204):			
10	5% Cumulative Preferred	126,533	100.00	110.00
11	(American Stock Exchange)			
12				
13	Serial Preferred, Cumulative:	3,500,000		
14	4.52% Series		100.00	103.50
15	7.00% Series		100.00	
16	6.00% Series		100.00	
17	5.00% Series		100.00	100.00
18	5.40% Series		100.00	101.00
19	4.72% Series		100.00	103.50
20	4.56% Series		100.00	102.34
21				
22	TOTAL PREFERRED STOCK	3,626,533		
23				
24				
25				
26				
27				
28				
29				
30				
31	Authorized and unissued Capital Stock			
32				
33				
34				
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42				

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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)	
357,060,915	3,417,945,896					1
						2
						3
						4
						5
357,060,915	3,417,945,896					6
						7
						8
						9
126,243	12,624,300					10
						11
						12
						13
2,065	206,500					14
18,046	1,804,600					15
5,930	593,000					16
41,908	4,190,800					17
65,959	6,595,900					18
69,890	6,989,000					19
84,592	8,459,200					20
						21
414,633	41,463,300					22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
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						40
						41
						42

Schedule Page: 250   Line No.: 1   Column: d

This class of stock is not redeemable.

Schedule Page: 250   Line No.: 9   Column: a

Except as specifically noted, all preferred stock series trade as unlisted securities.

Schedule Page: 250   Line No.: 15   Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250   Line No.: 16   Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250   Line No.: 31   Column: a

Authorizations for the issuance of common stock by PacifiCorp to its immediate corporate parent, PPW Holdings LLC are as follows:

Utah Public Service Commission, Docket No. 06-035-61, Report and Order, dated July 10, 2006.

Oregon Public Utility Commission, Docket No. UF-4228, Order No. 06-417, dated July 17, 2006.

Washington Utilities and Transportation Commission, Docket No. UE-060974, Order No. 1, dated June 28, 2006.

Idaho Public Utilities Commission, Case No. PAC-E-06-7, Order No. 30099, dated July 7, 2006.

As of December 31, 2006 30,000,000 shares authorized; 30,000,000 available.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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 211 Miscellaneous Paid-in Capital	
2	Additional Paid-in Capital	
3	Share based payments	1,973,218
4	Tax effect of stock options	10,644,252
5	Benefit plan separation	-3,575,760
6	Capital contributions	214,950,000
7	Gain on sale of ScottishPower stock	136,208
8	Qualified production activity tax deduction	-1,275,241
9	Contribution of Intermountain Geothermal	432,552
10		
11		
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40	TOTAL	223,285,229

Schedule Page: 253 Line No.: 3 Column: b

This represents the fair value of stock options granted by ScottishPower for which certain performance measures were met in March 2005. These options became fully vested in May 2005.

Schedule Page: 253 Line No.: 4 Column: b

This represents the income tax deduction attributable to the exercise of stock options granted by ScottishPower. This deduction is required to be recorded through an adjustment to additional paid-in-capital.

Schedule Page: 253 Line No.: 5 Column: b

This represents the effect of transferring benefit plans to PPM Energy as a result of the sale of PacifiCorp by ScottishPower. This is required to be recorded through an adjustment to additional paid-in-capital.

Schedule Page: 253 Line No.: 6 Column: b

Capital contributions to PacifiCorp (with no shares of stock issued) from its immediate corporate parent PPW Holdings LLC.

Schedule Page: 253 Line No.: 7 Column: b

Represents a realized gain on sale of stock for PPM Energy participants in the deferred compensation plan, required to be recorded in additional paid-in-capital.

Schedule Page: 253 Line No.: 8 Column: b

Represents an equity adjustment related to the transfer of PPM Energy's IRC 199 qualified production activities.

Schedule Page: 253 Line No.: 9 Column: b

Contribution of Intermountain Geothermal Company ("IGC") to PacifiCorp from MEHC. For additional information regarding IGC, refer to page 108, *Important Changes During the Year*, ITEM 2, of this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	41,101,062
2		
3	Preferred Stock:	
4	5.00% Serial	98,049
5	4.52% Serial	9,676
6	4.72% Serial	30,349
7	4.56% Serial	49,071
8		
9		
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21		
22	TOTAL	41,288,207

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Bonds: (Account 221)		
2	First Mortgage Bonds:		
3	5.650% Series due November 1, 2006	200,000,000	6,185,966
4			670,000 D
5	4.300% Series due September 15, 2008	200,000,000	1,322,659
6			288,000 D
7	8.271% Series due October 1, 2010	48,972,000	
8	7.978% Series due October 1, 2011	4,422,000	
9	6.900% Series due November 15, 2011	500,000,000	3,567,009
10			1,735,000 D
11	8.493% Series due October 1, 2012	19,772,000	
12	8.797% Series due October 1, 2013	16,203,000	
13	5.45 % Series due September 15, 2013	200,000,000	1,422,659
14			232,000 D
15	4.950% Series due August 15, 2014	200,000,000	1,442,365
16			728,000 D
17	8.734% Series due October 1, 2014	28,218,000	
18	8.294% Series due October 1, 2015	46,946,000	
19	8.635% Series due October 1, 2016	18,750,000	
20	8.470% Series due October 1, 2017	19,609,000	
21	7.700% Series due November 15, 2031	300,000,000	2,874,150
22			864,000 D
23	5.900% Series due August 15, 2034	200,000,000	1,892,365
24			722,000 D
25	5.25% Series due June 15, 2035	300,000,000	2,912,021
26			1,080,000 D
27	6.10% Series due August 1, 2036	350,000,000	2,767,726
28			1,141,000 D
29	6.12% Series G Medium-Term Notes due Jan. 15, 2006	100,000,000	679,467
30	7.67% Series C Medium-Term Notes due Jan. 10, 2007	5,724,000	36,625
31	6.625% Series G Medium-Term Notes due June 1, 2007	100,000,000	1,267,428
32			630,000 D
33	TOTAL	4,521,486,000	58,967,468

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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
11/06/1998	11/01/2006	11/06/1998	11/01/2006		9,416,667	3
						4
09/15/2003	09/15/2008	09/15/2003	09/15/2008	200,000,000	8,600,000	5
						6
04/15/1992	10/01/2010	04/15/1992	10/01/2010	16,945,000	1,616,091	7
04/15/1992	10/01/2011	04/15/1992	10/01/2011	1,770,000	157,905	8
11/15/2001	11/15/2011	11/15/2001	11/15/2011	500,000,000	34,500,000	9
						10
04/15/1992	10/01/2012	04/15/1992	10/01/2012	9,230,000	856,838	11
04/15/1992	10/01/2013	04/15/1992	10/01/2013	8,467,000	800,923	12
09/15/2003	09/15/2013	11/15/2001	09/15/2013	200,000,000	10,900,000	13
						14
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	15
						16
04/15/1992	10/01/2014	04/15/1992	10/01/2014	15,952,000	1,481,155	17
04/15/1992	10/01/2015	04/15/1992	10/01/2015	27,903,000	2,440,986	18
04/15/1992	10/01/2016	04/15/1992	10/01/2016	11,959,000	1,080,325	19
04/15/1992	10/01/2017	04/15/1992	10/01/2017	13,052,000	1,150,226	20
11/15/2001	11/15/2031	11/15/2001	11/15/2031	300,000,000	23,100,000	21
						22
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	23
						24
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	25
						26
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	8,362,083	27
						28
01/22/1996	01/15/2006	01/22/1996	01/15/2006		238,000	29
01/10/1992	01/10/2007	01/10/1992	01/10/2007	5,724,000	439,031	30
06/09/1995	06/01/2007	06/09/1995	06/01/2007	100,000,000	6,625,000	31
						32
				4,086,372,000	245,313,780	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	7.43% Series E Medium-Term Notes due Sept. 11, 2007	2,000,000	15,530
2	7.22% Series E Medium-Term Notes due Sept. 18, 2007	2,500,000	19,412
3	7.27% Series E Medium-Term Notes due Sept. 24, 2007	4,000,000	31,059
4	6.375% Series H Medium-Term Notes due May 15, 2008	200,000,000	1,416,179
5			644,000 D
6	7.00% Series H Medium-Term Notes due Jul. 15, 2009	125,000,000	1,976,904
7			451,250 D
8	9.15% Series C Medium-Term Notes due Aug. 9, 2011	8,000,000	75,327
9	8.95% Series C Medium-Term Notes due Sept. 1, 2011	25,000,000	175,398
10	8.95% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	132,118
11	8.92% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	188,318
12	8.29% Series C Medium-Term Notes due Dec. 30, 2011	3,000,000	23,040
13	8.26% Series C Medium-Term Notes due Jan. 10, 2012	1,000,000	7,649
14	8.28% Series C Medium-Term Notes due Jan. 10, 2012	2,000,000	13,297
15	8.25% Series C Medium-Term Notes due Feb. 1, 2012	3,000,000	22,946
16	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
17	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
18	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
19	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
20	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
21	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
22	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
23	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
24	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
25	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
26	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
27	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
28	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
29	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
30			-81,560 P
31	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
32	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
33	TOTAL	4,521,486,000	58,967,468

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
09/11/1992	09/11/2007	09/11/1992	09/11/2007	2,000,000	148,600	1
09/18/1992	09/18/2007	09/18/1992	09/18/2007	2,500,000	180,500	2
09/22/1992	09/24/2007	09/22/1992	09/24/2007	4,000,000	290,800	3
05/12/1998	05/15/2008	05/12/1998	05/15/2008	200,000,000	12,750,000	4
						5
07/15/1997	07/15/2009	07/15/1997	07/15/2009	125,000,000	8,750,000	6
						7
08/09/1991	08/09/2011	08/09/1991	08/09/2011	8,000,000	732,000	8
08/16/1991	09/01/2011	08/16/1991	09/01/2011	25,000,000	2,237,500	9
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,790,000	10
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,784,000	11
12/31/1991	12/30/2011	12/31/1991	12/30/2011	3,000,000	248,700	12
01/09/1992	01/10/2012	01/09/1992	01/10/2012	1,000,000	82,600	13
01/10/1992	01/10/2012	01/10/1992	01/10/2012	2,000,000	165,600	14
01/15/1992	02/01/2012	01/15/1992	02/01/2012	3,000,000	247,500	15
01/20/1993	01/22/2013	01/20/1993	01/22/2013	10,000,000	813,000	16
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	17
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	18
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	19
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	20
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	21
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	22
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	23
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	24
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	25
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	26
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	27
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	28
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	29
						30
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	31
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	32
				4,086,372,000	245,313,780	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
2	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
3	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
4	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
5	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
6	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
7	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
8	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
9	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
10	Subtotal - First Mortgage Bonds	3,708,116,000	43,271,995
11			
12	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
13	Poll Ctrl Revenue Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
14	5-5/8% Lincoln County, WY, Series due Nov. 1, 2021	8,300,000	228,980
15			197,125 D
16	5.65% Emery County, Utah, Series due Nov. 1, 2023	46,500,000	1,624,793
17	5-5/8% Emery County, Utah, Series due Nov. 1, 2023	16,400,000	625,551
18			389,500 D
19	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
20	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
21	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
22	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
23	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
24	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
25	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
26			105,000 D
27	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
28	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
29	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
30	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
31			
32	Pollution Control Revenue Bonds:		
33	TOTAL	4,521,486,000	58,967,468

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	1
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	2
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	3
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	4
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	5
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	6
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	7
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	8
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	9
				3,310,502,000	211,003,080	10
						11
						12
11/17/1994	05/01/2013	11/17/1994	05/01/2013	40,655,000	1,510,788	13
11/15/1993	11/01/2021	11/15/1993	11/01/2021	8,300,000	476,836	14
						15
11/15/1993	11/01/2023	11/15/1993	11/01/2023	46,500,000	2,683,053	16
11/15/1993	11/01/2023	11/15/1993	11/01/2023	16,400,000	942,182	17
						18
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	787,087	19
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	303,210	20
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	4,736,241	21
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	348,015	22
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	572,987	23
01/01/1988	01/01/2014	01/01/1988	01/01/2014	17,000,000	680,353	24
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	600,358	25
						26
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	1,638,402	27
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	359,451	28
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	224,251	29
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	951,207	30
						31
						32
				4,086,372,000	245,313,780	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
3	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
4	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
5	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
6	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A	70,000,000	660,750
7	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1991	45,000,000	872,505
8	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A	50,000,000	422,443
9	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
10	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
11	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
12	6.150% Emery County, Utah, Series due September 1, 2030	12,675,000	556,549
13			178,464 D
14			
15	Subtotal - Pollution Control Revenue Bonds	738,370,000	14,855,040
16			
17			
18			
19	TOTAL ACCOUNT 221	4,446,486,000	58,127,035
20			
21			
22	Reacquired Bonds: (Account 222)		
23			
24			
25	Advances from Associated Companies: (Account 223)		
26			
27			
28			
29	Other Long-Term Debt: (Account 224)		
30	$7.48 Series No Par Serial Preferred Stock	75,000,000	840,433
31			
32	TOTAL ACCOUNT 224	75,000,000	840,433
33	TOTAL	4,521,486,000	58,967,468

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	360,221	2
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	243,299	3
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	867,657	4
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	480,969	5
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	2,966,840	6
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	1,949,456	7
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	2,131,467	8
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	1,897,488	9
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	1,767,407	10
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	1,044,462	11
09/24/1996	09/01/2030	09/24/1996	09/01/2030	12,675,000	779,513	12
						13
						14
				738,370,000	31,303,200	15
						16
						17
						18
				4,048,872,000	242,306,280	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
06/11/1992	06/15/2007	07/01/2003	06/15/2007	37,500,000	3,007,500	30
						31
				37,500,000	3,007,500	32
				4,086,372,000	245,313,780	33

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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			
3	Long-Term Debt Authorized but Unissued		
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
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24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	4,521,486,000	58,967,468

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				4,086,372,000	245,313,780	33

Schedule Page: 256 Line No.: 27 Column: a

On August 10, 2006, PacifiCorp issued $350.0 million of its 6.10% Series of First Mortgage Bonds due August 1, 2036. PacifiCorp used the proceeds for general corporate purposes, including the reduction of short-term debt. State Commission authorizations for this issuance were as follows:

Utah Public Service Commission, Docket No. 06-035-43, Report and Order dated May 3, 2006, amended May 18, 2006.

Oregon Public Utility Commission, Docket No. UF-4215, Order No. 05-258, dated May 9, 2005.

Washington Utilities and Transportation Commission, Docket No. UE-050556, Order No. 2, dated June 14, 2006.

Idaho Public Utilities Commission, Case No. PAC-E-05-5, Order No. 29787, dated May 17, 2005.

Schedule Page: 256.3 Line No.: 30 Column: a

As of December 31, 2006, there were 375,000 shares outstanding ($100 stated value per share) on the $7.48 series subject to the following mandatory redemption requirements: all shares outstanding on June 15, 2007 subject to mandatory redemption on that date.

Schedule Page: 256.4 Line No.: 3 Column: a

For authorization for the issuance of long-term debt ($1,000,000,000 authorized; $ 350,000,000 available as of December 31, 2006), refer to page 104, *Important Changes During the Year*, ITEM 6, of this Form No. 1

Authorization for the issuance of pollution control revenue bonds ($125,000,000 authorized; $79,225,000 available as of December 31, 2006) is as follows:

Oregon Public Utility Commission, Docket No. UF-4128, Order No. 95-518, dated May 25, 1995.

Washington Utilities and Transportation Commission, Docket No. UE-950490, dated May 24, 1995.

Idaho Public Utilities Commission, Docket No. PAC-S-95-2, Order No. 26039, dated June 13, 1995.

For additional information regarding long-term debt, refer to page 104, *Important Changes During the Year*, ITEM 6, of this Form No. 1.

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(Next Page is: 261)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	307,934,288
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	429,119,468
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,021,472,373
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	444,401,131
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	933,650,459
26	State Tax Deductions	13,207,381
27	Federal Tax Net Income	367,267,158
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	128,543,505
31	Federal Accrual to Return Adjustments	13,047,764
32	Tax Reserve Changes	-723,981
33	Stock Options to APIC	9,721,304
34	Wind Credits	-14,562,839
35	Excess Loss	-4,013,753
36	Misc. Reclass	-390,395
37		
38	Federal Income Tax Accrual	131,621,605
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 8 Column: a

Particulars (Details)		Amount
Contributions in Aid of Construction	$	80,878,131
Highway Relocation		19,225,228
FAS 133 Derivatives - Current		77,881,869
WA Rate Refund		8,862
Oregon Gain on Sale		104,292
Oregon Share of Hermiston		192,764
FAS 133 Derivatives - Book Unrealized Gain/Loss		241,334,773
Unearned Joint Use Pole Contact Revenue		1,896,864
MCI FOG Wire Lease		558,678
FAS 115 Unrealized Gain/Loss		5,206,175
Equity Earnings in Subsidiaries		1,831,832
Total	$	429,119,468

Schedule Page: 261 Line No.: 13 Column: a

Particulars (Details)		Amount
Federal/State Income Tax	$	157,319,375
Other A/R Bad Debt Write-offs		4,229,804
Mandatory Redeemable Preferred Stock - FAS 150		3,652,930
Meals & Entertainment		1,522,263
Penalties		6,233,819
Penalties - PMI		17,221
Lobbying Expenses		2,820,552
Meals & Entertainment - Bridger Coal		29,325
MEHC Insurance Services - Premium		5,744,651
Non-deductible Executive Comp/ Excise Tax		1,603,395
Non-deductible Parachute Payment - 280G		8,783,014
PMI Fuel Tax Cr		34,374
Scottish Power UK Management Fee		1,645,089
Excess Loss Account Triggers - PPW		12,013,268
30% Capitalized Labor Costs for Powertax Input		8,903,699
Book Depreciation		413,750,864
Book Amortization - Abandoned Proj. - Lease Rights		492,336
Book Amort. - Abandoned Proj. - Lease Rental		30,008
Tax vs Book Depreciation - PMI		12,149,565
AFUDC - Equity		8,794,500
Avoided Costs		39,978,480
Acquisition Adjustment Amort		5,479,360
ADR Repair Allowance 3115		75,000
Cholla SHL (APS Tax Lease)		570,327
Book Cost Depletion - Addback		2,419,022
May 2000 Transition Plan Costs - OR		6,872,283
May 2000 Transition Plan Costs - ID		462,486
May 2000 Transition Plan Costs - UT		2,147,630
May 2000 Transition Plan Costs - WYE		1,291,432
May 2000 Transition Plan Costs - WYW		228,514
Glenrock Excluding Reclamation - UT		2,279,199
FAS 87/88 Pension Write-off - UT rate order		5,528,274
98 Early Retirement - OR rate order		6,434,657
Environmental Costs - WA		352,276

Cholla Plt Transact Costs - APS Amort	1,642,607
WA Disallowed Colstrip #3 - Write-off	91,329
Def Reg Asset - OR Def Net Power Costs	13,585,063
IDAI Costs - direct access	582,933
P&M Strike Amortization - UT	424,221
Contra - RTO Grid West N/R Allowance	1,131,721
Contra RTO Grid West N/R w/o - WA	211,234
Weatherization	6,516,818
Trojan Decommissioning Costs - Regulatory	2,601,223
Income Tax Audit Pymt	1,512,123
SB 1149 - Related Regulatory Assets	7,701,526
Post Merger Loss - Reacq Debt - Addback	9,141,678
Y2K Expense - OR	247,842
Noell Kempf CAP - UT	16,256
Trail Mountain Mine Closure	3,687,988
Trail Mountain Unrecovered Inventory	5,304,104
Prepaid Insurance - IBEW 157 Contingency Reserve	318,873
Prepaid Taxes - OR PUC	1,768,829
Prepaid Taxes - WY PSC	226,079
Pollution Control Facility (Book v. Tax Amort)	572,556
TGS Buyout	27,079
Lakeview Buyout	75,740
Joseph Settlement	240,416
Hermiston Swap	944,252
Energy Trading Derivatives - Current	53,982,762
SPI Investment	7,575,454
WA State Transition Costs	657,375
Fifth Cogen Settlement	333,060
ARO Reg Liabilities	505,868
Non-ARO Liability - Reg Liability	8,726,702
Reg Liability BPA Balancing Accounts	4,458,870
Reg Liab - OR Balance Consol	656,883
OR Reg Asset/Liability Consolidation	115,622
Property Insurance	397,429
West Valley Lease Reduction - WA	342,758
West Valley Lease Reduction - CA	78,145
West Valley Lease Reduction - ID	274,125
West Valley Lease Reduction - WY	608,494
West Valley Lease Reduction - UT	1,364,461
A&G Credit - WA	385,804
A&G Credit - CA	125,169
A&G Credit - ID	277,319
A&G Credit - WY	619,940
Vacation Accrual - Cash Basis (2.5 mos)	1,549,767
Accrued Retention Bonus	256,794
FAS 106 Accruals - Cash Basis	18,509,967
Pension / Retirement Accrual - Cash Basis	9,162,032
SERP Accrual - Cash Basis	6,194,743
Accrued CIC Severance	25,375,997
Steam Rights Blundell Geothermal	1,956,450
FAS 143 ARO Liability	17,512,140
Distribution O&M Amort of Write-off	36,261
M&S Inventory Write-off	551,230

R & E - Sec. 174 Deduction		10,892,694
Bear River Settlement Agreement		929,518
Other Environmental Liabilities		1,254,402
Duke/Hermiston Contract Renegotiation		3,428,226
BPA Conservation Rate Credit		428,752
N. Umpqua Settlement Agreement		1,739,756
Umpqua Settlement Agreement		1,027,734
Idaho Customer Balancing Account		7,776,638
Trail Mountain Accrued Liabilities		1,204,560
Misc. Current and Accrued Liability		2,398,062
California Public Utility Commission Fee		23,999
Reverse Accrued Final Reclamation		60,384
PMI Devt Cost Amort		12,152
Microsoft Software License Liability		1,064,748
Aquila Weather Hedge		22,370,090
FAS 112 Book Reserve		3,275,761
Centralia Sale		3,993,949
LTIP Performance Share Awards		1,527,413
Bridger Coal Company Reclamation Trust Earnings - PMI		12,953,110
Vacation Accrual - PMI		20,870
Merger Credits - OR		36,452
Total	$	1,021,472,373

Schedule Page: 261 Line No.: 18 Column: a

Particulars (Details)	Amount	
Utah Deferred Comp / COLI	$	7,111,632
MEHC Insurance Services - Receivable		8,148,582
Tax Exempt Interest (No AMT)		1,551
Bridger Coal Tax Exempt Interest Income		399,037
Dividend Received Deduction		831,437
PMI Overriding Royalty		30,937
Regulatory Asset - Net FAS 133		322,133,246
RTO Grid West Note Receivable - w/o - WA		211,234
Centralia Gain Give Back - OR		14,843,043
OR Rate Refunds		4,527
CA - California Alternative Rate for Energy Program (CARE)		1,389,730
FAS 158 Pension Liability		75,600,000
FAS 158 Post-Retirement Liability		11,256
Accrued Royalties		292,692
Centralia Give Back - WA		968,141
SMUD Revenue Imputation - UT Reg Liab		7,018,525
FAS 115 Mark to Market Accrual - Bridger - Reclass		5,206,175
CA Refund		199,386
Total	$	444,401,131

Schedule Page: 261 Line No.: 25 Column: a

Particulars (Details)	Amount	
Non Deductible Expenses	$	1,692,027
Tax Percentage Depletion - Deduction		13,113,599
PPL Pre - 1943 Preferred Stock Div - Deduction		428,810

Trapper Mine Dividend Deduction	1,077,170
SPI 404(k) Contribution	3,594,149
2004 JCA - Qualified Production Activities Deduction (3%)	6,375,720
Medicare Subsidy	18,099,000
Bridger Coal Company Depletion - PMI	6,165,000
Tax Depreciation	476,305,618
Depreciation (Tax Depreciaiton M-1)	12,719,787
Capitalized Depreciation	8,136,178
AFUDC - Debt	20,873,557
AFUDC	30,652,231
Basis Intangible Difference	9,023,039
Gain / (Loss) on Prop. Disposition	15,789,551
Coal Mine Development	5,362,699
Coal Mine Extension	1,256,004
Removal Costs	39,777,026
Coal Mine Development - 30% Amortization	1,361,641
Cholla SHL - GE Lease (Tax Int. - Tax Rent)	2,014,244
Malin SHL (Tax Int. - Tax Rent)	5,360,254
ARO - reclass to ARO liabilities	820,790
ARO - reclass to reg assets/liability & ARO liability	8,726,702
Book Gain/Loss on Land Sales	148,892
Tax Percentage Depletion - Deduction	2,985,138
Ptax NOPAs	5,397,852
ARO Reg Assets	17,197,218
Environmental Clean-up Accrual	7,223,182
Wyoming PCAM Def Net Power Costs	2,554,006
SB 1149 Costs	1,076,559
Deferred Intervener Funding Grants	507,754
781 Shopping Incentive	747,938
Trail Mountain	600,163
Coal Pile Inventory Adjustment	1,246,225
Prepaid Taxes - UT PUC	886,715
Prepaid Taxes - ID PUC	78,441
Other Prepaid	1,654,992
Prepaid Taxes - Property Taxes	24,623,060
Sales & Use Tax Accrual	133,639
WY Joint Water Board Reserve - Deduction	525,000
Wasach Workers Comp Reserve	591,043
Roll (not Ptax) 99-00 RAR	405,226
Reg Liability - UT Home Energy Lifeline	2,039,592
Reg Lability - WA Low Energy Program	228,442
A&G Credit - OR	2,305,390
Oregon UE 134 Power Cost	885,080
Bonus Liability - Electric - Cash Basis (2.5 mos)	9,313,224
Deferred Compensation Accrual - Cash Basis	924,079
Pension / Retirement Accrual - Cash Basis	34,068,795
SERP Accrual - Cash Basis	268,921
Severance Accrual - Cash Basis	2,621,675
Executive Trust Comp Reduction Plan - SPI Stock	7,575,454
Steam Rights Blundell Geothermal Tax Depreciation Deduction	1,679,916
Sec. 263A Inventory Change - PMI	1,257,404
Bad Debts Allowance - Cash Basis	27,492,096
Amort of Projects - Klamath Engineering	11,240

Def Reg Asset - Transmission Srvc Deposit		107,528
Def Reg Asset - Foote Creek Contract		240,870
Min. Pension Liability Adjustment		168
Deferred Regulatory Expense		22,938
Tenant Lease Allow - PSU Call Cntr		42,907
Misc Def Dr - Prop Damage Repairs		28,527
Amort of Debt Disc & Exp		148,205
Special Assessment - DOE		67,594
Oregon LIC Bid Liability Reserve		238,000
Purchase Card Trans Provision		957,074
Misc. Deferred Credits		1,971,794
NW Power Act - WA		727,530
Redding Contract - Prepaid		962,493
Legal Reserve		2,002,640
Injuries and Damages Accrual - Cash Basis		764,572
Amort NOPAs 99-00 RAR		343,582
Coal Mine Development - PMI		804,395
Bridger Coal Company Underground Mine Cost Depletion		31,694
Bridger Coal Company Extraction Taxes Payable - PMI		774,504
Bonus Accrual - PMI		28,334
U of WY Contract Amort - Prepaid		3,071,211
Reg Assets/Reg Liabilities - Total		43,120,636
Bogus Creek Settlement		118,000
PacifiCorp Stock Incentive Plan		11,694,777
PacifiCorp Executive Stock Option Plan		17,401,339
Total	$	933,650,459

Schedule Page: 261 Line No.: 38 Column: b

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"). PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

At December 31, 2005, PacifiCorp kept its accounting records on a fiscal-year basis for the Securities and Exchange Commission (the "SEC") financial reporting purposes. The fiscal year end was March 31. Annual fiscal year end tax adjustments were performed in March. In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31.

Names of group members who will file a consolidated Federal Tax Return:

Under ScottishPower:
PacifiCorp Holdings, Inc. (Common US Parent)

PacifiCorp Holdings, Inc. Sub-Group:
Pacific Klamath Energy, Inc.
PacifiCorp
PacifiCorp Group Holdings Company
PPM Energy, Inc.
Scottish Power Finance (US), Inc.

PacifiCorp Group Holdings Company Sub-Group:
Leblon Sales Corporation

PacifiCorp Sub-Group:
Centralia Mining Company
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.
PacifiCorp Environmental Remediation Company
PacifiCorp Future Generations, Inc.
PacifiCorp Investment Management, Inc.

New Energy Holdings I, Inc.
PACE Group, Inc.
PacifiCorp Development Company
PacifiCorp Energy Ventures, Inc.
PacifiCorp Financial Services
PacifiCorp International Group Holdings Company
PacifiCorp Trans, Inc.
PFI International, Inc.

PacifiCorp Financial Services, Inc. Sub-Group:
Birmingham Syn Fuel I, Inc.
Hillsborough Leasing Services, Inc.
Pacific Devlopment (Property), Inc.
Pacific Harbor Capital, Inc.
PCC Holdings, Inc.
PHC Properties Corporation

PPM Energy, Inc. Sub-Group:
Atlantic Renewable Energy Corporation
Enstor, Inc.
PPM Colorado Wind Ventures, Inc.

With respect to members of the PHI Sub-Group, PHI required all subsidiaries to pay to or receive from PHI an amount of tax based primarily on the stand-alone method of allocation. The computation includes all tax benefits from tax deductions stemming from cost borne by utility customers.

Under MEHC:
PPW Holdings LLC Sub-Group:
PacifiCorp

PacifiCorp Sub-Group:
Centralia Mining Company
Energy West Mining Company
Glenrock Coal Company
Intermountain Geothermal Company
Interwest Mining Company
Pacific Minerals, Inc.
PacifiCorp Environmental Remediation Company
PacifiCorp Future Generations, Inc.
PacifiCorp Investment Management, Inc.
Steam Reserve Corporation

MEHC Sub-Group:
Academy of Real Estate, Inc.
Alaska Gas Transmission Company, LLC
Allerton Capital, Ltd.
American Pacific Finance Co.
American Pacific Finance Co. II
Arizona Home Services, LLC
BG Energy Holding Co., LLC
BG Energy, LLC
CalEnergy Company, Inc.
CalEnergy Generation Operating Company
CalEnergy Holdings Inc.
CalEnergy Imperial Valley Co., Inc.
CalEnergy International Services, Inc.
CalEnergy International, Inc.
CalEnergy Minerals Development LLC
CalEnergy Minerals LLC
CalEnergy Pacific Holdings Corp.
CalEnergy UK, Inc.
Capitol Intermediary Company
Capitol Land Exchange, Inc.
Capitol Title Company
CBEC Railway, Inc.
CBS Home Real Estate Company
CBS Home Relocation Services, Inc.
CBSHOME Real Estate of Iowa, Inc.
CE Administrative Services, Inc.
CE Electric (NY), Inc.
CE Electric, Inc.
CE Exploration Co.
CE Geothermal, Inc.
CE Geothermal, LLC
CE Indonesia Geothermal, Inc.
CE International Investments, Inc.
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Power, Inc.

MEHC Sub-Group (continued):

CE Power, LLC
CE Resources, LLC
CE/TA LLC
Champion Realty, Inc.
Chancellor Insurance Services, Inc.
Cimmred Leasing Company
Community Diversified Investments, Inc.
Cordova Funding Corporation
Dakota Dunes Development Company
DCCO, Inc.
Edina Financial Services, Inc.
Edina Realty Referral Network, Inc.
Edina Realty Relocation, Inc.
Edina Realty Title, Inc.
Edina Realty, Inc.
Esslinger-Wooten-Maxwell, Inc.
FFR, Inc.
First Realty, Ltd.
First Reserve Insurance, Inc.
For Rent, Inc.
HMSV Financial Services, Inc.
HN Heritage Title Holdings, LLC
HN Insurance Holdings, LLC
HN Mortgage, LLC
HN Real Estate Group, LLC
HN Real Estate Group, N.C., Inc.
HN Referral Corporation
HomeServices Financial Holdings, Inc.
HomeServices Financial- Iowa, LLC
HomeServices Financial, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc.
HomeServices of California, Inc.
HomeServices of Florida, Inc.
HomeServices of Iowa, Inc.
HomeServices of Kentucky, Inc.
HomeServices of Nebraska, Inc.
HomeServices of Nevada, Inc.
HomeServices of the Carolinas, Inc.
HomeServices Pacific Northwest, Inc.
HomeServices Relocation, LLC
HSR Equity Funding, Inc.
Huff Commercial Group, LLC
Huff Insurance Group, LLC
Huff, Jim Realty, Inc.
Huff-Drees Realty, Inc.
IMO Company, Inc.
InterCoast Capital Company
InterCoast Energy Company
InterCoast Power Company
InterCoast Sierra Power Company
Intermountain Geothermal Co.
Iowa Realty Company, Inc.
Iowa Realty Insurance Agency, Inc.
Iowa Title Company, Inc.
IWG Co. 8
J.D. Reece Mortgage Company
J.S. White Associates, Inc.
JBRC, Inc.
Jenny Pruitt & Associates
JP & A, Inc.
JRHBW Realty, Inc.
Kansas City Title, Inc.
Kentucky Residential Referral Services, LLC
Kern River Funding Corporation
Kern River Gas Transmission Company
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Larabee School of Real Estate & Insurance, Inc.
M & M Ranch Acquisition Company, LLC
M & M Ranch Holding Company, LLC
Magma Generating Co. I
Magma Generating Co. II
MEC Construction Services Co.
MEHC Alaska Holding 1, LLC
MEHC Alaska Holding 2, LLC
MEHC Insurance Services, Ltd.
MEHC Investment, Inc.
MHC Investment Company
MHC, Inc.
Mid-America Referral Network, Inc.
MidAmerican Commercial Real Estate Services, Inc.
MidAmerican Energy Company
MidAmerican Energy Holdings Company
MidAmerican Energy Machining Services, LLC
MidAmerican Funding LLC
MidAmerican Services Company
MidAmerican Transmission, LLC
Midland Escrow Services, Inc.
Midwest Capital Group, Inc.
Midwest Gas Company (inactive)
Mortgage South, LLC
MWR Capital, Inc.
Nebraska Land Title & Abstract Co
NNGC Acquistion, LLC
Northern Aurora, Inc.
Northern Natural Gas Company
Pickford Escrow Company, Inc.
Pickford Golden State Member, LLC
Pickford Holdings, LLC
Pickford Real Estate, Inc
Pickford Services Company, Inc.
Plaza Financial Services, LLC

MEHC Sub-Group (continued):

Plaza Mortgage Services, LLC
PPW Holding LLC
Preferred Carolinas Realty, Inc.
Preferred Carolinas Title Agency, LLC
Professional Referrral Organization, Inc.
Quad Cities Energy Company
Real Estate Links, LLC
Real Estate Referral Network, Inc.
Reece & Nichols Alliance, Inc.
Reece & Nichols Realtors, Inc.
Referral Company of North Carolina, Inc.
RHL Referral Company, LLC
Roberts Holding Company, Inc.
Roy H. Long Realty Company, Inc.
Salton Sea Minerals Corp
San Diego PCRE, Inc.
Semonin Realtors, Inc.
Southwest Relocation, LLC
The Escrow Firm
The Referral Company
Title South, LLC
Trinity Mortgage Partners, Inc
TTP, Inc. of South Dakota
Two Rivers, Inc.
United Settlement Services, LLC
Woods Bros. Realty, Inc.

With respect to members of the MEHC Sub-Group, MEHC requires all subsidiaries to pay to or receive from MEHC an amount of tax based primarily on the stand-alone method of allocation. The computation includes all tax benefits from tax deductions stemming from cost borne by utility customers.

Berkshire Hathaway Inc. Sub-Group:

Berkshire Hathaway Inc. (Common Parent)
21st Communities, Inc.
21st Mortgage Corporation
21st SPC, Inc.
AAS-Lunken, Inc.
Acme Brick Block and Tile, Inc.
Acme Brick Company
Acme Brick DFW, Inc.
Acme Brick Sales Company
Acme Building Brands, Inc.
Acme Investment Company
Acme Management Company
Adalet/Scott Fetzer Company
Agile Mfg, Inc.
Aiken Paint & Decorating Inc. d/b/a Park Avenue Paints
AJF Warehouse Distributors, Inc.
Alachua Tung Oil Company
Albecca Inc.
All Bilt Uniforms
Allegheny Uniforms
Alpha Cargo Motor Exress, Inc.
American Dairy Queen Corporation
American Tile Supply, Inc.
Ardent Risk Services
Ben Bridge Corporation
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Berkshire Hathaway Credit Corp.
Berkshire Hathaway Finance Corporation
Berkshire Hathaway Life Insurance Co. of NE
BH Columbia Inc.
BH Shoe Holdings, Inc.
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHR Inc.
BHSF, Inc.
Birmingham Paint Corporation d/b/a/ Rainbow Paint & Decorating
Blue Chip Stamps
BNJ NetJets, Inc.
Boot Royalty Company
Borsheim Jewelry Company Inc.
Bricker-Mincolla Uniforms
Broker Market Agency, Inc.
Brookwood Insurance Company
Camp Manufacturing Company
Campbell Hausfeld/Scott Fetzer Company
Carefree/Scott Fetzer Company
Central States Indemnity Co. of Omaha
Central States of Omaha Companies, Inc.
CG Service, Inc.

Berkshire Hathaway Inc. Sub-Group:

Chippewa Shoe Company
Claims Services, Inc.
Clayton Commercial Buildings, Inc.
Clayton Homes, Inc.
CMH Capital, Inc.
CMH Hodgenville, Inc.
CMH Homes, Inc.
CMH Insurance Agency, Inc.
CMH Manufacturing West, Inc.
CMH Manufacturing, Inc.
CMH of KY, Inc.
CMH Parks, Inc.
CMH Services, Inc.
CMH Set and Finish, Inc.
Cologne Services Corporation
Columbia Insurance Company
Command Uniforms
Commonwealth Uniforms Inc.
Continental Divide Insurance Co.
Cornhusker Casualty Company
CORT Business Services Corporation
Crescent Paint & Decorating Inc.
Criterion Insurance Agency
Crowley Garment Mfg Co Inc.
Crowley Shirt Mfg Co Inc.
CSI Life Insurance Company
CTB Credit Corp.
CTB International Corp.
CTB IP, Inc.
CTB MN Investments Co. Inc.
CTB, Inc.
Cypress Insurance Company
Dairy Queen Corporate Stores, Inc.
Dairy Queen of Georgia, Inc.
Denver Brick Company
Dexter Shoe Company
DQ Funding Corporation (formerly DQ Overseas Corp.)
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
Edmonds Material and Equipment Co.
Elm Street Corporation
Eureka Brick and Tile Company
Executive Jet Europe, Inc.
Executive Jet Management, Inc.
Expertos en Administracion, S.A. de C.V.
Fairfield Insurance Co.
Faraday Capital Limited
Farriors, Inc.
Fayette Cotton Mill, Inc.
Financial Services Plus, Inc.
First Berkshire Hathaway Life Insurance Company
FlightSafety Capital Corp.
FlightSafety China, Inc.
FlightSafety Development, Inc.
FlightSafety International Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
FlightSafety Texas, Inc.
Floors Inc.
Footwear Investment Company
Forest River Housing, Inc.
Forest River Warranty Company
Forest River, Inc.
France/Scott Fetzer Company
Freedom Warehouse Corp.
Fruit of the Loom Caribbean, Inc.
Fruit of the Loom Texas, Inc.
Fruit of the Loom Trading Company
Fruit of the Loom, Inc.
Fruit of the Loom, Inc.
FSI Delaware Holding Corp.
FTL Regional Sales Co., Inc.
FTL Sales Company, Inc.
Fulton Manufacturing Company
Garan Central America Corp.
Garan Incorporated
Garan Manufacturing Corp
Garan Services Corp
Gateway Underwriters Agency, Inc.
GEICO Casualty Company
GEICO Corporation
GEICO General Insurance Company
GEICO Indemnity Company
GEICO Products, Inc.
Gen Plus Managers, Inc.
Gen Re Intermediaries
General Re Assets Investment (I), Inc.
General Re Assets Investment (II), Inc.
General Re Assets Investment (III), Inc.
General Re Bannockburn, Inc.
General Re Corporate Finance, Inc.
General Re Corporation
General Re Financial Products Corporation
General Re Financial Products Japan, Inc.
General Re Funding Corporation
General Re Investment Holdings Corporation
General Re New England Asset Management
General Re Securities Corporation
General Re Services Corporation
General Re Strategic Solutions

Berkshire Hathaway Inc. Sub-Group:
General Reinsurance Corporation
General Star Indemnity Company
General Star Management, Company
General Star National Insurance Company
Genesis Indemnity Insurance Company
Genesis Insurance Company
Genesis Professional Liability Underwriters
Genesis Underwriting Management Company
GenRe Gisbourne LLC
GMK, Ltd.
Golden Skillet International, Inc.
Government Employees Financial Corporation
Government Employees Insurance Company
GRD Corporation
GRD Global, Inc.
GRD Holdings Corporation
Griffey Uniforms
H.H.Brown Shoe Company, Inc.
H.H.Brown Shoe Technologies, Inc.
H.J. Justin and Sons, Inc.
Halex/Scott Fetzer Company
Hall of Fame Paint Supply Inc.
Hardy Frames, Inc.
Harris Uniforms
Harrison Uniforms
HDS Redevelopment Corporation
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Income Trust No 1
Income Trust No 2
Indecor Group Inc. d/b/a J.C.Licht Company
Innovative Building Products, Inc.
Insurance Counselors of Kentucky,Inc.
Insurance Counselors of Nevada, Inc.
Insurance Counselors of Texas,Inc.
Insurance Counselors,Inc.
Insurance Management Services, Inc.
International Dairy Queen, Inc.
International Insurance Underwriters,Inc.
Isabela Shoe Corporation
J. S. Justin, Inc.
Janovic/Plaza Inc.
Johns Manville
Johns Manville China, LTD.
Johns Manville Contracting Services, Inc.
Johns Manville Corporation
Jordan's Furniture, Inc.
Justin Belt Company, Inc.
Justin Boot Company
Justin Brands, Inc.
Justin Industries, Inc.
Kale Uniforms
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kay Uniforms
Kleberg Holdings, Inc.
Leesburg Knitting Mills, Inc.
Leesburg Yarn Mills, Inc.
M & C Products, Inc.
Macro Retailing, Inc.
Mapletree Transportation, Inc.
MarineSafety International, Inc.
Martin Manufacturing Company
Martin Mills, Inc.
Maryland Ventures, Inc.
McCain Uniform Company Inc.
McLane Company, Inc.
McLane Eastern, Inc.
McLane Express, Inc.
McLane Foodservice, Inc.
McLane Mid-Atlantic, Inc.
McLane Midwest, Inc.
McLane Minnesota, Inc.
McLane New Jersey, Inc.
McLane Southern, Inc.
McLane Suneast, Inc.
McLane Western, Inc.
Medical Protective Corporation
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
Merit Distribution Services, Inc.
Metro Uniforms
Micro Retailing, Inc.
MiTek Framings, Inc.
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek, Inc.
MMX Corporation
Moore's Investment Corp.
Mount Vernon Fire Insurance Company
Mountain View Marketing, Inc.
MS Property Company
MT Sub, Inc.
National Fire & Marine Insurance Co.
National Indemnity Company
National Indemnity Company of Mid-America
National Indemnity Company of the South
National Liability & Fire Insurance Co.
National Re Corporation
National Reinsurance Corporation
Nationwide Uniforms
Nebraska Furniture Mart, Inc.

Berkshire Hathaway Inc. Sub-Group:

NetJets Aviation Inc.
NetJets Inc.
NetJets International Inc.
NetJets Large Aircraft, Inc.
NetJets Leasing, Inc.
NetJets M E Inc.
NetJets Sales Inc.
NetJets Services Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
Nick Bloom Uniforms
NJ Executive Services Inc.
NJA Jets Inc.
NJI Sales Inc.
NJI, Inc.
Nocona Boot Company
North Star Reinsurance Corporation
North Star Syndicate, Inc.
Northern States Agency, Inc.
Northland/Scott Fetzer Company
Oak River Insurance Company
OBH Inc.
OCSAP, Ltd.
OMS Retail Services, Inc.
Opis Realty Co.
Orange Julius of America
Paint & Decorating Depot Inc.
Paint Rental Associates Inc.
Paint Town Inc.
Pima Uniforms
Pinnacle Paint & Decorating, Inc.
Plaza Financial Services Company
Plaza Investment Managers, Inc.
Plaza Paint & Decorating Centers Inc.
Plaza Resources Company
Portland Gold Corp. d/b/a/ Maine Paint Service
Precision Brand Products, Inc.
Precision Steel W/h-Charlotte S/C
Precision Steel Warehouse, Inc.
Pro Installations, Inc.
Professional Datasolutions, Inc.
Queen Carpet Corporation
R.C.Willey Home Furnishings
Rabun Apparel, Inc.
Rainbow State Paint & Decorating Inc.
Redwood Fire and Casualty Insurance Co.
Rentco Trailer Corporation
Republic Insurance Company
Resolute Management Inc.
Ringwalt & Liesche Co
Riverside Paint & Decorating, Inc.
Robert f. deCastro Inc.
Roberts Men's Shop
Safe Driver Motor Club, Inc.
Salado Sales, Inc.
Sandy Paint & Decorating Inc.
Scott Fetzer Company
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
Seattle Paint Supply, Inc.
See's Candies, Inc.
See's Candy Shops, Inc.
Seventeenth Street Realty, Inc.
Shaw Contract Flooring Installation Services, Inc.
Shaw Contract Flooring Services, Inc.
Shaw Contract Properties, Inc.
Shaw Diversified Services, Inc.
Shaw Financial Services, Inc.
Shaw Floors, Inc.
Shaw Funding Company
Shaw Industries Group, Inc.(formerly Shaw Industries, Inc.)
Shaw Industries, Inc.
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
SHX Flooring, Inc.
SHX Leasing, Inc.
Silver State Uniforms
Simon's Incorporated
Sofft Shoe Company, Inc. (Formerly Lowell Shoe, Inc.)
Sol Frank Uniforms Inc.
Somerset Acres
Southwest Paint & Decorating Inc.
Stahl/Scott Fetzer Company
Star Furniture Company
Stonyridge Trust
Strick Mexicana, S.A.
Technical Coatings Co.
Tekmax, Inc.
The B.V.D. Licensing Corp.
The Eagle Company
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Koskovich Company, Inc.
The Medical Protective Company
The Pampered Chef, Ltd.
The Village Paint Shoppe Inc.
Tony Lama Company
Top Five Club, Inc.
TPC European Holdings, Ltd.
TPC North America, Ltd.
Transco, Inc.
TTI, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Company

Berkshire Hathaway Inc. Sub-Group:
Unified Supply Chain, Inc.
Uniforms of Texas
Union Sales, Inc.
Union Underwear Company, Inc.
Unione Italiana Reinsurance Co.of America, Inc.
United Consumer Financial Service Company
United Direct Finance Inc.
United States Aviation Underwriters, Inc.
United States Liability Insurance Company
Universal Uniforms
Vanderbilt ABS Corp.
Vanderbilt Mortgage & Finance, Inc.
Vanderbilt Property & Casualty Insurance Co., Ltd.
Vanderbilt SPC, Inc.
Virginia Paint Co., Inc.
Visilinx, Inc.
Vision Retailing
Wayne/Scott Fetzer Company
Waynesburg Shirt Company Inc.
Wesco Financial Corporation
Wesco Holdings Midwest, Inc.
Wesco-Financial Insurance Co.
West Virginia Uniforms
Western/Scott Fetzer Company
Wheeler Brick Company, Inc.
Winfield Yarn Mill, Inc. (formerly 2556 Industries, Inc.)
Witt Brick & Supply, Inc.
WMC Corp. f/k/a Woodmarc Corporation
World Book Encyclopedia, Inc.
World Book, Inc.
World Book/Scott Fetzer Company, Inc.
Worldbook.com Inc.
X-L-CO., Inc.
XLI, inc.
XTR, Inc.
XTRA Chassis, Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Intermodal, Inc.
XTRA International Pacific, LTD.
XTRA International, LTD.
XTRA Lease, Inc.
XTRA Mexicana, S.A. de C.V.
XTRA, Inc.
Zuckerbergs Uniforms

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(Next Page is: 262)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	-11,123,864		131,621,605	194,825,942	35,379,254
3	FICA			33,180,366	32,852,795	
4	Unemployment	322,764		371,812	693,404	
5	Unemployment - Energy	17,390		209,531	179,073	
6	Unemployment - Interwest	22,633		2,029	24,405	
7	Excise Tax - Coal	232,466		4,149,827	4,249,803	
8	Subtotal	-10,528,611		169,535,170	232,825,422	35,379,254
9						
10	State:					
11						
12	Arizona:					
13	Property	952,458		1,890,336	1,897,626	
14	Income	-69,739		173,216	465,832	-152,366
15	Subtotal	882,719		2,063,552	2,363,458	-152,366
16						
17	California:					
18	Property			1,678,556	1,678,556	
19	Unemployment			23,511	22,119	
20	Franchise-Income	750,490		469,688	722,179	-413,151
21	Regulatory Commission			47,257	47,257	
22	Use	11,297		241,136	204,054	
23	Local Franchise	637,179		881,314	841,362	
24	Subtotal	1,398,966		3,341,462	3,515,527	-413,151
25						
26	Colorado:					
27	Property	2,230,000		1,486,605	1,964,605	
28	Income	-69,035		102,941	258,280	-90,550
29	Subtotal	2,160,965		1,589,546	2,222,885	-90,550
30						
31	Idaho:					
32	Property	1,723,609		2,521,336	2,775,979	
33	Income	1,103,914		897,924	1,380,624	-789,840
34	KWh	500		25,733	25,733	
35	Unemployment			43,254	41,353	
36	Regulatory Commission			310,524	310,524	
37	Use	1,825		186,878	162,717	
38	Subtotal	2,829,848		3,985,649	4,696,930	-789,840
39						
40						
41	TOTAL	27,310,489	7,683,453	303,689,962	378,439,907	24,450,391

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
	38,948,947	106,778,946			24,842,659	2
352,142	24,571				33,180,366	3
1,172					371,812	4
47,848					209,531	5
257					2,029	6
132,490					4,149,827	7
533,909	38,973,518	106,778,946			62,756,224	8
						9
						10
						11
						12
945,168		1,890,336				13
	514,721	126,354			46,862	14
945,168	514,721	2,016,690			46,862	15
						16
						17
		1,653,010			25,546	18
1,392					23,511	19
	-84,848	342,619			127,069	20
					47,257	21
48,379					241,136	22
677,131		881,314				23
726,902	-84,848	2,876,943			464,519	24
						25
						26
1,752,000		1,485,919			686	27
	314,924	75,092			27,849	28
1,752,000	314,924	1,561,011			28,535	29
						30
						31
1,468,966		2,519,236			2,100	32
	168,626	655,001			242,923	33
500		25,733				34
1,901					43,254	35
					310,524	36
25,986					186,878	37
1,497,353	168,626	3,199,970			785,679	38
						39
						40
21,123,323	51,795,841	216,903,727			86,786,235	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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						
2						
3	Montana:					
4	Property	1,166,308		2,522,165	2,425,273	
5	Corporate License-Income	-128,683		121,608	186,981	-106,970
6	Energy License	60,583		220,218	222,342	
7	Wholesale Energy	42,132		152,507	153,960	
8	Subtotal	1,140,340		3,016,498	2,988,556	-106,970
9						
10	Nevada:					
11	Unemployment			11	11	
12	Subtotal			11	11	
13						
14	New Mexico:					
15	Property	4,534		10,794	9,931	
16	Subtotal	4,534		10,794	9,931	
17						
18	Oregon:					
19	Property		7,486,422	15,620,763	16,245,391	
20	Unemployment			1,083,279	1,054,269	
21	Wilsonville Payroll			2,513	1,864	
22	Regulatory Commission			2,375,865	2,375,865	
23	Excise-Income	12,141,030		5,226,681	11,823,403	-4,591,174
24	City of Portland-Income	178,191		84,549	290,001	-74,372
25	Office of Energy		197,031	400,600	407,138	
26	Tri-Met			1,189,592	828,256	
27	Lane County			3,087	3,087	
28	Franchise	2,765,697		18,175,609	18,135,906	
29	Subtotal	15,084,918	7,683,453	44,162,538	51,165,180	-4,665,546
30						
31	Texas:					
32	Unemployment			36	36	
33	Subtotal			36	36	
34						
35	Utah:					
36	Property	237,460		33,372,117	33,320,984	
37	Income	3,473,553		5,385,074	8,292,943	-4,710,440
38	Unemployment			496,271	478,603	
39	Regulatory Commission			3,236,595	3,236,595	
40	Navajo Nation			2,034	2,034	
41	TOTAL	27,310,489	7,683,453	303,689,962	378,439,907	24,450,391

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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
						2
						3
1,263,200		2,522,165				4
	301,026	88,708			32,900	5
58,459		220,218				6
40,679		152,507				7
1,362,338	301,026	2,983,598			32,900	8
						9
						10
					11	11
					11	12
						13
						14
5,397		10,794				15
5,397		10,794				16
						17
						18
	8,111,050	15,533,930			86,833	19
29,010					1,083,279	20
649					2,513	21
					2,375,865	22
	-953,134	3,812,660			1,414,021	23
	101,633	61,675			22,874	24
	203,569	400,600				25
361,336					1,189,592	26
					3,087	27
2,805,400		18,175,609				28
3,196,395	7,463,118	37,984,474			6,178,064	29
						30
						31
					36	32
					36	33
						34
						35
288,593		30,921,751			2,450,366	36
	4,144,756	3,928,201			1,456,873	37
17,668					496,271	38
					3,236,595	39
		2,034				40
21,123,323	51,795,841	216,903,727			86,786,235	41

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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	Use	312,327		4,091,048	4,106,084	
2	Gross Receipts	2,476,174		3,962,307	3,973,679	
3	Subtotal	6,499,514		50,545,446	53,410,922	-4,710,440
4						
5	Washington:					
6	Property	3,518,835		3,160,339	3,329,174	
7	Unemployment			79,306	77,350	
8	Business & Occupation	2,077		21,390	20,395	
9	Public Utility	538,837		8,327,238	8,145,849	
10	Regulatory Commission			410,193	410,193	
11	Use	-104,603		734,281	598,067	
12	Retailing	29		167	167	
13	Land Tax			55	55	
14	Subtotal	3,955,175		12,732,969	12,581,250	
15						
16	Washington D.C.:					
17	Unemployment			117	117	
18	Subtotal			117	117	
19						
20	Wyoming:					
21	Property	3,489,468		7,648,619	7,555,846	
22	Property - Glenrock	58,024			58,024	
23	Unemployment			138,603	136,155	
24	Other Payroll Taxes			-429	-429	
25	Regulatory Commission			874,005	874,005	
26	Franchise	171,900		1,256,486	1,240,586	
27	Use	93,152		1,437,643	1,391,123	
28	Annual Report			35,352	35,352	
29	Subtotal	3,812,544		11,390,279	11,290,662	
30						
31	Miscellaneous:					
32	Goshute Possessory			6,297	6,297	
33	Sho-Ban Possessory			133,242	133,242	
34	Navajo Possessory	15,909		32,905	32,362	
35	Ute Possessory			9,543	9,543	
36	Crow Possessory	25,627		57,294	82,921	
37	Umatilla			53,423	53,423	
38	Misc. Sales & Use Tax Prov.	28,041		1,023,191	1,051,232	
39	Subtotal	69,577		1,315,895	1,369,020	
40						
41	TOTAL	27,310,489	7,683,453	303,689,962	378,439,907	24,450,391

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)	
297,291					4,091,048	1
2,464,802		3,962,307				2
3,068,354	4,144,756	38,814,293			11,731,153	3
						4
						5
3,350,000		3,031,880			128,459	6
1,956					79,306	7
3,072		21,390				8
720,226		8,327,238				9
					410,193	10
31,611					734,281	11
29		167				12
		55				13
4,106,894		11,380,730			1,352,239	14
						15
						16
					117	17
					117	18
						19
						20
3,582,241		7,644,795			3,824	21
						22
2,448					138,603	23
		-429				24
					874,005	25
187,800		1,256,486				26
139,672					1,437,643	27
		35,352				28
3,912,161		8,936,204			2,454,075	29
						30
						31
		6,297				32
		133,242				33
16,452		32,905				34
		9,543				35
		57,294				36
		53,423				37
		67,370			955,821	38
16,452		360,074			955,821	39
						40
21,123,323	51,795,841	216,903,727			86,786,235	41

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

Federal Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 3 Column: l

Taxes applicable to Other Income & Deductions - 408.2 & 409.2

Schedule Page: 262 Line No.: 4 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 5 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 6 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 7 Column: l

Fuel Inventory - 151

Schedule Page: 262 Line No.: 14 Column: l

State Income Tax - Other Income & Deductions - 409.2

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

Account	Amount
Taxes applicable to Other Income & Deduction - 408.2 & 409.2	$ 23,796
Distribution Rent Expense, Rents - 589	1,750
Total	$ 25,546

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

Various Operations and Maintenance Accounts.

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

State Income Tax - Other Income & Deductions - 409.2

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

Regulatory Commission Expense Account - 928.2

Schedule Page: 262 Line No.: 22 Column: l

Clearing Account - 184.

Schedule Page: 262 Line No.: 27 Column: l

Taxes applicable to Other Income & Deductions - 408.2 & 409.2

Schedule Page: 262 Line No.: 28 Column: l

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 32 Column: l

Taxes applicable to Other Income & Deductions - 408.2 & 409.2

Schedule Page: 262 Line No.: 33 Column: l

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262 Line No.: 35 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262 Line No.: 36 Column: l

Regulatory Commission Expense Account - 928.2

Schedule Page: 262 Line No.: 37 Column: l

Clearing Account - 184.

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

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 11 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 19 Column: l

Account	Amount
Taxes applicable to Other Income & Deduction - 408.2 & 409.2	$ 38,102
Distribution Rent Expense, Rents - 589	48,731
Total	$ 86,833

Schedule Page: 262.1 Line No.: 20 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 21 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 22 Column: l

Regulatory Commission Expense Account - 928.2

Schedule Page: 262.1 Line No.: 23 Column: l

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 24 Column: l

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 26 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 27 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 32 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 36 Column: l

Account	Amount
Taxes applicable to Other Income & Deduction - 408.2 & 409.2	$ 14,400
Construction - 107	2,435,966
Total	$ 2,450,366

Schedule Page: 262.1 Line No.: 37 Column: l

State Income Tax - Other Income & Deductions - 409.2

Schedule Page: 262.1 Line No.: 38 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.1 Line No.: 39 Column: l

Operations and Maintenance Expense - 401 & 402.

Schedule Page: 262.2 Line No.: 1 Column: l

Clearing Account - 184.

Schedule Page: 262.2 Line No.: 6 Column: l

Account	Amount
Taxes applicable to Other Income & Deduction - 408.2 & 409.2	$ 125,329
Distribution Rent Expense, Rents - 589	3,130
Total	$ 128,459

Schedule Page: 262.2 Line No.: 7 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.2 Line No.: 10 Column: l

Regulatory Commission Expense Account - 928.2

Schedule Page: 262.2 Line No.: 11 Column: l

Clearing Account - 184.

Schedule Page: 262.2 Line No.: 17 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.2 Line No.: 21 Column: l

Account	Amount
Taxes applicable to Other Income & Deduction - 408.2 & 409.2	$ 240
Distribution Rent Expense, Rents - 589	3,584
Total	$ 3,824

Schedule Page: 262.2 Line No.: 23 Column: l

Various Operations and Maintenance Accounts.

Schedule Page: 262.2 Line No.: 25 Column: l

Regulatory Commission Expense Account - 928.2

Schedule Page: 262.2 Line No.: 27 Column: l

Clearing Account - 184.

Schedule Page: 262.2 Line No.: 38 Column: l

Various Operations and Maintenance Accounts.

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(Next Page is: 266)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	52,197,285			411.4	5,789,424	
6							
7	Idaho	974,201			411.4	65,436	
8	TOTAL	53,171,486				5,854,860	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	10%	16,436,574			420	2,065,260	
14							
15	Total Nonutility	16,436,574				2,065,260	
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
46,407,861			5
			6
908,765			7
47,316,626			8
			9
			10
			11
			12
14,371,314			13
			14
14,371,314			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
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			43
			44
			45
			46
			47
			48

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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 (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Cogeneration Bonds - Sunnyside	413,417				413,417
2						
3	Working Capital Deposit DG&T	1,159,359			93,938	1,253,297
4						
5	Working Capital and Coal Pile					
6	Deposits from Provo City	273,000				273,000
7						
8	Working capital deposit from UAMPS	433,000	143	188,000		245,000
9						
10	Reclamation Costs - Trapper Mine	3,533,600			232,882	3,766,482
11						
12	Reclamation Costs - Deseret Mine	744,697	131	190,054		554,643
13						
14	Reclamation Costs - Trail					
15	Mountain Mine	1,146,738				1,146,738
16						
17	Deferred Compensation - PPL	3,241,153	124	761,547		2,479,606
18						
19	Transmission Service Deposit	1,563,098			68,850	1,631,948
20						
21	Def. Credits - Pricing Dispute	2,972,498	447, 589	2,968,309		4,189
22						
23	MCI F.O.G. wire lease	837,603	454	278,925		558,678
24						
25	Redding Contract	5,500,060	456	549,996		4,950,064
26						
27	Foote Creek Contract	1,255,862	142	137,640		1,118,222
28						
29	Environmental Liabilities -					
30	Centralia Plant	483,942	401, 402	329,112		154,830
31						
32	Environmental Liabilities -					
33	Centralia Mine	3,160,578			66,670	3,227,248
34						
35	Wyoming Joint Powers Water					
36	Board Settlement	1,275,000	232	300,000		975,000
37						
38	Compensation Reduction	10,428,974			5,563,665	15,992,639
39						
40	Unearned Joint Use Pole Contract	3,759,453	454	239,170		3,520,283
41						
42	Oregon DSM Loans NPV Unearned	2,017,823	456, 431	328,868		1,688,955
43						
44	Exec Trust Comp Reduction Plan -					
45	SPI Stock	9,069,938	123, 124	9,069,938		
46						
47	TOTAL	61,591,991		17,759,489	17,959,011	61,791,513

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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 (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Miscellaneous Security Deposits	300			22,712	23,012
2						
3	Environmental Liabilities -					
4	Non-Current	2,766,274			6,865,476	9,631,750
5						
6	Deseret Power Security Deposits	511,328			24,397	535,725
7						
8	Deferred Revenue -					
9	Lease Incentives	421,151	931	62,756		358,395
10						
11	Other Deferred Credits - C&T	4,623,145	555	1,883,400		2,739,745
12						
13						
14	Software License Payments				1,064,748	1,064,748
15						
16	Deferred Revenue -					
17	Duke/Hermiston Gas Sale		547	471,774	3,900,000	3,428,226
18						
19	Other Deferred Credits				55,673	55,673
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	61,591,991		17,759,489	17,959,011	61,791,513

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	634,485		334,312
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	634,485		334,312
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)	634,485		334,312
18	Classification of TOTAL			
19	Federal Income Tax	558,580		294,318
20	State Income Tax	75,905		39,994
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						300,173	3
							4
							5
							6
							7
						300,173	8
							9
							10
							11
							12
							13
							14
							15
							16
						300,173	17
							18
						264,262	19
						35,911	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	1,504,205,263	320,378,764	334,809,374
3	Gas			
4	FAS 109	485,147,153		
5	TOTAL (Enter Total of lines 2 thru 4)	1,989,352,416	320,378,764	334,809,374
6	Nonutility	-7,497,530		220,604
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,981,854,886	320,378,764	335,029,978
10	Classification of TOTAL			
11	Federal Income Tax	1,744,769,666	282,052,512	294,951,031
12	State Income Tax	237,085,220	38,326,252	40,078,947
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
	5,068,677			283, 216	63,962,590	1,548,668,566	2
							3
		182	21,049,892			464,097,261	4
	5,068,677		21,049,892		63,962,590	2,012,765,827	5
1,187,496	661,923					-7,192,561	6
							7
							8
1,187,496	5,730,600		21,049,892		63,962,590	2,005,573,266	9
							10
1,045,438	5,045,060		18,531,737		56,310,877	1,765,650,665	11
142,058	685,540		2,518,155		7,651,713	239,922,601	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Regulatory Assets	162,604,656	23,008,044	39,705,422
4				
5	Derivative Contracts			14,587,176
6	PMI Deferred Liabilities	400,396	60,001,551	66,782,496
7	Other Deferred Liabilities	167,897,026	76,989,611	78,881,334
8				
9	TOTAL Electric (Total of lines 3 thru 8)	330,902,078	159,999,206	199,956,428
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	330,902,078	159,999,206	199,956,428
20	Classification of TOTAL			
21	Federal Income Tax	291,315,901	140,858,830	176,036,052
22	State Income Tax	39,586,177	19,140,376	23,920,376
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
2,913,046		190	21,295,875	190	129,560,003	257,084,452	3
							4
114,801,855	59,193,510	219	2,587,527	283	64,502,868	102,936,510	5
	134,187	190	24,944,059	190	31,458,795		6
464,900	462,070		120,791,900	186	22,278,799	67,495,032	7
							8
118,179,801	59,789,767		169,619,361		247,800,465	427,515,994	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
118,179,801	59,789,767		169,619,361		247,800,465	427,515,994	19
							20
104,042,195	52,637,240		149,328,146		218,156,606	376,372,094	21
14,137,606	7,152,527		20,291,215		29,643,859	51,143,900	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 7 Column: a

Other Deferred Liabilities:	Balance At Beginning of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Adjustment Amounts	Balance at End of Year
DTL 205.100 Coal Pile Inventory Adj.	$ 459,937	$ 1,353,489	$ 31,142	$ -	$ -	$ -	$ 1,782,284
DTL 205.200 Coal M&S Inventory Write-Off	833,587	2,004,652	2,838,239	-	-	-	-
DTL 110.100 Book Depletion	-	9,952,313	-	-	-	9,952,313	-
DTL 425.250 TGS Buyout	87,107	-	10,277	-	-	-	76,830
DTL 425.260 Lakeview Buyout	62,962	-	28,743	-	-	-	34,219
DTL 425.280 Joseph Settlement	669,096	-	91,240	-	-	-	577,856
DTL 425.340 Firth Cogen Settlement	126,399	-	126,399	-	-	-	-
DTL 425.320 Umpqua Settlement Agreement	65,017	-	65,017	-	-	-	-
DTL 910.240 Legal Reserve	-	1,002	-	-	-	-	1,002
DTL 210.100 Prepaid Taxes - OR PUC	896,710	826,939	1,498,233	-	-	-	225,416
DTL 210.120 Prepaid Taxes - UT PUC	277,643	438,323	101,806	-	-	-	614,160
DTL 210.130 Prepaid Taxes - ID PUC	29,155	39,848	10,080	-	-	-	58,923
DTL 210.140 Prepaid Taxes - WY PSC	85,800	144,462	230,262	-	-	-	-
DTL 210.160 Prepaid Taxes - OR Property	1,437,274	-	1,437,274	-	-	-	-
DTL 210.180 Prepaid Membership Fees - EEI,WSCC	-	628,086	-	-	-	-	628,086
DTL 210.200 Prepaid Property Taxes	2,712,590	26,195,302	-	-	-	-	28,907,892
DTL 210.000 Prepaid Ins. Cont Reserve	-	126,778	51,864	-	-	-	74,914
DTL 740.100 Post Merger Loss-Reacq. Debt	13,178,566	-	3,469,355	-	-	-	9,709,211
DTL 320.210 R & E - Sec.174 Deduction	16,146,366	2,466,478	7,649,723	-	-	10,963,121	-
DTL 720.600 FAS115 Mark to Mark Accrual	1,903,273	-	234,380	-	-	1,666,811	2,082
DTL 425.360 Hermiston Swap	2,320,763	-	358,352	-	-	-	1,962,411
DTL 730.150 Weather Derivatives	37,339	-	37,339	-	-	-	-
DTL 730.180 Aquila Weather Hedge	10,698,839	-	10,698,839	-	-	-	-
DTL 610.150N NOPA 98 99-00 RAR	17,427	-	17,427	-	-	-	-
DTL 610.065N NOPA 119 99-00 RAR	1,877,041	-	1,877,041	-	-	-	-
DTL 610.005N SEC 174 94-98 & 99-00 RAR	12,124,544	-	12,124,544	-	-	-	-
DTL 610.095 N Roll (not Ptax) 99-00 RAR	283,152	333,461	338,071	-	-	-	278,542
DTL 425.310 Hydro Relicensing Obligation	-	12,364,679	-	-	-	-	12,364,679
DTL 605.710 Reverse Accrued Final Reclass	13,067,991	4,914,010	17,982,001	-	-	-	-
DTL 605.710 Reverse Accrued Final Reclamation	-	9,910,693	-	-	-	-	9,910,693
DTL 135.300 Deferred Comp - ExSop	-	194,841	-	-	-	-	194,841
DTL 415.637 Min. Pension Liability Adj.	9,146,951	1,710,396	1,710,396	-	-	9,146,951	-
DTL 720.900 Min SERP Liab. OCI	298,135	-	596,269	-	(298,134)	-	-
DTL 425.300 Mead Phoenix Availability&T	6,045,169	-	6,045,169	-	-	-	-
DTL 330.100 PollutionControlFacility(Bk	1,147,237	-	217,287	-	-	929,950	-
DTL 605.200 WY Joint Water Board Reserve	-	-	464,900	464,900	-	-	-
DTL 920.120 Investment in SPI	2,874,961	197,237	2,311,994	-	760,204	-	-
DTL 705.190 Oregon Share of Hermiston	73,156	-	73,156	-	-	-	-
DTL 425.380 Idaho Customer Balancing Ac	-	2,793,515	2,793,515	-	-	-	-
DTL Flowthrough Partnership Income	3,058,884	-	3,058,884	-	-	-	-
DTL 505.115 Sales & Use Tax Accrual	-	302,116	302,116	-	-	-	-
DTL 105.4143/165 Basis Diff-Intangibles	1,351,087	-	-	-	-	1,351,087	-
DTL 415.803 RTO Grid West N/R-W/O-WA	-	80,165	-	-	-	-	80,165
DTL 425.205 Misc Def Dr-Prop Damage Repairs	-	10,826	-	-	-	-	10,826
DTL 730.110 FAS 133 Derivatives	64,502,868	-	-	-	-	64,502,868	-
Total	$ 167,897,026	$ 76,989,611	$ 78,881,334	$ 464,900	$ 462,070	$ 98,513,101	$ 67,495,032

Schedule Page: 276 Line No.: 7 Column: g

Account 219
Account 236
Account 282
Account 190

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(Next Page is: 278)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	FAS 109 Regulatory Liability	28,701,959	190	3,157,334		25,544,625
2	OR Gain on Sale of Assets	126,839			36,929	163,768
3	Property Insurance Reserve	3,551,611	228, 924	3,317,199	1,998,702	2,233,114
4	SMUD Revenue Imputation	32,904,888	440, 442	7,449,056	2,570,914	28,026,746
5	Oregon Rate Refund	79,969			2	79,971
6	Utah Home Energy Lifeline	743,760	142	2,584,396	1,832,150	-8,486
7	BPA Washington Balancing Account	3,386,383	440, 442	1,189,701	132,673	2,329,355
8	BPA Oregon Balancing Account	13,963,521	440, 442	792,086	678,756	13,850,191
9	BPA Idaho Balancing Account	4,622,244			3,291,336	7,913,580
10	ARO/Reg Diff - Deer Creek Mine Reclamation	394,400	230	99,802	166,852	461,450
11	ARO/Reg Diff - Trojan Nuclear Plant	947,308	230	113,521		833,787
12	FAS 109 - WA Flow Through	12,959,445			9,381,770	22,341,215
13	West Valley Lease Reduction - WA				342,758	342,758
14	West Valley Lease Reduction - OR		182.3	1,083,689	1,083,689	
15	West Valley Lease Reduction - CA				78,145	78,145
16	West Valley Lease Reduction - ID				274,125	274,125
17	West Valley Lease Reduction - WY				608,494	608,494
18	West Valley Lease Reduction - UT		182.3	85,095	1,449,556	1,364,461
19	A & G Credit - WA				385,804	385,804
20	A & G Credit - OR			1,370,920	1,370,920	
21	A & G Credit - CA				125,169	125,169
22	A & G Credit - ID				277,319	277,319
23	A & G Credit - WY				619,940	619,940
24	Regulatory Liability - Reclass	1,299,592			791,037	2,090,629
25	Washington Low Income Program	146,064	142	805,414	590,476	-68,874
26	FAS 133 - Derivative Net Reg Liability	92,296,078	182.3, 175	92,296,078		
27	Reg Liability - OR Consolidated	2,196,540	456	2,080,916		115,624
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	198,320,601		116,425,207	28,087,516	109,982,910

Schedule Page: 278 Line No.: 24 Column: f

The following is a reconciliation of the regulatory liability reclassification account:

Reclassified from Regulatory Assets to Regulatory Liabilities:		
California DSM Regulatory Asset	$	221,525
Washington DSM Regulatory Asset		1,791,744
Reclassified from Regulatory Liabilities to Regulatory Assets:		
Washington Low Income Program		68,874
Utah Home Energy Lifeline (11)		8,486
	$	2,090,629

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	1,065,628,795	968,845,322
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	917,467,966	858,409,269
5	Large (or Ind.) (See Instr. 4)	828,823,262	775,094,563
6	(444) Public Street and Highway Lighting	18,427,832	17,038,050
7	(445) Other Sales to Public Authorities	16,659,617	17,353,876
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,847,007,472	2,636,741,080
11	(447) Sales for Resale	750,904,692	616,037,278
12	TOTAL Sales of Electricity	3,597,912,164	3,252,778,358
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	3,597,912,164	3,252,778,358
15	Other Operating Revenues		
16	(450) Forfeited Discounts	5,910,738	5,535,245
17	(451) Miscellaneous Service Revenues	6,288,827	7,681,519
18	(453) Sales of Water and Water Power	15,228	
19	(454) Rent from Electric Property	19,392,877	29,072,161
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	76,514,879	143,884,805
22	(456.1) Revenues from Transmission of Electricity of Others	41,246,494	
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	149,369,043	186,173,730
27	TOTAL Electric Operating Revenues	3,747,281,207	3,438,952,088

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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
15,334,601	14,650,121	1,411,602	1,379,654	2
				3
15,397,126	14,768,597	199,474	194,933	4
20,471,544	19,601,466	34,099	34,235	5
149,401	165,692	4,258	4,271	6
444,665	460,326	14	19	7
				8
				9
51,797,337	49,646,202	1,649,447	1,613,112	10
13,656,537	13,274,441			11
65,453,874	62,920,643	1,649,447	1,613,112	12
				13
65,453,874	62,920,643	1,649,447	1,613,112	14

Line 12, column (b) includes $ 177,642,000 of unbilled revenues.

Line 12, column (d) includes 3,217,145 MWH relating to unbilled revenues

Name of Respondent PacifiCorp	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 2006/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 11 Column: f

For a complete list of the number of customers see pages 310-311 Sales for Resale of this Form No. 1.

Schedule Page: 300 Line No.: 11 Column: g

For a complete list of the number of customers see pages 310-311 Sales for Resale of this Form No. 1.

Schedule Page: 300 Line No.: 27 Column: b

	Page 300 Year ended December 31, 2006	Page 304 Year ended December 31, 2006	Variance Year ended December 31, 2006	
Sales of Electricity				
Residential Sales - Account (440)	$ 1,065,628,795	$ 1,065,628,795	$ -	
Commercial and Industrial Sales - Account (442)				
Small (Commercial)	917,467,966	917,467,966	-	
Large (Industrial)	828,823,262	828,823,262	-	(a)
Public Street and Highway Lighting - Account (444)	18,427,832	18,427,832	-	
Other Sales to Public Authorities - Account (445)	16,659,617	16,659,617	-	
Sales to Railroads and Railways - Account (446)	-	-	-	
Interdepartmental Sales - Account (448)	-	-	-	
Total Sales to Ultimate Consumers	2,847,007,472	2,847,007,472	-	
Sales for Resale - Account (447)	750,904,692	-	750,904,692	(b)
Total Sales of Electricity	3,597,912,164	2,847,007,472	750,904,692	
(less) Provision for Rate Refunds - Account (449.1)	-	-	-	
Total Revenues Net of Provisions for Refunds	3,597,912,164	2,847,007,472	750,904,692	
Other Operating Revenues				
Forfeited Discounts - Account (450)	5,910,738	5,910,738	-	
Miscellaneous Service Revenues - Account (451)	6,288,827	6,288,827	-	
Sales of Water and Water Power - Account (453)	15,228	15,228	-	
Rent from Electric Property - Account (454)	19,392,877	19,392,877	-	
Interdepartmental Rents - Account (455)	-	-	-	
Other Electric Revenues - Account (456)	76,514,879	71,465,755	5,049,124	(c)
Revenues from Transmission of Electricity of Others (456.1)	41,246,494	41,246,494	(0)	
Total Operating Revenues	$ 3,747,281,207	$ 2,991,327,391	$ 755,953,816	

(a) The large industrial line on page 300 includes account 442.2 Industrial Sales of $770,600,712 and account 442.3 Irrigation Sales of $58,222,550.

(b) Sales for Resale are not included on page 304 Revenue by Rate Schedule.

(c) Other Electric Revenues on page 300 includes steam sales of $5,049,124 not included on page 304 Revenue by Rate Schedule.

Schedule Page: 300 Line No.: 1 Column: $

The following table is a reconcilation of the unbilled revenue accrual ar December 31, 2006 and the reversal of the December 31, 2005 unbilled revenue accrual.

	December 31, 2006
Current year unbilled revenue accrual	$ 177,642,000
Prior year unbilled revenue accrual reversal	(169,648,000)
Change In Unbilled Revenue Accrual	$ 7,994,000

Schedule Page: 300 Line No.: 1 Column: MWH

The following table is a reconcilation of the unbilled MWH accrual ar December 31, 2006 and the reversal of the December 31, 2005 unbilled MWH accrual.

	December 31, 2006
Current year unbilled MWH accrual	3,217,145
Prior year unbilled MWH accrual reversal	(3,108,165)
Change in MWH Accrual	108,980

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Residential Sales					
2	CA					
3	06CHCK000R-CA RES CHECK M			1		
4	06LNX00102-LINE EXT 80% G		32			
5	06LNX00109-REF/NREF ADV +		769			
6	06NETMT135 - CA RES NET	63	5,556	6	10,500	0.0882
7	06OALT015R-OUTD AR LGT SR	381	66,774	406	938	0.1753
8	06RESD000D-RES SRVC	210,880	18,096,870	20,077	10,504	0.0858
9	06RESDDC7A-CA RES CLEAN A	-425	-36,186			0.0851
10	06RESDDL06-CA LOW INCOME	83,492	6,183,110	7,481	11,161	0.0741
11	06RESDDM9M-MULTI FAMILY	407	32,800	12	33,917	0.0806
12	06RESDDS8M-MULTI FAM SBMET	1,396	105,453	16	87,250	0.0755
13	ACQUISITION COMMITMENT-A and		-63,957			
14	ACQUISITION		-38,737			
15	CA ALT RATE FOR ENERGY		538,151			
16	SMUD REVENUE IMPUTATIONS		83,134			
17	06RESD00DN - CA RES SRVC -	102,853	8,721,246	7,633	13,475	0.0848
18	UNBILLED REV - UNCOLLECTIBLE		5,000			
19	UNBILLED REVENUE	-1,338	-77,000			0.0575
20	ID					
21	07LNX00010-MNTHLY 80%GUAR		976			
22	07LNX00035-ADV 80%MO GUAR		1,762			
23	07LNX00107-SUBDIV ADV+AIC		1,094			
24	07NETMT135 - ID RESIDENTIAL	14	735	1	14,000	0.0525
25	07NETMT135 - ID RES NET		-261			
26	07OALCO007-CUST OWN LIGHT	10	2,054	1	10,000	0.2054
27	07OALT007R-SECURITY AR LG	11	2,970	17	647	0.2700
28	07OALT07AR-SECURITY AR LG	115	26,093	148	777	0.2269
29	07OALT07AR-SECURITY AR LG		-2,216			
30	07RESD0001-RES SRVC	368,703	30,941,591	37,176	9,918	0.0839
31	07RESD0001-RES SRVC		-7,084,935			
32	07RESD0036-RES SRVC-OPTIO	313,097	21,208,470	16,295	19,214	0.0677
33	07RESD0036-RES SRVC-OPTIO		-6,016,464			
34	BPA BALANCING ACCOUNT		-5,711,847			
35	UNBILLED REV - UNCOLLECTIBLE		9,000			
36	ACQUISITION COMMITMENT-A and		-65,980			
37	ACQUISITION		-63,051			
38	UNBILLED REVENUE	-4,411	-274,000			0.0621
39	OR					
40	01CHCK000R-RES CHECK MTR			1		
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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	01COST0004 - 01RESD0004	5,395,788	194,299,986			0.0360
2	01HABIT004 - 01RESD0004	31,367	1,095,727			0.0349
3	01LNX00102-LINE EXT 80% G		2,029			
4	01LNX00105-CNTRCT $ MIN G		46			
5	01LNX00109-REF/NREF ADV +		12,576			
6	01NETMT135-NET METERING		105,730	249		
7	01NETMT135-NET METERING		-25,422			
8	01OALT014R-OUTD AR LGT RE	3,092	383,712	3,157	979	0.1241
9	01OALT014R-OUTD AR LGT RE		-28,782			
10	01PTOU0004 - 01RESD0004	18,613	667,455			0.0359
11	01RENEW004 - 01RESD0004	127,079	4,374,225			0.0344
12	01RESD0004-RES SRVC	82	235,476,494	459,742		2,871.6646
13	01RESD0004-RES SRVC		-56,189,350			
14	01RESD004T - RES Time Option		780,362	1,186		
15	01RESD004T - RES Time Option		-173,449			
16	01UPPL000R-BASE SCH FALL			3		
17	01ZZMERGCR-MERGER CREDITS		-27			
18	ACQUISITION COMMITMENT-A and		-551,819			
19	ACQUISITION		-422,382			
20	BPA BALANCING ACCOUNT		834,153			
21	OR SB408 RECOVERY		3,767,157			
22	SMUD REVENUE IMPUTATIONS		1,017,435			
23	UNBILLED REV - UNCOLLECTIBLE		46,000			
24	UNBILLED REVENUE	-22,435	-1,416,000			0.0631
25	UT					
26	08BLSKY01R-BLUESKY ENERGY		-2			
27	08CFR00001-MTH FACILITY S		1,409			
28	08CHCK000R-UT RES CHECK M			1		
29	08COOLKPRR - Utah Cool Keeper		-37	60,181		
30	08LNX00001-MTHLY 80% GUAR		2,107			
31	08LNX00005-MTHLY MIN GUAR		240			
32	08LNX00013-80% MNTHLY MIN		16,631			
33	08LNX00016 - 80% annual guarantee		1,044			
34	08LNX00108-ANN COST MTHLY		4,921			
35	08MHTP0025-MOBILE HOME &	11,189	671,125	11	1,017,182	0.0600
36	08NETMT135 - Net Metering	505	36,773	76	6,645	0.0728
37	08OALT007R-SECURITY AR LG	2,985	704,242	3,425	872	0.2359
38	08PTLD000R-POST TOP LIGHT	224	16,802	66	3,394	0.0750
39	08RESD0001-RES SRVC	5,922,745	442,343,598	643,905	9,198	0.0747
40	08RESD0002-RES SRVC-OPTIO	2,464	180,980	293	8,410	0.0734
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	08RESD0003-LIFELINE PRGRM	180,986	13,296,086	23,761	7,617	0.0735
2	08RFND1999-UTAH RATE RFND					
3	08UPPL000R-BASE SCH FALL			2		
4	08ZZMERGCR-MERGER CREDITS		8			
5	ACQUISITION		-372,273			
6	SMUD REVENUE IMPUTATIONS		1,015,270			
7	UNBILLED REV - UNCOLLECTIBLE		32,000			
8	UNBILLED REVENUE	18,199	1,692,000			0.0930
9	WA					
10	02LNX00109-REF/NREF ADV +		1,421			
11	02OALT013R-WA OUTD AR LGT	881	110,253	1,292	682	0.1251
12	02OALT013R-WA OUTD AR LGT		-9,947			
13	02OALT015R-WA OUTD AR LGT		55	1		
14	02OALTB15R-WA OUTD AR LGT	322	40,151	1,283	251	0.1247
15	02OALTB15R-WA OUTD AR LGT		-3,296			
16	02RESD0016-WA RES SRVC	1,557,092	97,485,553	98,637	15,786	0.0626
17	02RESD0016-WA RES SRVC		-16,945,045			
18	02RESD0017-BILL ASSISTANC	39,531	2,498,991	2,027	19,502	0.0632
19	02RESD0017-BILL ASSISTANCE		-428,615			
20	02RESD0018-WA 3 PHASE RES	2,805	193,979	101	27,772	0.0692
21	02RESD0018-WA 3 PHASE RES		-30,672			
22	02RESD018X-WA 3 PHASE RES	761	52,118	27	28,185	0.0685
23	02RESD018X-WA 3 PHASE RES		-8,348			
24	02RFNDCENT - CENTRALIA RFND		-90			
25	02ZZMERGCR-MERGER CREDITS		-20			
26	ACQUISITION COMMITMENT-A and		-146,504			
27	ACQUISITION		-126,011			
28	BPA BALANCING ACCOUNT		1,148,662			
29	UNBILLED REV - UNCOLLECTIBLE		10,000			
30	UNBILLED REVENUE	-5,050	-435,000			0.0861
31	WY					
32	05NETMT135 - EXPERIMENTAL	17	1,397	5	3,400	0.0822
33	05OALT015R-OUTD AR LGT SR	1,146	151,231	1,206	950	0.1320
34	05RES00002-WY OPTIONAL	51,197	3,596,489	5,115	10,009	0.0702
35	05RESD0002-WY RES SRVC	749,899	55,873,765	86,645	8,655	0.0745
36	05RESD0003-WY OPTIONAL RE	58,022	3,663,611	5,134	11,302	0.0631
37	05RESD0018-RES 3 PHASE SR	159	11,523	8	19,875	0.0725
38	05RESD0135 - Experimental Partial	20	1,377	5	4,000	0.0689
39	05RESD018X-RES 3 PHASE SR	155	11,135	3	51,667	0.0718
40	05RFNDCENT-CENTRALIA RFND		-4			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report End of 2006/Q4

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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	09LNX00108-ANN COST MTHLY		336			
2	09RESD0201-RES SRVC	38	2,644	17	2,235	0.0696
3	ACQUISITION COMMITMENT-A and		-70,806			
4	ACQUISITION		-67,300			
5	SMUD REVENUE IMPUTATIONS		128,500			
6	09NETMT135 - WY RES NET	17	1,329	2	8,500	0.0782
7	09RESD0002	167	12,350	20	8,350	0.0740
8	UNBILLED REV - UNCOLLECTIBLE		8,000			
9	UNBILLED REVENUE	-11,035	-298,000			0.0270
10	05RESD0002-WY RES SRVC	580	43,084	65	8,923	0.0743
11	05RESD0003-WY OPTIONAL RE	51	3,172	4	12,750	0.0622
12	05RESD0018-RES 3 PHASE SR	4	403	1	4,000	0.1008
13	05UPPL000R-BASE SCH FALL			1		
14	09INVCHG0R-INVEST MNT CHG		3	1		
15	09OALT207R-SECURITY AR LG	94	30,181	103	913	0.3211
16	09RESD0201-RES SRVC	16,129	1,144,121	9,372	1,721	0.0709
17	09RESD0205-RES SRVC ALL E	9,967	633,915	2,238	4,454	0.0636
18	09NETMT135 - WY RES NET	25	1,672	1	25,000	0.0669
19	SMUD REVENUE IMPUTATIONS		21,455			
20	05RES00002-WY OPTIONAL	47	3,243	4	11,750	0.0690
21	09RES00002	30,768	2,143,666	2,224	13,835	0.0697
22	09RESD0002	62,033	4,794,430	9,527	6,511	0.0773
23	09RESD0003 -	235	16,452			0.0700
24	UNBILLED REVENUE	393	60,000			0.1527
25	Less Multiple Billings			-98,796		
26						
27	Total Residential	15,334,601	1,065,628,795	1,411,602	10,863	0.0695
28						
29	COMMERCIAL SALES					
30	CA					
31	06CHCK000N-CA NRES CHECK			2		
32	06GNSV0025-CA GEN SRVC	63,690	6,893,599	6,740	9,450	0.1082
33	06GNSV025F-GEN SRVC-< 20	974	120,543	92	10,587	0.1238
34	06GNSV0A32-GEN SRVC-20 KW	77,582	6,850,059	863	89,898	0.0883
35	06LGSV048T-LRG GEN SERV	71,541	3,895,453	10	7,154,100	0.0545
36	06LGSV0A36-LRG GEN SRVC-O	83,137	6,116,547	196	424,168	0.0736
37	06LNX00102-LINE EXT 80% G		5,704			
38	06LNX00105-CNTRCT $ MIN G		1,092			
39	06LNX00109-REF/NREF ADV +		87,063			
40	06LNX00300 - 80% MONTHLY MIN		1,057			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	06OALT015N-OUTD AR LGT SR	765	135,315	557	1,373	0.1769
2	06RCFL0042-AIRWAY & ATHLE	199	26,236	39	5,103	0.1318
3	06WHSV0031-COMM WTR HEATI	250	22,072	31	8,065	0.0883
4	ACQUISITION COMMITMENT-A and		-47,218			
5	ACQUISITION		-28,598			
6	CA ALT RATE FOR ENERGY		399,872			
7	SMUD REVENUE IMPUTATIONS		61,807			
8	06LNX00103-LINE EXT 80% G		58			
9	06LNX00110-REF/NREF ADV +		6,991			
10	UNBILLED REVENUE	-5,632	-469,000			0.0833
11	ID					
12	07CISH0019-COMM & IND SPA	10,186	722,751	301	33,841	0.0710
13	07GNSV0006-GEN SRVC-LRG P	209,666	12,440,410	909	230,656	0.0593
14	07GNSV0009-GEN SRVC-HI VO	31,272	1,365,675	1	31,272,000	0.0437
15	07GNSV0023-GEN SRVC-SML P	107,882	8,617,981	5,424	19,890	0.0799
16	07GNSV0035-GEN SRVCOPTION	1,830	94,740	2	915,000	0.0518
17	07GNSV006A-GEN SRVC-LRG P	24,319	1,636,674	199	122,206	0.0673
18	07GNSV006A-GEN SRVC-LRG P		-467,316			
19	07GNSV023A-GEN SRVC-SML P	14,779	1,257,011	1,089	13,571	0.0851
20	07GNSV023A-GEN SRVC-SML P		-284,372			
21	07GNSV023F-GEN SRVC SML P	18	2,591	7	2,571	0.1439
22	07LNX00010-MNTHLY 80%GUAR		4,743			
23	07LNX00035-ADV 80%MO GUAR		187,597			
24	07LNX00040-ADV+REFCHG+80%		31,233			
25	07OALT007N-SECURITY AR LG	262	52,415	201	1,303	0.2001
26	07OALT07AN-SECURITY AR LG	10	2,334	15	667	0.2334
27	07OALT07AN-SECURITY AR LG		-190			
28	07LNX00312 - ID LINE EXT		1,593			
29	07LNX00015-ANNUAL 80%GUAR		1,120			
30	07LNX00311 - LINE EXT 80%		4,529			
31	07LNX00020 - ID MONTHLY		573			
32	07LNX00300 - 80% MONTHLY MIN		1,905			
33	ACQUISITION COMMITMENT-A and		-38,359			
34	ACQUISITION		-36,657			
35	BPA BALANCING ACCOUNT		-318,119			
36	UNBILLED REVENUE	481	29,000			0.0603
37	OR					
38	01COST0023, OR GEN SRV, COST	979,702	35,355,701			0.0361
39	01COST0048 - 01LGSV0048	707,417	23,748,484			0.0336
40	01COST023F - OR GEN SRV -	3,237	125,166			0.0387
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	01COSTB023 - OR GEN SRV,	98,304	3,685,949			0.0375
2	01COSTL028, OR LRG SRV, COST	-1,755	-58,018			0.0331
3	01COSTL030 - OR LRG GEN SRV,	989,349	34,612,807			0.0350
4	01COSTS028, OR GEN SERV,	1,945,045	68,034,305			0.0350
5	01COSTS030 - OR GEN SRV CBS >	1,144	40,384			0.0353
6	01GNSB0023 - BPA DISC, < 30 kW		-998,833			
7	01GNSB0023, OR GEN SRV, BPA, <		5,265,134	14,812		
8	01GNSB0028 - OR GEN SRVC,		-1,568,281			
9	01GNSB0028, OR GEN SRV, BPA, >		3,497,961	637		
10	01GNSB023T - OR GEN SRV - TOU		63,149	104		
11	01GNSB023T - OR GEN SRVC,		-15,135			
12	01GNSV0023, OR GEN SRV, < 30	-1	35,142,814	52,531		-35,142.8140
13	01GNSV0028, OR GEN SRV > 30		41,654,362	8,521		
14	01GNSV023F - OR GEN SRV - FLAT	11,525	1,155,979	901	12,791	0.1003
15	01GNSV023M - OR GEN SRV,	64	3,965	1	64,000	0.0620
16	01GNSV023T, OR GEN SRV, TOU		147,522	221		
17	01HABT0023, OR HABITAT	1,590	58,862			0.0370
18	01HABTB023 - OR HABITAT	147	5,689			0.0387
19	01LGSB0030, GEN DEL SRV, > 200		-460,888			
20	01LGSB0030, GEN DEL SRV, > 200		712,202	28		
21	01LGSV0028, OR LRG GEN SRV <		-147,204	1		
22	01LGSV0030 - OR LRG GEN SRV, >		16,072,012	609		
23	01LGSV0048-1000KW AND OVR		7,612,697	88		
24	01LGSV048M-LRG GEN SRVC 1	50,544	1,987,098	1	50,544,000	0.0393
25	01LNX00100-LINE EXT 60% G		9,840			
26	01LNX00102-LINE EXT 80% G		380,116			
27	01LNX00103-LINE EXT 80% G		3,615			
28	01LNX00105-CNTRCT $ MIN G		14,950			
29	01LNX00109-REF/NREF ADV +		1,473,690			
30	01LNX00110-REF/NREF ADV +		12,411			
31	01LNX00120 - Line Extension 60% G		10,837			
32	01LNX00300 - LINE EXT 80%		2,915			
33	01LNX00311 - LINE EXT 80% G		10,800			
34	01LPRS047M-PART REQ SRVC	7,831	545,021	3	2,610,333	0.0696
35	01NMT23135 - OR NET MTR, GEN,		9,102	22		
36	01OALT014N-OUTD AR LGT NR	1,917	242,004	1,249	1,535	0.1262
37	01OALT014N-OUTD AR LGT NR		-17,656			
38	01OALT015N-OUTD AR LGT NR	7,332	778,283	3,237	2,265	0.1061
39	01PTOU0023, OR GEN SRV, TOU	3,748	132,754			0.0354
40	01PTOUB023, OR GEN SRV, TOU	1,505	52,772			0.0351
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
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1	01RCFL0054-REC FIELD LGT	898	75,551	102	8,804	0.0841
2	01RENW0023, OR RENW USAGE	5,029	185,927			0.0370
3	01RENWB023 - OR RENEWABLE	531	20,302			0.0382
4	01STDAY023 - OR DAY STD OFR,	1,660	89,709			0.0540
5	01STDAY028 - OR DAY STD OFF,	3,261	173,273			0.0531
6	01STDAY030 - OR STD DAY OFF,	4,329	234,876			0.0543
7	01ZZMERGCR-MERGER CREDITS		-6			
8	ACQUISITION COMMITMENT-A and		-474,162			
9	ACQUISITION		-362,941			
10	BPA BALANCING ACCOUNT		55,464			
11	01LGSB0048 - LG GEN SVC >		-33,244			
12	01LGSB0048 - LG GEN SVC >		12,375	1		
13	01NMT28135 - OR NET MTR, GEN,		27,709	6		
14	01LGSV028M - OR LGSV, <1000	395	25,310	1	395,000	0.0641
15	01GNSV030M - OR GEN SRV, 200	2,050	99,263	1	2,050,000	0.0484
16	01GNSV0728 - OR GEN SVC DIR		48,769	3		
17	01GNSV0730 -OR GEN SVC DIR		919,863	38		
18	01GNSV0748 LG GEN SVC DIR		37,034	1		
19	OR SB408 RECOVERY		606,074			
20	SMUD REVENUE IMPUTATIONS		885,936			
21	UNBILLED REVENUE	15,717	1,244,000			0.0792
22	UT					
23	08BLSKY01M - BLUE SKY			2		
24	08CFR00051-MTH FAC SRVCHG		65,202			
25	08CFR00052-ANN FAC SVCCHG		2			
26	08CHCK000N-UT NRES CHECK			2		
27	08COOLKPRN - A/C DIRECT LOAD		280	1,866		
28	08GNSV0006-GEN SRVC-DISTR	4,501,299	261,463,158	10,614	424,091	0.0581
29	08GNSV0009-GEN SRVC-HI VO	223,627	8,736,798	18	12,423,722	0.0391
30	08GNSV0023-GEN SRVC-DISTR	1,129,553	78,549,340	60,203	18,762	0.0695
31	08GNSV006A-GEN SRVC-ENERG	175,721	13,507,286	1,539	114,179	0.0769
32	08GNSV006B-GEN SRVC-DEM&	2,480	139,215	10	248,000	0.0561
33	08GNSV006M-MNL DIST VOLTG	4,253	234,453	5	850,600	0.0551
34	08GNSV009A-GEN SRVC HI VO	21,640	924,885	2	10,820,000	0.0427
35	08GNSV009M-MANL HIGH VOLT	25,964	962,437	1	25,964,000	0.0371
36	08GNSV023F-GEN SRVC FIXED	1,383	128,531	116	11,922	0.0929
37	08GNSV023M-GNSV DIST VOLT	235	15,968	8	29,375	0.0679
38	08GNSV06AM-MNL ENERGY TOD	421	46,779	2	210,500	0.1111
39	08GNSV06MN-GNSV DIST VOLT	25,440	1,293,794	372	68,387	0.0509
40	08GNSV09AM-MAN TOD HIVOLT	420	19,194	1	420,000	0.0457
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	08GNSV09LM-GEN TOD LAGOON	1,546	66,771	1	1,546,000	0.0432
2	08LNX00002-MTHLY 80% GUAR		353,032			
3	08LNX00004-ANNUAL 80%GUAR		75,720			
4	08LNX00006-FIXD MTHLY MIN		13,082			
5	08LNX00014-80% MIN MNTHLY		1,460,943			
6	08LNX00017-ADV/REF&80%ANN		61,010			
7	08LNX00150-AGR MTH GUAR M		3,945			
8	08LNX00151-AGR MTH+ADV+BT		-6,736			
9	08LNX00158-ANNUALCOST MTH		33,793			
10	08LNX00300 - LINE EXT 80% PLUS		184,833			
11	08LNX00312 UT IRG LINE EXT		444			
12	08NMT23135 - UT NET MTR, GEN,	18	1,552	3	6,000	0.0862
13	08OALT007N-SECURITY AR LG	9,349	1,790,265	4,882	1,915	0.1915
14	08POLE0075-POLES W/LIGHT		1,246	7		
15	08PRSV031M-BKUP MNT&SUPPL	16,559	855,073	3	5,519,667	0.0516
16	08PTLD000N-POST TOP LIGHT	65	4,868	8	8,125	0.0749
17	08SLC1202F-TRAFFIC SIG NM	219	14,638	32	6,844	0.0668
18	08SLCU1202-TRAF & OTHER S	1,179	84,094	380	3,103	0.0713
19	08SLCU1203-MTR OUTDONIGHT	9,428	661,920	256	36,828	0.0702
20	08ZZMERGCR-MERGER CREDITS		101			
21	ACQUISITION		-437,994			
22	SMUD REVENUE IMPUTATIONS		1,199,407			
23	08LNX00311 - LINE EXT 80%		44,881			
24	08GNSV0008 - UT GEN SVC TOU >	839,026	41,849,775	118	7,110,390	0.0499
25	08GNSV008M - UT GEN SVC TOU >	57,755	3,059,153	6	9,625,833	0.0530
26	UNBILLED REVENUE	31,657	2,081,000			0.0657
27	WA					
28	02GNSB0024-WA GEN SRVC DO	11,257	782,604	3,290	3,422	0.0695
29	02GNSB0024-WA GEN SRVC DO		-113,342			
30	02GNSB024F-GEN SRVC DOM/F	65	5,658	10	6,500	0.0870
31	02GNSB024F-GEN SRVC DOM/F		-96			
32	02GNSB24FP-WA GEN SVC	19	45,462	111	171	2.3927
33	02GNSB24FP-WA GEN SVC		-202			
34	02GNSV0024-WA GEN SRVC	458,489	29,105,254	13,185	34,774	0.0635
35	02GNSV0025-WA GEN SRVC DO	32,367	2,228,779	3,289	9,841	0.0689
36	02GNSV0025-WA GEN SRVC DO		-364,139			
37	02GNSV024F-WA GEN SRVC-FL	1,200	111,714	122	9,836	0.0931
38	02GNSV025F-GEN SRVC DOM/F	192	16,787	10	19,200	0.0874
39	02GNSV025F-GEN SRVC DOM/F		-307			
40	02GNSV24FP-GNSV SEASONAL	234	39,679	113	2,071	0.1696
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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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	02GNSV24FP-GNSV Seasonal		-2,629			
2	02LGSB0036-LRG GEN SVC IRG	26,078	1,305,042	98	266,102	0.0500
3	02LGSB0036-LRG GENSVC IRG		-266,006			
4	02LGSV0035-WA LRG GEN SRV	53,073	2,788,036	96	552,844	0.0525
5	02LGSV0035-WA LRG GEN SRV		-597,070			
6	02LGSV0036-WA LRG GEN SRV	668,945	34,992,635	791	845,695	0.0523
7	02LGSV048T-LRG GEN SRVC 1	153,167	7,215,122	28	5,470,250	0.0471
8	02LNX00102-LINE EXT 80% G		43,622			
9	02LNX00103-LINE EXT 80% G		4,436			
10	02LNX00105-CNTRCT $ MIN G		-7,287			
11	02LNX00109-REF/NREF ADV +		158,344			
12	02LNX00110-REF/NREF ADV +		17,221			
13	02LNX00112-YR INCURRED CH		669			
14	02LNX00300-LINE EXT 80% G		17,266			
15	02OALT013N-WA OUTD AR LGT	501	62,128	594	843	0.1240
16	02OALT013N-WA OUTD AR LGT		-5,658			
17	02OALT015N-WA OUTD AR LGT	1,740	200,406	879	1,980	0.1152
18	02OALTB15N-WA OUTD AR LGT	177	21,887	584	303	0.1237
19	02OALTB15N-WA OUTD AR LGT		-1,808			
20	02RCFL0054-WA REC FIELD L	241	18,534	29	8,310	0.0769
21	02RFNDCENT - CENTRALIA RFND		-140			
22	02ZZMERGCR-MERGER CREDITS		43			
23	02NMT24135, Net metering, WA	5	410	1	5,000	0.0820
24	ACQUISITION COMMITMENT-A and		-130,273			
25	ACQUISITION		-112,051			
26	BPA BALANCING ACCOUNT		60,564			
27	UNBILLED REVENUE	7,357	468,000			0.0636
28	WY					
29	05CHCK000N-WY NRES CHECK			1		
30	05GNSV0025-WY GEN SRVC	1,017,759	66,446,025	20,094	50,650	0.0653
31	05GNSV025F-GEN SRVC-FL RA	1,098	121,886	195	5,631	0.1110
32	05LGSV046M-WY LRG GEN SRV	2,208	90,358	1	2,208,000	0.0409
33	05LGSV046T-LRG GEN SERV	209,610	9,748,480	19	11,032,105	0.0465
34	05LNX00100-LINE EXT 60% G		239			
35	05LNX00102-LINE EXT 80% G		431,630			
36	05LNX00105-CNTRCT $ MIN G		5,369			
37	05LNX00109-REF/NREF ADV +		365,461			
38	05LNX00110-REF/NREF ADV +		280			
39	05LNX00114-TEMP SVC 12MO>		-4,541			
40	05NMT25135 - WY NET MTR, GEN,	363	31,709	2	181,500	0.0874
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	05OALT015N-OUTD AR LGT SR	3,483	457,526	1,856	1,877	0.1314
2	05RCFL0054-WY REC FIELD L	683	52,003	54	12,648	0.0761
3	05RFNDCENT-CENTRALIA RFND		6			
4	09GNSV0025-GEN SVC-SINGLE	1	214	1	1,000	0.2140
5	09GNSV0206-GEN SRVC-SINGL		42	1		
6	05LNX00300 - LINE EXT 80%		275,366			
7	05LNX00311 - LINE EXT 80%		6,782			
8	ACQUISITION COMMITMENT-A and		-96,863			
9	ACQUISITION		-92,068			
10	SMUD REVENUE IMPUTATIONS		148,091			
11	UNBILLED REVENUE	-322	434,000			-1.3478
12	05GNSV0025-WY GEN SRVC	1,317	104,088	63	20,905	0.0790
13	05GNSV025F-GEN SRVC-FL RA	121	11,740	31	3,903	0.0970
14	05LNX00102-LINE EXT 80% G		776			
15	05LNX00103-LINE EXT 80% G		610			
16	05LNX00109-REF/NREF ADV +		62,808			
17	05LNX00110-REF/NREF ADV +		3,852			
18	09GNSV0025-GEN SVC-SINGLE	101,969	6,663,782	2,293	44,470	0.0654
19	09GNSV0206-GEN SRVC-SINGL	22,773	1,384,209	2,276	10,006	0.0608
20	09GNSV025F-GEN SVC-FIXED	107	8,808	14	7,643	0.0823
21	09GNSV025M-GEN SVC-MANUAL	2,003	126,040	3	667,667	0.0629
22	09GNSV206F-GEN SRVC-FIXED	42	4,070	39	1,077	0.0969
23	09GNSV206M-GENSERV MANUAL	456	26,557	3	152,000	0.0582
24	09OALT207N-SECURITY AR LG	298	92,784	146	2,041	0.3114
25	09SLCU2123-MTR OUTDONIGHT	47	3,365	2	23,500	0.0716
26	05LNX00300 - LINE EXT 80%		2,984			
27	05LNX00311 - LINE EXT 80%		265			
28	SMUD REVENUE IMPUTATIONS		27,868			
29	UNBILLED REVENUE	3,040	213,000			0.0701
30	Less Multiple Billings			-31,104		
31						
32	COMMERCIAL SALES TOTAL	15,397,126	917,467,966	199,474	77,189	0.0596
33						
34	INDUSTRIAL SALES					
35	CA					
36	06GNSV0025-CA GEN SRVC	940	103,400	104	9,038	0.1100
37	06GNSV0A32-GEN SRVC-20 KW	1,805	194,099	22	82,045	0.1075
38	06LGSV048T-LRG GEN SERV	50,607	2,703,501	4	12,651,750	0.0534
39	06LGSV0A36-LRG GEN SRVC-O	9,195	717,944	16	574,688	0.0781
40	06LNX00109-REF/NREF ADV +		1,603			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	ACQUISITION COMMITMENT-A and		-10,095			
2	ACQUISITION		-6,114			
3	CA ALT RATE FOR ENERGY		87,027			
4	SMUD REVENUE IMPUTATIONS		13,524			
5	UNBILLED REVENUE	-323	-19,000			0.0588
6	ID					
7	07CFR00001-MTH FACILITY S		2,145			
8	07CISH0019-COMM & IND SPA	167	12,716	7	23,857	0.0761
9	07GNSV0006-GEN SRVC-LRG P	87,272	4,593,576	111	786,234	0.0526
10	07GNSV0008-GEN SRVC-MEDIU	2,433	134,135	2	1,216,500	0.0551
11	07GNSV0009-GEN SRVC-HI VO	88,103	3,895,575	11	8,009,364	0.0442
12	07GNSV0023-GEN SRVC-SML P	11,464	885,400	356	32,202	0.0772
13	07GNSV006A-GEN SRVC-LRG P	5,723	367,669	38	150,605	0.0642
14	07GNSV006A-GEN SRVC-LRG P		-109,977			
15	07GNSV023A-GEN SRVC-SML P	2,368	219,871	267	8,869	0.0929
16	07GNSV023A-GEN SRVC-SML P		-45,502			
17	07LNX00035-ADV 80%MO GUAR		1,567			
18	07LNX00108-ANN COST MTHLY		1,996			
19	07OALT007N-SECURITY AR LG	16	3,421	19	842	0.2138
20	07OALT07AN-SECURITY AR LG	1	333	2	500	0.3330
21	07OALT07AN-SECURITY AR LG		-25			
22	07SLCU1201-TRAF SIGNAL SY	8	935	3	2,667	0.1169
23	07SPCL0001	1,357,700	41,324,896	1	1,357,700,000	0.0304
24	07SPCL0002	119,309	4,200,978	1	119,309,000	0.0352
25	ACQUISITION COMMITMENT-A and		-164,045			
26	ACQUISITION		-156,764			
27	BPA BALANCING ACCOUNT		-53,529			
28	UNBILLED REVENUE	-15,432	-254,000			0.0165
29	OR					
30	01COST0023, OR GEN SRV, COST	22,902	828,527			0.0362
31	01COST0048 - 01LGSV0048	1,744,412	57,717,910			0.0331
32	01COST023F - OR GEN SRV -	3	135			0.0450
33	01COSTB023 - OR GEN SRV,	375	13,994			0.0373
34	01COSTL028, OR LRG SRV, COST	-134	-4,544			0.0339
35	01COSTL030 - OR LRG GEN SRV,	280,248	9,834,982			0.0351
36	01COSTS028, OR GEN SERV,	119,893	4,189,381			0.0349
37	01GNSB0023 - BPA DISC, < 30 kW		-3,770			
38	01GNSB0023, OR GEN SRV, BPA, <		24,820	69		
39	01GNSB0028 - OR GEN SRVC,		-4,911			
40	01GNSB0028, OR GEN SRV, BPA, >		16,591	6		
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	01GNSV0023, OR GEN SRV, < 30		878,260	1,180		
2	01GNSV0028, OR GEN SRV > 30		3,296,817	564		
3	01GNSV023F - OR GEN SRV - FLAT		645	3		
4	01GNSV023M - OR GEN SRV,	3	849	1	3,000	0.2830
5	01GNSV023T, OR GEN SRV, TOU		3,868	4		
6	01HABT0023, OR HABITAT	97	3,317			0.0342
7	01LGSB0030, GEN DEL SRV, > 200		-33,094			
8	01LGSB0030, GEN DEL SRV, > 200		55,395	1		
9	01LGSV0028, OR LRG GEN SRV <		-3,155			
10	01LGSV0030 - OR LRG GEN SRV, >		5,878,292	193		
11	01LGSV0048-1000KW AND OVR		15,684,615	120		
12	01LGSV048M-LRG GEN SRVC 1	584,281	21,724,445	5	116,856,200	0.0372
13	01LNX00105-CNTRCT $ MIN G		3,090			
14	01LNX00109-REF/NREF ADV +		18,705			
15	01LNX00300 - LINE EXT 80%		7,478			
16	01LPRS047M-PART REQ SRVC	492,488	18,276,273	4	123,122,000	0.0371
17	01NMT28135 - OR NET MTR, GEN,		1,290	1		
18	01OALT014N-OUTD AR LGT NR	9	1,177	9	1,000	0.1308
19	01OALT014N-OUTD AR LGT NR		-84			
20	01OALT015N-OUTD AR LGT NR	466	46,841	164	2,841	0.1005
21	001PTOU0023, OR GEN SRV, TOU	88	3,199			0.0364
22	01RENW0023, OR RENW USAGE	184	6,838			0.0372
23	01RENWB023 - OR RENEWABLE	1	29			0.0290
24	01ZZMERGCR-MERGER CREDITS		23			
25	ACQUISITION COMMITMENT-A and		-304,575			
26	ACQUISITION		-233,132			
27	BPA BALANCING ACCOUNT		47			
28	01STDAY023 - OR DAY STD OFR,	34	1,807			0.0531
29	01LGSV028M - OR LGSV, <1000	109	9,489	1	109,000	0.0871
30	OR SB408 RECOVERY		15,963			
31	SMUD REVENUE IMPUTATIONS		562,184			
32	UNBILLED REVENUE	-7,776	-368,000			0.0473
33	UT					
34	08CFR00051-MTH FAC SRVCHG		16,329			
35	08EFOP0021-ELEC FURNACE O	1,427	87,840	2	713,500	0.0616
36	08EFOP021M-ELEC FURNACE O	2,075	208,738	3	691,667	0.1006
37	08GNSV0006-GEN SRVC-DISTR	767,828	47,078,876	1,351	568,340	0.0613
38	08GNSV0009-GEN SRVC-HI VO	2,372,252	86,022,843	109	21,763,780	0.0363
39	08GNSV0023-GEN SRVC-DISTR	61,247	4,340,442	3,884	15,769	0.0709
40	08GNSV006A-GEN SRVC-ENERG	58,066	4,721,381	229	253,563	0.0813
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	08GNSV006B-GEN SRVC-DEM&	3,070	220,945	6	511,667	0.0720
2	08GNSV006M-MNL DIST VOLTG	1,364	77,142	1	1,364,000	0.0566
3	08GNSV009A-GEN SRVC HI VO	17,543	923,660	6	2,923,833	0.0527
4	08GNSV009M-MANL HIGH VOLT	691,420	24,266,072	11	62,856,364	0.0351
5	08GNSV023F-GEN SRVC FIXED	4	1,316	2	2,000	0.3290
6	08GNSV06MN-GNSV DIST VOLT	952	49,657	17	56,000	0.0522
7	08GNSV09AM-MAN TOD HIVOLT	1,245	107,947	1	1,245,000	0.0867
8	08LNX00002-MTHLY 80% GUAR		4,899			
9	08LNX00004-ANNUAL 80%GUAR		757			
10	08LNX00014-80% MIN MNTHLY		67,031			
11	08LNX00017-ADV/REF&80%ANN		6,233			
12	08LNX00150-AGR MTH GUAR M		1,728			
13	08LNX00300 - LINE EXT 80% PLUS		1,094			
14	08OALT007N-SECURITY AR LG	1,544	272,802	555	2,782	0.1767
15	08PRSV031M-BKUP MNT&SUPPL	112	5,598	1	112,000	0.0500
16	08SLCU1202-TRAF & OTHER S	44	2,851	8	5,500	0.0648
17	08SLCU1203-MTR OUTDONIGHT	11	2,775	6	1,833	0.2523
18	08SPCL0001	589,057	17,835,146	1	589,057,000	0.0303
19	08SPCL0002	767,211	21,183,374	1	767,211,000	0.0276
20	08SPCL0003	654,937	21,405,451	1	654,937,000	0.0327
21	08SPCL0005	224,635	7,664,316	1	224,635,000	0.0341
22	08SPCL0011	20,342	1,432,698	1	20,342,000	0.0704
23	08ZZMERGCR-MERGER CREDITS		-1			
24	ACQUISITION		-448,687			
25	SMUD REVENUE IMPUTATIONS		1,244,511			
26	08GNSV06AM-MNL ENERGY TOD	91	8,653	1	91,000	0.0951
27	08GNSV0008 - UT GEN SVC TOU >	968,189	49,621,388	108	8,964,713	0.0513
28	08GNSV008M - UT GEN SVC TOU >	69,750	3,551,180	8	8,718,750	0.0509
29	UNBILLED REVENUE	37,578	1,394,000			0.0371
30	WA					
31	02GNSB0024-WA GEN SRVC DO	841	56,256	114	7,377	0.0669
32	02GNSB0024-WA GEN SRVC DO		-8,751			
33	02GNSB24FP-WA GEN SVC		614	1		
34	02GNSB24FP-WA GEN SVC		-1			
35	02GNSV0024-WA GEN SRVC	19,097	1,219,613	381	50,123	0.0639
36	02GNSV0025-WA GEN SRVC DO	1,890	133,122	117	16,154	0.0704
37	02GNSV0025-WA GEN SRVC DO		-21,267			
38	02GNSV024F-WA GEN SRVC-FL	33	5,441	4	8,250	0.1649
39	02GNSV24FP-GNSV SEASONAL	1	623	1	1,000	0.6230
40	02GNSV24FP-GNSV Seasonal		-9			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

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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	02LGSV0035-WA LRG GEN SRV	2,214	206,527	27	82,000	0.0933
2	02LGSV0035-WA LRG GEN SRV		-24,902			
3	02LGSV0036-WA LRG GEN SRV	145,564	7,741,178	133	1,094,466	0.0532
4	02LGSV048M-WA LRG GEN SRV	72,852	3,301,774	1	72,852,000	0.0453
5	02LGSV048T-LRG GEN SRVC 1	710,265	29,878,654	35	20,293,286	0.0421
6	02LNX00102-LINE EXT 80% G		1,572			
7	02LNX00109-REF/NREF ADV +		800			
8	02OALT013N-WA OUTD AR LGT	24	3,031	20	1,200	0.1263
9	02OALT013N-WA OUTD AR LGT		-275			
10	02OALT015N-WA OUTD AR LGT	120	13,249	44	2,727	0.1104
11	02OALTB15N-WA OUTD AR LGT	8	1,040	19	421	0.1300
12	02OALTB15N-WA OUTD AR LGT		-86			
13	02PRSV47TM-LRG PART REQMT	21,107	1,959,919	2	10,553,500	0.0929
14	02RFNDCENT - CENTRALIA RFND		38			
15	02ZZMERGCR-MERGER CREDITS		10			
16	02LGSB0036-LRG GEN SVC IRG	1,698	117,282	29	58,552	0.0691
17	02LGSB0036-LRG GENSVC IRG		-18,720			
18	02LGSB048T - WA GEN SRVC, BPA		-29,804			
19	02LGSB048T - WA GEN SRVC, NO	2,896	139,107	1	2,896,000	0.0480
20	ACQUISITION COMMITMENT-A and		-97,205			
21	ACQUISITION		-83,608			
22	BPA BALANCING ACCOUNT		4,267			
23	UNBILLED REVENUE	11,567	484,000			0.0418
24	WY					
25	05GNSV0025-WY GEN SRVC	291,300	16,624,168	1,670	174,431	0.0571
26	05GNSV025F-GEN SRVC-FL RA	83	8,344	16	5,188	0.1005
27	05GNSV025M - General Service	1,659	104,029	2	829,500	0.0627
28	05LGS45025-LRG GEN SRVC	-1,149	-70,408			0.0613
29	05LGSV046M-WY LRG GEN SRV	578,058	24,128,614	5	115,611,600	0.0417
30	05LGSV046T-LRG GEN SERV	1,282,552	56,146,414	58	22,112,966	0.0438
31	05LGSV048M-TOU>1000KW MAN	1,127,170	37,638,246	3	375,723,333	0.0334
32	05LGSV048T-LRG GENSRV TIM	766,163	26,043,840	7	109,451,857	0.0340
33	05LNX00100-LINE EXT 60% G		13,176			
34	05LNX00102-LINE EXT 80% G		138,359			
35	05LNX00105-CNTRCT $ MIN G		48,357			
36	05LNX00109-REF/NREF ADV +		248,676			
37	05OALT015N-OUTD AR LGT SR	100	11,910	46	2,174	0.1191
38	05PRSV033M-PART SERV REQ	1,055,188	42,037,495	5	211,037,600	0.0398
39	ACQUISITION COMMITMENT-A and		-432,964			
40	ACQUISITION		-411,530			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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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	SMUD REVENUE IMPUTATIONS		902,270			
2	05LNX00300 - LINE EXT 80%		11,384			
3	UNBILLED REVENUE	43,663	2,449,000			0.0561
4	05GNSV0025-WY GEN SRVC	1,033	65,876	22	46,955	0.0638
5	05GNSV025M - General Service	2	184	1	2,000	0.0920
6	05LGSV046M-WY LRG GEN SRV	4,021	210,213	1	4,021,000	0.0523
7	05LGSV046T-LRG GEN SERV	8,444	360,070	1	8,444,000	0.0426
8	05LGSV048M-TOU>1000KW MAN	290,657	10,117,380	6	48,442,833	0.0348
9	05LGSV048T-LRG GENSRV TIM	249,179	8,821,161	6	41,529,833	0.0354
10	05LNX00109-REF/NREF ADV +		3,075			
11	05PRSV033M-PART SERV REQ	340	167,416	1	340,000	0.4924
12	09GNSV0025-GEN SVC-SINGLE	36,367	2,216,903	374	97,238	0.0610
13	09GNSV0206-GEN SRVC-SINGL	7,919	469,120	392	20,202	0.0592
14	09GNSV0217-LRG POWER SRVC	87,540	3,033,013	5	17,508,000	0.0346
15	09GNSV025M-GEN SVC-MANUAL	3,894	193,724	3	1,298,000	0.0497
16	09GNSV206M-GENSERV MANUAL	932	44,020	4	233,000	0.0472
17	09GNSV217M-LRG POWER SRVC	95,916	3,281,938	6	15,986,000	0.0342
18	09OALT207N-SECURITY AR LG	7	1,921	4	1,750	0.2744
19	09PRSV033M	1,269	193,520	1	1,269,000	0.1525
20	09PRSV218M-BKUP,MNT,SUPPL	119	74,390	2	59,500	0.6251
21	SMUD REVENUE IMPUTATIONS		137,663			
22	UNBILLED REVENUE	6,469	406,000			0.0628
23	Less Multiple Billings			-1,681		
24						
25	INDUSTRIALSALES TOTAL	19,200,105	770,600,712	11,492	1,670,737	0.0401
26						
27	IRRIGATION SALES					
28	CA					
29	06APSV0020-AG PMP SRVC	60,021	4,771,069	1,306	45,958	0.0795
30	06LNX00102-LINE EXT 80% G		404			
31	06LNX00103-LINE EXT 80% G		124			
32	06LNX00110-REF/NREF ADV +		11,491			
33	06SLX00001-KLAM FALLS MIN		729			
34	06UKRB0035-KLAM OFF PROJ			2		
35	06USBR0040-KLAM IRG ONPRJ	30,570	1,719,365	659	46,388	0.0562
36	06USBR033T USBR	6,069	22,989	43	141,140	0.0038
37	06LNX00109-REF/NREF ADV +		-1,663			
38	IRRIGATION UNBILLED	-240				
39	ID					
40	07APSA010L - IRG & Pump BPA		-16,893,211			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	07APSA010L - IRG & Pump Large	535,348	33,946,924	3,479	153,880	0.0634
2	07APSA010S - IRG & Pump BPA		-165,147			
3	07APSA010S - IRG & Pump Small	5,235	403,138	390	13,423	0.0770
4	07APSAL10X - IRG & PUMP - Large I	36,408	2,452,764	511	71,249	0.0674
5	07APSAS10X - IRG & PUMP - Small	1,157	108,616	214	5,407	0.0939
6	07APSC010L - IRG PUMP Srv BPA		2,835			
7	07APSC010L - IRG PUMP Srv Large	-71	-6,721			0.0947
8	07APSC010S - IRG PUMP SRV		-19			
9	07APSCL10X - was 07APSC10LX	-522	-39,319			0.0753
10	07APSCS10X - was 07APSC10SX	-9	-1,965			0.2183
11	07APSVCNLL-LRG LOAD	14,899	861,502	48	310,396	0.0578
12	07APSVCNLL-LRG LOAD CANAL		-447,737			
13	07APSVCNLS-SML LOAD CANAL	50	4,440	9	5,556	0.0888
14	07APSVCNLS-SML LOAD CANAL		-1,318			
15	07BPADEBIT-BPA ADJUST FEE		2,680,253			
16	07LNX00015-ANNUAL 80%GUAR		9,634			
17	07LNX00040-ADV+REFCHG+80%		153,885			
18	07LNX00107-SUBD ADV & AIC		1,097			
19	07LNX00310 80% ANNUAL		3,398			
20	07LNX00312 - ID LINE EXT		4,615			
21	07APSN010L - ID LG IRR & PUMP	1,404	103,772	16	87,750	0.0739
22	07APSN010L - ID LG, IRR, 3 PH, BP		-44,294			
23	07APSN010S - IRR, SMALL, 3 PH,		-4,665			
24	07APSN010S - IRRIGATION,	148	11,299	7	21,143	0.0763
25	07APSNS10X - IRRIGATION,	31	2,762	2	15,500	0.0891
26	IRRIGATION BPA BAL ACCT		3,215,940			
27	UNBILLED REV - IRRIGATION	-2,195	-213,000			0.0970
28	OR					
29	01APSV0041-AG PMP SRVC BP		1,833,049	4,796		
30	01APSV0041-AG PMP SRVC BP		-478,545			
31	01APSV041L-OR Pumping Serv		2,496,434	1,003		
32	01APSV041L-OR Pumping Serv BPA		-755,719			
33	01APSV041T - AGR PUMP SRV		-6,426			
34	01APSV041T - AGR PUMP		26,791	63		
35	01APSV041X-AG PMP SRVC		74,667	222		
36	01APSV41XL-OR Pumping Serv no		119,323	43		
37	01BPADEBIT-BPA ADJUST FEE		43,927			
38	01COST0041	124,422	4,474,936			0.0360
39	01COSTS028, OR GEN SERV,	254	8,948			0.0352
40	01GNSV0028, OR GEN SRV > 30		8,591	2		
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	01LGSV0030-3P,DEMAND,VAR,SEC		-24			
2	01LNX00102-LINE EXT 80% G		163			
3	01LNX00103-LINE EXT 80% G		18,168			
4	01LNX00109-REF/NREF ADV +		372			
5	01LNX00110-REF/NREF ADV +		105,328			
6	01NMT41135 - NETMTR AG PMP		63	1		
7	01PTOU0041 - 01APSV0041 AG	629	19,211			0.0305
8	01RENEW041 - 01APSV0041 AG	93	3,347			0.0360
9	01SLX00005-KLAMATH FALLS		207,475			
10	01SLX00013-K FALLS IRG MI		14,686			
11	01SLX00014-K FALLS IRG MI		2,624			
12	01STDAY041 - Daily Standard Offer	5	111			0.0222
13	01UKRB0035-KLAMATH BASIN	48,932	484,149	679	72,065	0.0099
14	01UKRB0035-KLAMATH BASIN		-276,747			
15	01USBR0040-KLAMATH BASIN	57,416	466,649	1,403	40,924	0.0081
16	01USBR0040-KLAMATH BASIN		-536,346			
17	01USBR33TX-IR TOU W/O BPA	5,327	23,202	10	532,700	0.0044
18	01ZZMERGCR-MERGER CREDITS		-6			
19	IRRIGATION BPA BAL ACCT		-97,601			
20	IRRIGATION UNBILLED	87	22,000			0.2529
21	OR ENRGY COST RECOV AMORT		-944,606			
22	OR Irrigation - BPA adjustment		18,135			
23	01LNX00310-LINE EXTENSION		222			
24	01LNX00312 - OR IRG LINE EXT		1,905			
25	OR SB408 RECOVERY		65,973			
26	UT					
27	08APSV0010-IRR & SOIL DRA	158,827	8,084,591	2,405	66,040	0.0509
28	08APSV10NS- Irg Soil Drain Pump N	12,142	602,022	67	181,224	0.0496
29	08LNX00002-MTHLY 80% GUAR		852			
30	08LNX00004-ANNUAL 80%GUAR		68,433			
31	08LNX00014-80% MIN MNTHLY		6,526			
32	08LNX00017-ADV/REF&80%ANN		104,243			
33	08LNX00152-AGR ANN GUAR M		1,105			
34	08LNX00153-AGR ANN+ADV+BT		970			
35	08LNX00310 - IRR, 80% ANNUAL		3,440			
36	08LNX00312 UT IRG LINE EXT		2,886			
37	08NMT10135-UT IRR_SOIL DRNG	6	347	1	6,000	0.0578
38	UNBILLED REV - IRRIGATION	-25	2,000			-0.0800
39	WA					
40	02APSV0040-WA AG PMP SRVC	136,211	8,050,954	4,663	29,211	0.0591
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

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1	02APSV0040-WA AG PMP SRVC		-1,527,858			
2	02APSV040X-WA AG PMP SRVC	18,104	1,067,940	575	31,485	0.0590
3	02BPADEBIT-BPA ADJUST FEE		46,050			
4	02LNX00102-LINE EXT 80% G		1,086			
5	02LNX00103-LINE EXT 80% G		7,012			
6	02LNX00105-CNTRCT $ MIN G		30			
7	02LNX00109-REF/NREF ADV +		1,835			
8	02LNX00110-REF/NREF ADV +		50,756			
9	02RFNDCENT - CENTRALIA RFND		-113			
10	02ZZMERGCR-MERGER CREDITS		-29			
11	IRRIGATION BPA BAL ACCT		-24,338			
12	IRRIGATION UNBILLED	187	42,000			0.2246
13	WY					
14	05APS00040-AG PUMPING SVC	17,992	1,308,343	553	32,535	0.0727
15	05LNX00110-REF/NREF ADV +		37,126			
16	05LNX00103-LINE EXT 80% G		1,603			
17	05LNX00105-CNTRCT $ MIN G		31			
18	05LNX00310-LINE EXTENSION		121			
19	IRRIGATION UNBILLED	-77	-8,000			0.1039
20	05APS00040-AG PUMPING SVC	12	855	1	12,000	0.0713
21	05LNX00103-LINE EXT 80% G		5,019			
22	05LNX00110-REF/NREF ADV +		3,339			
23	09APSV0210-IRR & SOIL DRA	2,592	162,958	42	61,714	0.0629
24	Less Multiple Billings			-608		
25						
26	IRRIGATION SALES TOTAL	1,271,439	58,222,550	22,607	56,241	0.0458
27						
28	PUBLIC STREET&HIGHWAY LIGHT					
29	CA					
30	06COSL0052-CO-OWND STR LG	8	5,667	5	1,600	0.7084
31	06CUSL053F-SPECIAL CUST O	1,424	136,943	123	11,577	0.0962
32	06CUSL058F-CUST OWND STR	243	27,341	25	9,720	0.1125
33	06HPSV0051-HI PRESSURE SO	711	145,797	76	9,355	0.2051
34	UNBILLED REVENUE	-41	-5,000			0.1220
35	ID					
36	07SLCO0011-STR LGT CO-OWN	131	30,506	31	4,226	0.2329
37	07SLCU1201-TRAF SIGNAL SY	182	15,620	25	7,280	0.0858
38	07SLCU1203-STR LGT CUST-O		293	1		
39	07SLCU122A-STR LGT CUST-O	181	9,581	14	12,929	0.0529
40	07SLCU122B-STR LGT CUST-O	1,824	195,537	258	7,070	0.1072
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	UNBILLED REVENUE	3				
2	OR					
3	01COSL0052-STR LGT SRVC C	1,980	211,836	101	19,604	0.1070
4	01CUSL0053-CUS-OWNED MTRD	692	44,403	52	13,308	0.0642
5	01CUSL053E-STR LGT SVC		28	5		
6	01CUSL053F-STR LGT SRVC C	9,357	501,643	175	53,469	0.0536
7	01HPSV0051-HI PRESSURE SO	17,283	2,753,505	668	25,873	0.1593
8	01MVSL0050-MERC VAPSTR LG	11,784	1,235,926	315	37,410	0.1049
9	01OALT014N-OUTD AR LGT NR		67	1		
10	01OALT014N-OUTD AR LGT NR		-2			
11	01OALT015N-OUTD AR LGT NR	3	440	2	1,500	0.1467
12	OR SB408 RECOVERY		4,832			
13	UNBILLED REVENUE	-48	75,000			-1.5625
14	UT					
15	08CFR00012-STR LGTS (CONV		58			
16	08CFR00051-MTH FAC SRVCHG.		4,529			
17	08CFR00061-U/G AREA LIGHT		127			
18	08CFR00062-STREET LIGHTS		79			
19	08HAXT0060-LIGHTNG-HAXTON		93	1		
20	08OALT007N-SECURITY AR LG	17	2,994	5	3,400	0.1761
21	08SLC1202F-TRAFFIC SIG NM	1,211	75,422	130	9,315	0.0623
22	08SLCO0011-STR LGT CO-OWN	24,086	5,613,141	1,156	20,836	0.2330
23	08SLCU1202-TRAF & OTHER S	3,749	280,368	1,536	2,441	0.0748
24	08SLCU1203-MTR OUTDONIGHT	1,002	72,516	45	22,267	0.0724
25	08SLCU121A-STR LGT CUST-O	13,019	1,087,435	359	36,265	0.0835
26	08SLCU121B-STR LGT CUST-O	9,195	856,466	206	44,636	0.0931
27	08SLD13ES1-DECOR CUST-OWN	5,744	289,552	48	119,667	0.0504
28	08SLD13ES2-DECOR CUST-OWN	17,736	896,147	50	354,720	0.0505
29	08SLD13FS1-DECOR COMP-OWN	65	34,252	4	16,250	0.5270
30	08SLD13FS2-DECOR COMP-OWN	206	113,242	13	15,846	0.5497
31	08SLD13MS1-DECOR CUST-OWN	527	65,193	13	40,538	0.1237
32	08SLD13MS2-DECOR CUST-OWN	991	123,374	19	52,158	0.1245
33	08THIK0077-STR LIGHT SPEC	141	17,277	1	141,000	0.1225
34	UNBILLED REVENUE	3,310	437,000			0.1320
35	WA					
36	02CFR00012-STR LGTS (CONV		91			
37	02COSL0052-WA STR LGT SRV	458	55,757	26	17,615	0.1217
38	02CUSL053F-WA STR LGT SRV	3,420	204,416	183	18,689	0.0598
39	02CUSL053M-WA STR LGT SRV	966	57,090	84	11,500	0.0591
40	02HPSV0051-WA HI PRESSURE	2,815	479,328	160	17,594	0.1703
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	Year/Period of Report 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	RENT REV-GEN(COMM)		42,525			
2	Rent Revenue - Subleases		42,171			
3	Joint use		558,630			
4	09LOOP0214-MTH FEE PRE-AS		229			
5	09POLE0075-STEEL POLES US		23,713			
6	RENT REVENUE-STEAM		5,338			
7	Joint use		-167,059			
8						
9	Total RENT FROM ELEC		19,392,877			
10						
11	MISCELLANEOUS SERVICE REV					
12	WY					
13	ALL BLUE SKY RES		11,122			
14	ALL NON-RES BLUE SKY		394			
15	ALL BLUE SKY RES		89,693			
16	ALL NON-RES BLUE SKY		8,086			
17	WA					
18	ALL BLUE SKY RES		79,676			
19	ALL NON-RES BLUE SKY		16,594			
20	UT					
21	ALL BLUE SKY RES		856,434			
22	ALL NON-RES BLUE SKY		221,314			
23	OR					
24	01XTRNBSKY - Blue Sky		6,322			
25	ALL BLUE SKY RES		256,390			
26	ALL NON-RES BLUE SKY		358,536			
27	ID					
28	ALL BLUE SKY RES		29,778			
29	ALL NON-RES BLUE SKY		1,650			
30	CA					
31	ALL BLUE SKY RES		34,273			
32	ALL NON-RES BLUE SKY		1,018			
33	WHEELING ESTIMATE		24,307			
34	OTH ELEC ESTIMATE		-215,075			
35	GREEN CREDIT SALES		1,011,684			
36	NON-WHEELING SYSTEM		7,875,451			
37	Other Elec (exclud Wheel)		12,539,580			
38	Post Merg Firm Wheeling		2,478,498			
39	OTH ELEC REV - TRANS ANC		354,735			
40	Inter-Co Other Elec Revenues		88,317			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
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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	CA					
2	Fish, Wildlife, Recr		4,546			
3	ID					
4	DSM REV-ID SBC		1,374,343			
5	Other Elec (exclud Wheel)		224			
6	OR					
7	01CFR00001-MTH FACILITY S		41,490			
8	01CFR00004-EMRGNCY ST&BY		15,660			
9	01CFR00005-INTERMTNT SRVC		29,874			
10	ELEC INC-OTHR		148			
11	3RD PARTY TRANS		494,314			
12	INTERCO FIRM WHEEL		899,737			
13	Non-Firm Wheeling		1,122,478			
14	Other Elec (exclud Wheel)		4,593,944			
15	Other Elec DSR carry chrg		461,865			
16	Post Merg Firm Wheeling		432,013			
17	Pre Merg Firm Wheel PPL		1,163,777			
18	Pre Merg Firm Wheel UPL		3,668,802			
19	Short-term Firm Wheeling		200,736			
20	Inter-Co Other Elec Revenues		31,030			
21	INTERCO Short-Term WHEEL		471,992			
22	UT					
23	08CFR00053-MTHLY MAINTFEE		6,241			
24	08XTRN0016-OUTBIL SVC REN		152,808			
25	ELEC INC-OTHR		321,515			
26	FLYASH SALES		348,302			
27	DSM REV-UT SBC OFFSET		29,115,718			
28	Fish, Wildlife, Recr		1,995			
29	Other Elec (exclud Wheel)		-863,124			
30	WA					
31	02CFR00004-EMRGNCY ST&BY		3,943			
32	02CFR00005-INTERMTNT SRVC		2,924			
33	Fish, Wildlife, Recr		4,306			
34	Other Elec (exclud Wheel)		-422,363			
35	Wash Colstrip 3		-52,188			
36	WY					
37	05CFR00004-EMRGNCY ST&BY		14,084			
38	05CFR00005-INTERMTNT SRVC		7,163			
39	09CFR00005-INTERMTNT SRVC		226			
40	ELEC INC-OTHR		355			
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	End of 2006/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	FLYASH SALES		1,507,145			
2	WY Regulatory Recovery Fee		172,202			
3	FLYASH SALES		8,753			
4						
5	OTHER ELECTRIC REVENUE		71,465,755			
6						
7	OTHER ELECTRIC REVENUE					
8	WHEELING ESTIMATE		-826,170			
9	OTH ELEC REV - TRANS ANC		1,820,738			
10	OR					
11	ANCILLARY SERVICES REVENUE		1,071,318			
12	Non-Firm Wheeling		9,139,748			
13	Post Merg Firm Wheeling		8,100,160			
14	Pre Merg Firm Wheel PPL		3,611,571			
15	Pre Merg Firm Wheel UPL		11,673,914			
16	Short-term Firm Wheeling		4,629,915			
17	USE OF FACILITY-REVENUE		2,025,300			
18						
19	Total Revenues from Transmission		41,246,494			
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	51,688,357	2,983,333,391	0	0	0.0577
42	Total Unbilled Rev.(See Instr. 6)	108,980	7,994,000	0	0	0.0734
43	TOTAL	51,797,337	2,991,327,391	0	0	0.0578

Schedule Page: 304 Line No.: 42 Column: c

For a further discussion on unbilled revenue refer to page 300, *Electric Operating Revenues*, line 12 column (b).

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(Next Page is: 310)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Brigham City	RQ	T-6	19	18	17
2	Deaver, Town of	RQ	T-4	0.2	0.1	0.1
3	Helper City	RQ	T-6	1	1	0.9
4	Helper City Annex	RQ	T-6	0.7	0.6	0.6
5	Navajo Tribal Utility Authority -	RQ	T-6	0.2	0.2	0.2
6	(Mexican Hat)					
7	Navajo Tribal Utility Authority -	RQ	T-6	1	1	1
8	(Red Mesa)					
9	Portland General Electric Co.	RQ	147	NA	NA	NA
10	Price City	RQ	T-6	12	12	11
11	Accrual True-up	RQ	NA	NA	NA	NA
12	American Electric Power	SF	WSPP	NA	NA	NA
13	Anaheim, City of	SF	WSPP	NA	NA	NA
14	Arizona Public Service Co.	IF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
110,660	1,754,614	1,927,702		3,682,316	1
1,028	14,768	18,535		33,303	2
6,132	110,354	108,559		218,913	3
3,786	71,976	67,025		139,001	4
1,139	21,500	19,840		41,340	5
					6
6,960	110,419	121,155	2,190	233,764	7
					8
11,048		921,365		921,365	9
75,365	1,158,002	1,313,689		2,471,691	10
-90			-2,805	-2,805	11
279,800		13,410,074	22,900	13,432,974	12
360		16,615		16,615	13
96,600		3,835,020		3,835,020	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Arizona Public Service Co.	OS	T-12	NA	NA	NA
2	Arizona Public Service Co.	SF	T-12	NA	NA	NA
3	Avista Corp.	OS	WSPP	NA	NA	NA
4	Avista Corp.	SF	T-11	NA	NA	NA
5	Avista Corp.	SF	T-13	NA	NA	NA
6	Avista Corp.	SF	WSPP	NA	NA	NA
7	Avista Energy, Inc.	OS	WSPP	NA	NA	NA
8	Avista Energy, Inc.	SF	T-11	NA	NA	NA
9	Avista Energy, Inc.	SF	WSPP	NA	NA	NA
10	BP Energy Company	SF	WSPP	NA	NA	NA
11	Barclays Bank PLC	SF	T-12	NA	NA	NA
12	Basin Electric Power Cooperative	LF	T-11	NA	NA	NA
13	Basin Electric Power Cooperative	OS	WSPP	NA	NA	NA
14	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
	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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
26,118		1,323,482		1,323,482	1
649,724		31,805,112		31,805,112	2
			125	125	3
			1	1	4
67			2,476	2,476	5
120,365		5,445,048		5,445,048	6
220		13,450	160	13,610	7
3			178	178	8
736,674		32,628,496		32,628,496	9
2,320,761		132,572,030		132,572,030	10
246,423		12,556,060		12,556,060	11
5,084			232,922	232,922	12
426		25,995		25,995	13
19			1,028	1,028	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Basin Electric Power Cooperative	SF	WSPP	NA	NA	NA
2	Bear Energy LP	SF	T-12	NA	NA	NA
3	Benton County PUD No. 1	SF	WSPP	NA	NA	NA
4	Black Hills Power, Inc.	LF	441	50	50	41
5	Black Hills Power, Inc.	OS	WSPP	NA	NA	NA
6	Black Hills Power, Inc.	SF	WSPP	NA	NA	NA
7	Blanding City	AD	T-12	NA	NA	NA
8	Blanding City	LF	T-12	1.5	NA	NA
9	Bonneville Power Administration	AD	T-11	NA	NA	NA
10	Bonneville Power Administration	AD	T-12	NA	NA	NA
11	Bonneville Power Administration	LF	543	NA	NA	NA
12	Bonneville Power Administration	LU	T-12	NA	NA	NA
13	Bonneville Power Administration	OS	370	NA	NA	NA
14	Bonneville Power Administration	OS	T-11	NA	NA	NA
	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.
31,204		1,787,447		1,787,447	1
2,155		109,210		109,210	2
6,870		309,176		309,176	3
364,826	6,112,239	4,022,898		10,135,137	4
400		19,600		19,600	5
102,486		5,379,052		5,379,052	6
			5,648	5,648	7
12,857	176,199	333,008		509,207	8
			82,733	82,733	9
			63,589	63,589	10
353,629		14,498,789		14,498,789	11
40,368		2,085,655		2,085,655	12
4,330			82,617	82,617	13
2,942			135,971	135,971	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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 Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Bonneville Power Administration	SF	T-11	NA	NA	NA
2	Bonneville Power Administration	SF	WSPP	NA	NA	NA
3	British Columbia Transmission Corp.	SF	T-13	NA	NA	NA
4	Burbank, City of	SF	WSPP	NA	NA	NA
5	California Independent System Operator	AD	T-12	NA	NA	NA
6	California Independent System Operator	SF	T-12	NA	NA	NA
7	Cargill Power Markets, LLC	OS	T-11	NA	NA	NA
8	Cargill Power Markets, LLC	OS	T-12	NA	NA	NA
9	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
10	Chelan County PUD No. 1	SF	WSPP	NA	NA	NA
11	Citigroup Energy, Inc.	SF	T-12	NA	NA	NA
12	City of Roseville	SF	WSPP	NA	NA	NA
13	Clark Public Utilities	AD	T-12	NA	NA	NA
14	Clark Public Utilities	LF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
92			5,107	5,107	1
273,760		7,146,585		7,146,585	2
33			2,619	2,619	3
137,756		6,983,194		6,983,194	4
-368			129,923	129,923	5
215,534		9,940,487		9,940,487	6
24,859			1,085,832	1,085,832	7
8,463		392,676		392,676	8
1,291,087		65,768,500		65,768,500	9
1,056		56,480		56,480	10
973,161		59,271,370		59,271,370	11
511		32,665		32,665	12
			131,801	131,801	13
789,135	2,296,826	33,589,326		35,886,152	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
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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	Clatskanie People's Utility District	SF	WSPP	NA	NA	NA
2	Colorado River Commission of Nevada	SF	WSPP	NA	NA	NA
3	Colorado Springs Utilities	OS	WSPP	NA	NA	NA
4	Colorado Springs Utilities	SF	WSPP	NA	NA	NA
5	Conoco Inc.	SF	T-12	NA	NA	NA
6	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
7	Coral Power	SF	T-11	NA	NA	NA
8	Coral Power	SF	WSPP	NA	NA	NA
9	Credit Suisse Energy LLC	SF	T-12	NA	NA	NA
10	DB Energy Trading LLC	SF	T-12	NA	NA	NA
11	Douglas County PUD No. 1	SF	WSPP	NA	NA	NA
12	Duke Energy Trading & Marketing, LLC	SF	T-12	NA	NA	NA
13	ENMAX Energy Marketing Inc.	SF	WSPP	NA	NA	NA
14	EPCOR Merchant and Capital Inc.	SF	WSPP	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7,615		348,025		348,025	1
34,065		1,180,220		1,180,220	2
2,709		113,376		113,376	3
2,865		160,529		160,529	4
219,777		11,536,020		11,536,020	5
1,521,505		84,058,939		84,058,939	6
3			159	159	7
1,661,806		92,700,646		92,700,646	8
108,000		6,833,304		6,833,304	9
245,155		12,854,127		12,854,127	10
3,005		149,760		149,760	11
19,519		1,083,147		1,083,147	12
567		9,436		9,436	13
15,354		773,157		773,157	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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	El Paso Electric Company	OS	WSPP	NA	NA	NA
2	El Paso Electric Company	SF	WSPP	NA	NA	NA
3	Eugene Water & Electric Board	OS	T-11	NA	NA	NA
4	Eugene Water & Electric Board	OS	WSPP	NA	NA	NA
5	Eugene Water & Electric Board	SF	T-11	NA	NA	NA
6	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
7	FPL Energy Power Marketing, Inc.	SF	WSPP	NA	NA	NA
8	Flathead Electric Cooperative	AD	T-12	NA	NA	NA
9	Flathead Electric Cooperative	LF	T-12	NA	NA	NA
10	Fortis Energy Marketing & Trading GP	SF	WSPP	NA	NA	NA
11	Franklin County PUD No. 1	SF	WSPP	NA	NA	NA
12	Gila River Power, L.P.	SF	WSPP	NA	NA	NA
13	Glendale, City of	SF	WSPP	NA	NA	NA
14	Grant County PUD No. 2	SF	WSPP	NA	NA	NA
	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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
670		37,355	975	38,330	1
108,419		5,472,023		5,472,023	2
4			138	138	3
		109,571		109,571	4
531			21,447	21,447	5
27,539		1,457,371		1,457,371	6
20,270		1,099,190		1,099,190	7
			-2,759	-2,759	8
111,496		4,618,376	-49,000	4,569,376	9
90,200		5,645,189		5,645,189	10
3,446		168,879		168,879	11
128,800		5,947,131		5,947,131	12
28		2,450		2,450	13
45,055		2,098,514		2,098,514	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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)	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	Grays Harbor Public Utility District	SF	WSPP	NA	NA	NA
2	Hurricane, City of	LF	T-12	NA	NA	NA
3	Idaho Power Company	AD	WSPP	NA	NA	NA
4	Idaho Power Company	IF	T-11	NA	NA	NA
5	Idaho Power Company	OS	WSPP	NA	NA	NA
6	Idaho Power Company	SF	T-11	NA	NA	NA
7	Idaho Power Company	SF	T-13	NA	NA	NA
8	Idaho Power Company	SF	WSPP	NA	NA	NA
9	J. Aron & Company	SF	T-11	NA	NA	NA
10	J. Aron & Company	SF	T-12	NA	NA	NA
11	J.P. Morgan Ventures Energy Corporation	SF	T-12	NA	NA	NA
12	Lehman Brothers Commodity Services, Inc	SF	T-12	NA	NA	NA
13	Los Angeles Dept. of Water & Power	LU	301	NA	NA	NA
14	Los Angeles Dept. of Water & Power	OS	WSPP	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
5,865		267,100		267,100	1
22,431		628,068		628,068	2
			9,550	9,550	3
2,123			89,108	89,108	4
			13,035	13,035	5
7,643			446,000	446,000	6
279			12,273	12,273	7
223,331		10,235,106		10,235,106	8
446			22,476	22,476	9
1,124,800		48,688,520		48,688,520	10
246,184		14,210,116		14,210,116	11
111,625		6,575,854		6,575,854	12
593,481		25,128,957		25,128,957	13
3,381		148,835		148,835	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Los Angeles Dept. of Water & Power	SF	WSPP	NA	NA	NA
2	Merrill Lynch Commodities, Inc.	SF	WSPP	NA	NA	NA
3	Modesto Irrigation District	SF	WSPP	NA	NA	NA
4	Morgan Stanley Capital Group, Inc.	IF	T-12	NA	NA	NA
5	Morgan Stanley Capital Group, Inc.	OS	T-12	NA	NA	NA
6	Morgan Stanley Capital Group, Inc.	SF	T-11	NA	NA	NA
7	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
8	Municipal Energy Agency of Nebraska	OS	WSPP	NA	NA	NA
9	Municipal Energy Agency of Nebraska	SF	WSPP	NA	NA	NA
10	Nevada Power Company	SF	WSPP	NA	NA	NA
11	NorthWestern Energy	SF	T-13	NA	NA	NA
12	Northern California Power Agency	SF	WSPP	NA	NA	NA
13	Northpoint Energy Solutions Inc.	SF	WSPP	NA	NA	NA
14	Occidental Power Services, Inc.	SF	WSPP	NA	NA	NA
	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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
219,212		11,844,495		11,844,495	1
199,470		10,423,970		10,423,970	2
25,320		1,406,596		1,406,596	3
96,600		3,836,095		3,836,095	4
400		22,000		22,000	5
4,864			224,797	224,797	6
7,464,319		383,725,629		383,725,629	7
510		21,150		21,150	8
14,557		803,155		803,155	9
387,084		23,444,867		23,444,867	10
579			31,768	31,768	11
110,353		8,998,796		8,998,796	12
23,200		1,089,320		1,089,320	13
12,393		700,935		700,935	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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)	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	PPL Energy Plus, LLC	SF	WSPP	NA	NA	NA
2	PPL Montana, LLC	OS	WSPP	NA	NA	NA
3	PPL Montana, LLC	SF	T-11	NA	NA	NA
4	PPL Montana, LLC	SF	WSPP	NA	NA	NA
5	PPM Energy, Inc.	AD	T-11	NA	NA	NA
6	PPM Energy, Inc.	LF	T-11	NA	NA	NA
7	PPM Energy, Inc.	SF	T-11	NA	NA	NA
8	PPM Energy, Inc.	SF	WSPP	NA	NA	NA
9	Pacific Gas & Electric Company	SF	WSPP	NA	NA	NA
10	Pacific Northwest Gen. Cooperative	SF	WSPP	NA	NA	NA
11	Pasadena, City of	SF	WSPP	NA	NA	NA
12	Pinnacle West Capital Corporation	SF	T-12	NA	NA	NA
13	Portland General Electric Co.	OS	T-12	NA	NA	NA
14	Portland General Electric Co.	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
23,800		1,301,550		1,301,550	1
1,625		88,095	480	88,575	2
1,972			90,116	90,116	3
53,653		2,645,411		2,645,411	4
3,350			233,424	233,424	5
17,051			770,164	770,164	6
11,821			546,975	546,975	7
290,846		13,503,947	-49,132	13,454,815	8
57,353		2,981,011		2,981,011	9
10,715		528,945		528,945	10
4,174		267,590		267,590	11
315,425		24,865,948		24,865,948	12
9		428	540	968	13
34			1,831	1,831	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Portland General Electric Co.	SF	T-12	NA	NA	NA
2	Portland General Electric Co.	SF	T-13	NA	NA	NA
3	Powerex	AD	WSPP	NA	NA	NA
4	Powerex	IF	T-11	NA	NA	NA
5	Powerex	OS	T-11	NA	NA	NA
6	Powerex	OS	WSPP	NA	NA	NA
7	Powerex	SF	WSPP	NA	NA	NA
8	Public Service Company of Colorado	LF	320	176	176	170
9	Public Service Company of Colorado	OS	T-11	NA	NA	NA
10	Public Service Company of Colorado	OS	WSPP	NA	NA	NA
11	Public Service Company of Colorado	SF	WSPP	NA	NA	NA
12	Public Service Company of New Mexico	OS	WSPP	NA	NA	NA
13	Public Service Company of New Mexico	SF	WSPP	NA	NA	NA
14	Puget Sound Energy	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
494,283		27,890,206		27,890,206	1
70			3,738	3,738	2
			-325	-325	3
13,611			620,187	620,187	4
11,958			596,617	596,617	5
689		20,608		20,608	6
1,521,624		72,042,094		72,042,094	7
1,150,736	28,110,720	31,372,880		59,483,600	8
3,380			136,817	136,817	9
5,607		234,920		234,920	10
570,727		28,980,419		28,980,419	11
2,665		132,475	3,700	136,175	12
443,900		21,972,895		21,972,895	13
37			1,933	1,933	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Puget Sound Energy	SF	WSPP	NA	NA	NA
2	Rainbow Energy Marketing	SF	T-11	NA	NA	NA
3	Rainbow Energy Marketing	SF	WSPP	NA	NA	NA
4	Redding, City of	SF	WSPP	NA	NA	NA
5	SUEZ Energy Marketing NA, Inc.	SF	WSPP	NA	NA	NA
6	Sacramento Municipal Utility District	AD	250	NA	NA	NA
7	Sacramento Municipal Utility District	LF	250	NA	NA	NA
8	Sacramento Municipal Utility District	SF	WSPP	NA	NA	NA
9	Salt River Project	IF	WSPP	NA	NA	NA
10	Salt River Project	OS	WSPP	NA	NA	NA
11	Salt River Project	SF	WSPP	NA	NA	NA
12	San Diego Gas & Electric	SF	WSPP	NA	NA	NA
13	Santa Clara, City of	SF	WSPP	NA	NA	NA
14	Seattle City Light `	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
352,469		16,785,494		16,785,494	1
1,593			70,006	70,006	2
21,200		1,040,840		1,040,840	3
675		39,374		39,374	4
118,151		5,998,357		5,998,357	5
			288,137	288,137	6
530,157		9,797,301		9,797,301	7
77,932		3,598,561		3,598,561	8
73,200		3,354,126		3,354,126	9
8,650		429,185		429,185	10
503,277		26,618,878		26,618,878	11
5,161		310,095		310,095	12
41,476		2,363,416		2,363,416	13
78			3,287	3,287	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Seattle City Light	SF	WSPP	NA	NA	NA
2	Sempra Energy Solutions	SF	WSPP	NA	NA	NA
3	Sempra Energy Trading Corp.	OS	T-11	NA	NA	NA
4	Sempra Energy Trading Corp.	SF	T-12	NA	NA	NA
5	Sempra Generation	SF	T-12	NA	NA	NA
6	Sierra Pacific Power Company	AD	258	NA	NA	NA
7	Sierra Pacific Power Company	AD	267	NA	NA	NA
8	Sierra Pacific Power Company	AD	T-11	NA	NA	NA
9	Sierra Pacific Power Company	AD	T-13	NA	NA	NA
10	Sierra Pacific Power Company	LF	258	75	77	69
11	Sierra Pacific Power Company	LF	267	NA	NA	NA
12	Sierra Pacific Power Company	LF	T-11	NA	NA	NA
13	Sierra Pacific Power Company	OS	WSPP	NA	NA	NA
14	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
	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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
71,001		3,522,216		3,522,216	1
41,920		2,091,394		2,091,394	2
8,271			404,481	404,481	3
4,164,107		254,640,684		254,640,684	4
14,000		746,400		746,400	5
			-720,900	-720,900	6
-1,832			26,304	26,304	7
			-9,918	-9,918	8
			-2,483	-2,483	9
459,900	15,102,000	16,432,227		31,534,227	10
132		5,982		5,982	11
790			36,691	36,691	12
5,958		262,738		262,738	13
26,243			1,305,181	1,305,181	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
2	Sierra Pacific Power Company	SF	WSPP	NA	NA	NA
3	Snohomish Public Utility District No. 1	SF	WSPP	NA	NA	NA
4	Southern California Edison Company	LF	248	NA	NA	NA
5	Southern California Edison Company	SF	T-12	NA	NA	NA
6	Southwestern Public Service Company	SF	WSPP	NA	NA	NA
7	State of California Department of	SF	WSPP	NA	NA	NA
8	Water Resources					
9	Tacoma, City of	SF	WSPP	NA	NA	NA
10	The Cincinnati Gas & Electric Company	SF	WSPP	NA	NA	NA
11	TransAlta Energy Marketing Inc.	SF	T-11	NA	NA	NA
12	TransAlta Energy Marketing Inc.	SF	WSPP	NA	NA	NA
13	Tri-State Generation & Transmission	OS	WSPP	NA	NA	NA
14	Tri-State Generation & Transmission	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
8			445	445	1
479,260		25,966,951		25,966,951	2
30,825		1,487,325		1,487,325	3
736,000		44,160,000		44,160,000	4
11,770		661,470		661,470	5
11,638		848,118		848,118	6
18,400		1,202,792		1,202,792	7
					8
3,580		132,931		132,931	9
90,320		4,551,550		4,551,550	10
30			1,507	1,507	11
636,690		34,029,950	24,500	34,054,450	12
5,458		290,463		290,463	13
655			28,413	28,413	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	Tri-State Generation & Transmission	SF	WSPP	0.7	0.7	0.2
2	Tucson Electric Power	OS	WSPP	NA	NA	NA
3	Tucson Electric Power	SF	WSPP	NA	NA	NA
4	Turlock Irrigation District	SF	WSPP	NA	NA	NA
5	UBS Warburg Energy LLC	SF	T-12	NA	NA	NA
6	Utah Associated Municipal Power Systems	IU	WSPP	NA	NA	NA
7	Utah Associated Municipal Power Systems	OS	WSPP	NA	NA	NA
8	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
9	Utah Associated Municipal Power Systems	SF	WSPP	NA	NA	NA
10	Utah Municipal Power Agency	LF	433	34	34	34
11	Utah Municipal Power Agency	SF	T-3	NA	NA	NA
12	Western Area Power Administration	LF	T-11	NA	NA	NA
13	Western Area Power Administration	OS	WSPP	NA	NA	NA
14	Western Area Power Administration	SF	T-11	NA	NA	NA
	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
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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.
186,490	36,949	10,328,929		10,365,878	1
532		30,003		30,003	2
79,130		4,598,164		4,598,164	3
20,225		1,085,884		1,085,884	4
1,410,504		84,977,271		84,977,271	5
17,509		665,342		665,342	6
495		22,815		22,815	7
13			473	473	8
12,344		687,970		687,970	9
218,884	4,396,200	5,086,864		9,483,064	10
4,149		227,349		227,349	11
30			905	905	12
7,302		362,057		362,057	13
10			292	292	14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administration	SF	WSPP	NA	NA	NA
2	Weyerhaeuser	IF	T-11	NA	NA	NA
3	Bookout Sales	AD	NA	NA	NA	NA
4	Bookout Sales	SF	NA	NA	NA	NA
5	Test Generation	OS	NA	NA	NA	NA
6	Trade Sales	AD	NA	.NA	NA	NA
7	Trade Sales	SF	NA	NA	NA	NA
8	Accrual True-up	NA	NA	NA	NA	NA
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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.
138,173		8,041,381		8,041,381	1
25,019			1,135,743	1,135,743	2
-632			-241,757	-241,757	3
-26,277,378			-1,004,967,209	-1,004,967,209	4
-238,660			-12,125,197	-12,125,197	5
			-1,400	-1,400	6
			-363,399,842	-363,399,842	7
-122,531			16,988,282	16,988,282	8
					9
					10
					11
					12
					13
					14
216,028	3,241,633	4,497,870	-615	7,738,888	
13,440,509	56,231,133	2,042,326,068	-1,355,391,397	743,165,804	
13,656,537	**59,472,766**	**2,046,823,938**	**-1,355,392,012**	**750,904,692**	

Schedule Page: 310 Line No.: 7 Column: j

Settlement Adjustment

Schedule Page: 310 Line No.: 11 Column: j

Accrual True-up

Schedule Page: 310 Line No.: 12 Column: j

Liquidated Damages

Schedule Page: 310 Line No.: 14 Column: b

Arizona Public Service Co. - FERC - T-12 - Contract termination date: December 31, 2006.

Schedule Page: 310.1 Line No.: 1 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 3 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 3 Column: j

Operating Reserves

Schedule Page: 310.1 Line No.: 4 Column: j

Transmission Losses

Schedule Page: 310.1 Line No.: 5 Column: j

Reserve Share

Schedule Page: 310.1 Line No.: 7 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 7 Column: j

Operating Reserves

Schedule Page: 310.1 Line No.: 8 Column: j

Transmission Losses

Schedule Page: 310.1 Line No.: 12 Column: b

Basin Electric Power Company - FERC - T-11 [Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 233)] - Contract termination date: 12 months notification.

Schedule Page: 310.1 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.1 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 4 Column: b

Black Hills Power & Light Company - FERC 236 - Contract termination date: December 31, 2023.

Schedule Page: 310.2 Line No.: 5 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.2 Line No.: 7 Column: b

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 7 Column: j

Settlement Adjustment

Schedule Page: 310.2 Line No.: 8 Column: b

Blanding City - FERC T-12 - Contract termination date: March 1, 2007.

Schedule Page: 310.2 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 9 Column: j

Settlement Adjustment

Schedule Page: 310.2 Line No.: 10 Column: b

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 10 Column: j

Settlement Adjustment

Schedule Page: 310.2 Line No.: 11 Column: b

Bonneville Power Administration - FERC 543 - Contract termination date: September 30, 2006.

Schedule Page: 310.2 Line No.: 12 Column: b

Bonneville Power Administration - FERC T-12 - Contract termination date: April 22, 2024.

Schedule Page: 310.2 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.2 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.2 Line No.: 14 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.2 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 1 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 3 Column: j

Reserve Share

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

Settlement Adjustment.

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

Settlement Adjustment

Schedule Page: 310.3 Line No.: 7 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.3 Line No.: 7 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 8 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.3 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 13 Column: j

Settlement Adjustment

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

Clark County PUD #1 - FERC T-12 - Contract termination date: December 12, 2007.

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

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

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

Transmission Losses

Schedule Page: 310.5 Line No.: 1 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.5 Line No.: 1 Column: j

Operating Reserves

Schedule Page: 310.5 Line No.: 3 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.5 Line No.: 3 Column: j

Transmission Losses

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

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.5 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 8 Column: j
Settlement Adjustment

Schedule Page: 310.5 Line No.: 9 Column: b
Flathead Electric Cooperative, Inc. - FERC T-12 - Contract termination date: September 30, 2006.

Schedule Page: 310.5 Line No.: 9 Column: j
Unauthorized Use Charge

Schedule Page: 310.6 Line No.: 2 Column: b
Hurricane, City of - FERC T-12 - Contract termination date: August 31, 2007.

Schedule Page: 310.6 Line No.: 3 Column: b
Settlement Adjustment.

Schedule Page: 310.6 Line No.: 3 Column: j
Settlement Adjustment

Schedule Page: 310.6 Line No.: 4 Column: b
Idaho Power Company - FERC - T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212)] - Contract termination date: May 31, 2009.

Schedule Page: 310.6 Line No.: 4 Column: j
Transmission Losses

Schedule Page: 310.6 Line No.: 5 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.6 Line No.: 5 Column: j
Operating Reserves

Schedule Page: 310.6 Line No.: 6 Column: j
Transmission Losses

Schedule Page: 310.6 Line No.: 7 Column: j
Reserve Share

Schedule Page: 310.6 Line No.: 9 Column: j
Transmission Losses

Schedule Page: 310.6 Line No.: 13 Column: b
Los Angeles Department of Water and Power - FERC 301 - Contract termination date: June 15, 2027.

Schedule Page: 310.6 Line No.: 14 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.7 Line No.: 4 Column: b
Morgan Stanley Capital Group, Inc. - FERC - T-12 - Contract terminination date: December 31, 2006.

Schedule Page: 310.7 Line No.: 5 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.7 Line No.: 6 Column: j
Transmission Losses

Schedule Page: 310.7 Line No.: 8 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.7 Line No.: 11 Column: j
Reserve Share

Schedule Page: 310.8 Line No.: 2 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.8 Line No.: 2 Column: j
Operating Reserves

Schedule Page: 310.8 Line No.: 3 Column: j
Transmission Losses

Schedule Page: 310.8 Line No.: 5 Column: b
Settlement Adjustment and PPM Energy was an affiliate of the respondent through March 20, 2006.

Schedule Page: 310.8 Line No.: 5 Column: j
Settlement Adjustment

Schedule Page: 310.8 Line No.: 6 Column: b

PPM Energy - FERC - T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279)] - Contract termination date: 12 months written notification. PPM Energy was an affiliate of the respondent through March 20, 2006.

Schedule Page: 310.8 Line No.: 6 Column: j

Transmission Losses and Unauthorized Use Charge

Schedule Page: 310.8 Line No.: 7 Column: b

PPM Energy was an affiliate of the respondent through March 20, 2006.

Schedule Page: 310.8 Line No.: 7 Column: j

Transmission Losses

Schedule Page: 310.8 Line No.: 8 Column: b

PPM Energy was an affiliate of the respondent through March 20, 2006.

Schedule Page: 310.8 Line No.: 8 Column: j

Liquidated Damages

Schedule Page: 310.8 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.8 Line No.: 13 Column: j

Operating Reserves

Schedule Page: 310.8 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 2 Column: j

Reserve Share

Schedule Page: 310.9 Line No.: 3 Column: b

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 3 Column: j

Settlement Adjustment

Schedule Page: 310.9 Line No.: 4 Column: b

PowerEX - FERC - T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169)] - Contract termination date: September 30, 2007.

Schedule Page: 310.9 Line No.: 4 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 5 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 6 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 8 Column: b

Public Service Company of Colorado - FERC 320 - Contract termination date: December 31, 2011.

Schedule Page: 310.9 Line No.: 9 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 9 Column: j

Transmission Losses

Schedule Page: 310.9 Line No.: 10 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 12 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 12 Column: j

Operating Reserves

Schedule Page: 310.9 Line No.: 14 Column: j

Reserve Share

Schedule Page: 310.10 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.10 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.10 Line No.: 7 Column: b

Sacramento Municipal Utility District - FERC 250 - Contract termination date: December 31, 2014.

Schedule Page: 310.10 Line No.: 9 Column: b

Salt River Project - WSPP - Contract termination date: December 31, 2009.

Schedule Page: 310.10 Line No.: 10 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.10 Line No.: 14 Column: j

Reserve Share

Schedule Page: 310.11 Line No.: 3 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.11 Line No.: 3 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.11 Line No.: 7 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 7 Column: j

Settlement Adjustment

Schedule Page: 310.11 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 8 Column: j

Settlement Adjustment

Schedule Page: 310.11 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 9 Column: j

Settlement Adjustment

Schedule Page: 310.11 Line No.: 10 Column: b

Sierra Pacific Power Company - FERC 258 - Contract termination date: February 28, 2009.

Schedule Page: 310.11 Line No.: 11 Column: b

Sierra Pacific Power Company - FERC 267 - Contract termination date: April 30, 2021.

Schedule Page: 310.11 Line No.: 12 Column: b

Sierra Pacific Power Company - FERC - T-11 [Pavant Capacitor Ownership, Operation and Maintenance Letter Agreement dated November 9, 2000] - Contract termination date: 90 days notification.

Schedule Page: 310.11 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.11 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.12 Line No.: 1 Column: j

Reserve Share

Schedule Page: 310.12 Line No.: 4 Column: b

Southern California Edison Company - FERC 248 - Contract termination date: September 30, 2006.

Schedule Page: 310.12 Line No.: 11 Column: j

Transmission Losses

Schedule Page: 310.12 Line No.: 12 Column: j

Liquidated Damages

Schedule Page: 310.12 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.12 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.13 Line No.: 2 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 7 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 8 Column: j

Transmission Losses

Schedule Page: 310.13 Line No.: 10 Column: b

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.13 Line No.: 12 Column: b

Western Area Power Administration - FERC -T-11 [Evergreen Network Transmission Service under Transmission Service and Operating Agreement for network service in PACE] - Contract termination date: 90 days notification.

Schedule Page: 310.13 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.13 Line No.: 13 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 14 Column: j

Transmission Losses

Schedule Page: 310.14 Line No.: 2 Column: b

Weyerhaeuser - FERC - T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 320)] - Contract termination date: December 31, 2006.

Schedule Page: 310.14 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.14 Line No.: 3 Column: b

Settlement Adjustment.

Schedule Page: 310.14 Line No.: 3 Column: j

Settlement Adjustment

Schedule Page: 310.14 Line No.: 4 Column: j

Recognition and reporting of gains and losses on bookouts under EITF Issue No. 03-11

Schedule Page: 310.14 Line No.: 5 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.14 Line No.: 5 Column: j

The negative revenue reported on this line reflects test energy generated at the Current Creek and Leaning Juniper power plants that were transferred to construction. Energy generated during testing was delivered to PacifiCorp's electric system for sale, as required by the guidance in 18 CFR Electric Plant Instructions 18(a), is a component of construction and is the fair value of the energy delivered.

Schedule Page: 310.14 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.14 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.14 Line No.: 7 Column: j

Recognition and reporting of gains and losses on energy trading contracts under EITF Issue No. 02-03.

Schedule Page: 310.14 Line No.: 8 Column: j

Accrual True-up

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	22,686,191	24,017,124
5	(501) Fuel	485,079,578	460,560,601
6	(502) Steam Expenses	32,320,388	34,694,613
7	(503) Steam from Other Sources	3,110,724	4,211,469
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,215,404	4,028,397
10	(506) Miscellaneous Steam Power Expenses	30,690,672	17,294,691
11	(507) Rents	1,173,471	880,309
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	579,276,428	545,687,204
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	7,604,360	7,374,328
16	(511) Maintenance of Structures	19,475,953	16,716,514
17	(512) Maintenance of Boiler Plant	90,246,837	88,150,437
18	(513) Maintenance of Electric Plant	32,506,692	30,895,424
19	(514) Maintenance of Miscellaneous Steam Plant	11,617,137	9,458,599
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	161,450,979	152,595,302
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	740,727,407	698,282,506
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	7,448,958	4,448,802
45	(536) Water for Power	241,545	155,594
46	(537) Hydraulic Expenses	4,629,403	4,376,778
47	(538) Electric Expenses	3,787	20,996
48	(539) Miscellaneous Hydraulic Power Generation Expenses	15,883,249	17,237,689
49	(540) Rents	94,633	175,519
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	28,301,575	26,415,378
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures	1,072,249	1,088,138
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,435,262	1,919,845
56	(544) Maintenance of Electric Plant	948,267	2,537,342
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,543,440	2,582,641
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,999,218	8,127,966
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	34,300,793	34,543,344

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 05/17/2007	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	1,170,218	586,268
63	(547) Fuel	129,693,593	61,461,763
64	(548) Generation Expenses	12,202,052	10,263,205
65	(549) Miscellaneous Other Power Generation Expenses	2,930,812	1,473,786
66	(550) Rents	13,642,417	17,319,501
67	TOTAL Operation (Enter Total of lines 62 thru 66)	159,639,092	91,104,523
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	239,024	191,273
71	(553) Maintenance of Generating and Electric Plant	2,562,314	1,424,850
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	436,088	249,513
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,237,426	1,865,636
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	162,876,518	92,970,159
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	707,454,156	674,794,888
77	(556) System Control and Load Dispatching	2,484,435	1,451,461
78	(557) Other Expenses	54,585,469	46,131,142
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	764,524,060	722,377,491
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,702,428,778	1,548,173,500
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	7,758,555	6,457,151
84	(561) Load Dispatching	1,087,335	4,512,428
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	4,161,724	
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	805,928	
91	(561.7) Generation Interconnection Studies	507,258	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	320,015	569,390
94	(563) Overhead Lines Expenses	2,320,087	2,188,772
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	94,110,633	83,360,299
97	(566) Miscellaneous Transmission Expenses	938,870	191,619
98	(567) Rents	1,343,348	2,028,958
99	TOTAL Operation (Enter Total of lines 83 thru 98)	113,353,753	99,308,617
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	19,767	11,686
102	(569) Maintenance of Structures	5,318	97
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	132,256	
105	(569.3) Maintenance of Communication Equipment	1,820,947	
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	10,062,229	6,520,157
108	(571) Maintenance of Overhead Lines	10,812,758	8,587,820
109	(572) Maintenance of Underground Lines		6,599
110	(573) Maintenance of Miscellaneous Transmission Plant	723,453	847,821
111	TOTAL Maintenance (Total of lines 101 thru 110)	23,576,728	15,974,180
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	136,930,481	115,282,797

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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)
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	25,372,966	25,226,709
135	(581) Load Dispatching	12,310,097	9,786,336
136	(582) Station Expenses	3,155,806	3,301,836
137	(583) Overhead Line Expenses	17,529,369	18,348,654
138	(584) Underground Line Expenses	1,527,073	1,514,228
139	(585) Street Lighting and Signal System Expenses	149,307	192,851
140	(586) Meter Expenses	5,126,900	5,033,168
141	(587) Customer Installations Expenses		17,640
142	(588) Miscellaneous Expenses	14,857,820	20,626,608
143	(589) Rents	3,324,851	3,168,615
144	TOTAL Operation (Enter Total of lines 134 thru 143)	83,354,189	87,216,645
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,510,144	711,039
147	(591) Maintenance of Structures	2,312,953	2,101,838
148	(592) Maintenance of Station Equipment	12,350,005	10,416,491
149	(593) Maintenance of Overhead Lines	85,581,466	54,444,188
150	(594) Maintenance of Underground Lines	22,275,933	20,517,510
151	(595) Maintenance of Line Transformers	36,634	175,108
152	(596) Maintenance of Street Lighting and Signal Systems	4,115,843	4,454,472
153	(597) Maintenance of Meters	5,100,036	4,279,992
154	(598) Maintenance of Miscellaneous Distribution Plant	1,183,218	17,281,723
155	TOTAL Maintenance (Total of lines 146 thru 154)	135,466,232	114,382,361
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	218,820,421	201,599,006
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	10,719,527	7,940,111
160	(902) Meter Reading Expenses	26,828,346	23,835,530
161	(903) Customer Records and Collection Expenses	52,949,192	51,082,123
162	(904) Uncollectible Accounts	16,093,297	7,232,503
163	(905) Miscellaneous Customer Accounts Expenses	1,273,970	1,134,759
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	107,864,332	91,225,026

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	05/17/2007	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	1,301,809	2,932,798
168	(908) Customer Assistance Expenses	47,710,915	44,489,026
169	(909) Informational and Instructional Expenses	3,620,675	614,258
170	(910) Miscellaneous Customer Service and Informational Expenses	105,971	262,985
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	52,739,370	48,299,067
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	142,943,825	137,354,536
182	(921) Office Supplies and Expenses	10,053,431	12,087,468
183	(Less) (922) Administrative Expenses Transferred-Credit	23,386,081	28,826,830
184	(923) Outside Services Employed	18,460,427	27,876,349
185	(924) Property Insurance	23,392,399	20,388,933
186	(925) Injuries and Damages	10,053,945	10,918,589
187	(926) Employee Pensions and Benefits		31,743
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,435,094	8,756,397
190	(929) (Less) Duplicate Charges-Cr.	9,571,778	15,441,595
191	(930.1) General Advertising Expenses	1,693,669	1,796,122
192	(930.2) Miscellaneous General Expenses	25,696,241	35,008,141
193	(931) Rents	8,197,293	7,853,508
194	TOTAL Operation (Enter Total of lines 181 thru 193)	215,968,465	217,739,875
195	Maintenance		
196	(935) Maintenance of General Plant	22,676,043	18,968,997
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	238,644,508	236,708,872
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,457,427,890	2,241,288,268

Schedule Page: 320 Line No.: 187 Column: b

Pensions and benefits are charged to functional accounts, which is consistent to where labor is charged. The following table summarizes the pension and benefit expense that was charged to the functional accounts.

	Twelve Months Ending December 31, 2006	Twelve Months Ending December 31, 2005
Pension & Benefits Expense	$ 172,724,970	$ 150,348,149

Schedule Page: 320 Line No.: 187 Column: c

The $(31,743) in pension and benefit expense for the twelve months ending December 31, 2005 represents a reclassification of a December 31, 2004 entry in January 2005.