ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

RECEIVED
2010 JUN -3 AM 9:41
IDAHO PUBLIC
UTILITIES COMMISSION

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

June 3, 2010

VIA OVERNIGHT DELIVERY

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

Attention: Jean D. Jewell
Commission Secretary

RE: FERC Form 1

PacifiCorp (d.b.a. Rocky Mountain Power) submits for filing one copy of PacifiCorp's annual FERC Form 1 report for the year ended December 31, 2009.

PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By email (**preferred**): datarequest@pacificorp.com

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

Please direct any informal questions to Ted Weston, Regulatory Manager, at (801) 220-2963.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Enclosure

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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

PAC-E

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UTILITIES COMMISSION

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
PacifiCorp	End of 2009/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	02 Year/Period of Report
PacifiCorp	End of 2009/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	06 Title of Contact Person
Henry E. Lay	Corporate 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) ☒ An Original (2) ☐ A Resubmission	04/14/2010

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)*
Douglas K. Stuver	Douglas K. Stuver	04/14/2010
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	N/A
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	N/A
56	Amounts included in ISO/RTO Settlement Statements	397	N/A
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	N/A
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

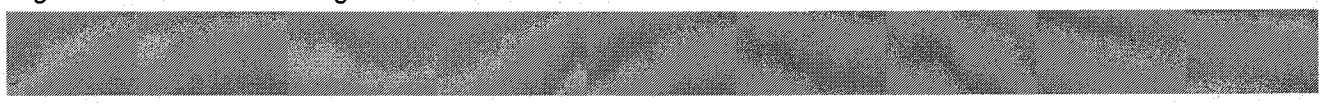
GENERAL INFORMATION

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.

Douglas K. Stuver, 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.



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

Not applicable

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

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation and commercial and trading functions are operated 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) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

FOOTNOTE DATA

Schedule Page: 101 Line No.: 1 Column: Item 2

PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly-formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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%) (89.5% controlled by Berkshire Hathaway Inc.)

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

PacifiCorp (100% of common stock held 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	04/14/2010	End of 2009/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	100	
8	PacifiCorp Future Generations, Inc.	Rain Forest Carbon Credits	100	
9	PacifiCorp Investment Management, Inc.	Management Services	100	
10	Trapper Mining, Inc.	Mining	21.40	
11	PacifiCorp Foundation	Not-for-profit foundation		
12				
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27				

FOOTNOTE DATA

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

Pacific Minerals, Inc. ("PMI") is a wholly owned subsidiary of PacifiCorp that holds a 66.67% ownership interest in Bridger Coal Company, a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company.

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

Effective December 31, 2009, PacifiCorp Future Generations, Inc. and its subsidiary Canopy Botanicals, Inc. were dissolved.

Schedule Page: 103 Line No.: 9 Column: a

Previously preformed management services for PERCo, no longer active.

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

PacifiCorp is a minority owner in Trapper Mining, Inc., a cooperative; the members are Salt River Project Agricultural Improvement and Power District (32.10%), Tri-State Generation and Transmission Association, Inc. (26.57%), Platte River Power Authority (19.93%) and PacifiCorp (21.40%).

Schedule Page: 103 Line No.: 11 Column: c

The PacifiCorp Foundation (the "Foundation") is controlled by PacifiCorp as two of the Foundation's directors are also directors of PacifiCorp and the majority of the Foundation's remaining directors are employees of PacifiCorp.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/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, 2009		
2	Chairman of the Board and Chief Executive Officer	Gregory E. Abel	
3	Senior Vice President and Chief Financial Officer	Douglas K. Stuver	228,800
4	President, Rocky Mountain Power	A. Richard Walje	351,900
5	President, Pacific Power	R. Patrick Reiten	265,740
6	President, PacifiCorp Energy	A. Robert Lasich	236,000
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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, 2009, consistent with Item 402 of Regulation S-K promulgated by the Securities and Exchange Commission in its Annual Report on Form 10-K. Salary information of other officers will be provided to the Federal Energy Regulatory Commission (the "FERC") 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

Mr. Abel receives no direct compensation from PacifiCorp. PacifiCorp reimburses MidAmerican Energy Holdings Company ("MEHC") for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, 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, 2009 (File No. 001-14881) for executive compensation information for Mr. Abel.

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. On January 13, 2010, Mr. Lasich resigned as President of PacifiCorp Energy and as a director of PacifiCorp effective February 1, 2010.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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, 2009:	
2	Gregory E. Abel (Chairman of the Board and CEO, PacifiCorp)	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309
3	R. Patrick Reiten (President, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
4	A. Richard Walje (President, Rocky Mountain Power)	201 South Main, Suite 2300, Salt Lake City, Utah 84111
5	Douglas L. Anderson	302 South 36th Street, Omaha, Nebraska 68131
6	Brent E. Gale (Senior Vice President)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
7	Patrick J. Goodman	666 Grand Avenue, Suite DM29, Des Moines, Iowa 50309
8	A. Robert Lasich (President, PacifiCorp Energy)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
9	Mark C. Moench (SVP and General Counsel, PacifiCorp)	201 South Main, Suite 2400, Salt Lake City, Utah 84111
10	Natalie L. Hocken (VP and General Counsel, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
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FOOTNOTE DATA

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

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

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

For additional information regarding changes in the status of PacifiCorp's directors refer to page 108, *Important Changes During the Year*, Item 13, of this Form No. 1. On January 13, 2010, Mr. Lasich resigned as President of PacifiCorp Energy and as a director of PacifiCorp effective February 1, 2010.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES

FERC Rate Schedule/Tariff Number FERC Proceeding

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

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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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	04/14/2010	End of 2009/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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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	04/14/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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]			
None			
Idaho [b]			
None			
Oregon [c]			
Myrtle Point	04/22/2009	04/22/2029	5.0%
Philomath	08/01/2009	08/01/2019	7.0%
Jefferson	12/08/2009	12/08/2029	7.0%
Hood River	12/11/2009	12/11/2029	5.0%
Lebanon	12/22/2009	12/22/2019	5.94%
Utah [b]			
Washington Terrace	01/27/2009	01/27/2019	6.0%
Hyde Park	03/27/2009	03/27/2034	-
South Salt Lake City	04/21/2009	04/21/2034	6.0%
Wales	10/26/2009	10/26/2034	-
Moab	10/28/2009	10/28/2024	3.0%
Lehi (IM Flash Plant)	11/02/2009	11/02/2010 [e]	6.0%
Gunnison	12/08/2009	12/08/2034	6.0%
Centerfield	12/08/2009	12/08/2034	6.0%
Oakley	12/14/2009	12/14/2024	-
Washington [b]			
None			
Wyoming [d]			
Rolling Hills	08/11/2009	08/11/2034	2.0%

(a) In California, franchise fees are an expense to PacifiCorp and are embedded in rates.
(b) In Idaho, Utah and Washington, PacifiCorp collects franchise fees from customers and remits them directly to the applicable municipalities.
(c) In Oregon, the first 3.5% of the franchise fees is an expense to PacifiCorp and is embedded in rates. Any amount above the 3.5% is collected from customers and remitted directly to the applicable municipalities.
(d) In Wyoming, the first 1.0% of the franchise fees is an expense to PacifiCorp and is embedded in rates. Any amount above the 1.0% is collected from customers and remitted directly to the applicable municipalities.
(e) The initial term of the agreement is one year from the effective date. It will automatically renew each year for seven consecutive years, unless either party gives appropriate notice to terminate.

ITEM 2.

Acquisition of Ownership in Other Companies

On September 15, 2008, after having received the requisite regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC ("Chehalis"), an entity owning a 520-megawatt ("MW") natural gas-fired generating facility located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the facility, which was included in account 102, Electric plant purchased or sold. Chehalis was merged into PacifiCorp immediately following the acquisition. The results of the facility's operations have been included in PacifiCorp's financial statements since the acquisition date. In May 2009, the Federal Energy Regulatory Commission (the "FERC") approved the journal entries called for by the Uniform System of Accounts, with modifications to the purchase accounting adjustments for asset retirement obligations. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold and recorded the purchase to the appropriate plant accounts. Commission authorizations associated with the acquisition were as follows:

- Federal Trade Commission - Transaction identification number 20081103, granted May 9, 2008.
- FERC - Docket No. EC08-82-000, issued July 17, 2008.
- Washington Energy Facility Site Evaluation Council - Order No. 836, effective July 8, 2008.
- Federal Communications Commission - File number 0003447617, consent dated May 23, 2008.
- Oregon Public Utility Commission (the "OPUC") - Order No. 08-376, effective July 17, 2008, granting the petition for waiver of the OPUC's competitive bidding guidelines.
- Utah Public Service Commission (the "UPSC") - Docket No. 08-035-35, dated August 30, 2008, granting the request for approval to acquire a significant energy resource.

ITEM 3.

Purchase or Sale of an Operating Unit or System

In August 2009, PacifiCorp received FERC approval in Docket Nos. EC09-86-000 and EC09-86-001, pursuant to section 203 of the Federal Power Act, for the acquisition of a portion of a 69-kilovolt ("kV") electric transmission facility from Garkane Energy Cooperative, Inc. The acquisition was completed in September 2009. The purchase included electric transmission line facilities from, and including, the interconnect point at the Clifton Wilson substation located in Hurricane, Utah to the Twin Cities substation located in Hildale, Utah. In February 2010, the FERC approved the journal entries called for by the Uniform System of Accounts in Docket No. AC10-44-000. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold and recorded the purchase to the appropriate plant accounts.

ITEM 4.

Important Leaseholds

None.

ITEM 5.

Important Extension or Reduction of Transmission System or Distribution Territory

For discussion of transmission lines added during the year, refer to pages 424-425 of this Form No. 1. During the year ended December 31, 2009, PacifiCorp did not significantly increase or decrease its distribution territory.

ITEM 6.

Financing Activities

Short-Term Debt and Revolving Credit Agreements

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had no short-term debt outstanding as of December 31, 2009 compared to $85 million outstanding as of December 31, 2008 at a weighted-average interest rate of 1%. The decrease in short-term debt was primarily due to the proceeds from the issuance of long-term debt and $125 million of capital contributions received from MEHC during the period, partially offset by capital expenditures and maturities of long-term debt in excess of net cash provided by operating activities.

Commission authorizations for up to $1.5 billion outstanding at any one time in commercial paper and other unsecured short-term debt are as follows:

- OPUC - Docket No. UF-4120, Order No. 98-158, dated April 16, 1998.
- Washington Utilities and Transportation Commission (the "WUTC") - Docket No. UE-980404, dated April 8, 1998.
- Idaho Public Utilities Commission (the "IPUC") - Case No. PAC-E-06-01, Order No. 29999, dated March 14, 2006.
- FERC - Docket No. ES07-61-000, dated November 26, 2007, letter order effective January 1, 2008 through December 31, 2009.
- FERC - Docket No. ES09-50-000, dated October 9, 2009, letter order effective January 1, 2010 through December 31, 2011.

PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2009 or 2008.

For further discussion, refer to Note 8 of Notes to Financial Statements in this Form No. 1.

Long-Term Debt

In addition to the debt issuances discussed herein, PacifiCorp made scheduled repayments on long-term debt totaling $138 million and $412 million during the years ended December 31, 2009 and 2008, respectively.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. State commission authorizations for this issuance were as follows:

- OPUC - Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.
- IPUC - Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

As of December 31, 2009, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2009 and expire periodically through May 2012.

In March 2010, PacifiCorp received regulatory authority from the IPUC to issue an additional $2.0 billion of long-term debt through February 28, 2015. PacifiCorp has regulatory authority from the OPUC to issue an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. State commission authorizations are as follows:

- OPUC - Docket No. UF-4262, Order No. 10-062, dated February 23, 2010.
- IPUC - Case No. PAC-E-10-02, Order No. 31018, dated March 5, 2010.

PacifiCorp may from time to time seek to acquire its outstanding debt securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by PacifiCorp may be reissued or resold by PacifiCorp from time to time and will depend on prevailing market conditions, PacifiCorp's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

ITEM 7.

Changes in Articles of Incorporation or Amendments to Charter

None.

ITEM 8.

Estimated Annual Effect of Significant Wage Scale Changes

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

Unions Represented	% Increase (a)	Effective Date(s)	Estimated Annual Financial Impact (b)
IBEW 57 Generation (UT, ID & WY)	2.81%	1/26/2009	$ 1,072,019
IBEW 57 Power Delivery (UT, ID & WY)	2.81%	1/26/2009	2,267,014
Total			$ 3,339,033

(a) This percentage increase represents the increase in wages for all effective dates during the calendar year as compared to the wage scale of the prior effective period.

(b) The estimated annual impact is based on the time period from the effective date of the increase to the end of the calendar year. Some amounts may be reimbursed by joint owners.

ITEM 9.

Legal Proceedings

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, penalties and other costs in substantial amounts and are described below.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp that operates a reactive and refractory metals manufacturing facility in Millersburg, Oregon, filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon, granted Wah Chang's motion and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence of alleged market manipulation during the energy crisis. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief.

In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon, asserting that the special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In August 2002, the Circuit Court for Linn County, Oregon, granted PacifiCorp's motion for summary judgment dismissing Wah Chang's complaint. In February 2004, the Circuit Court for Linn County, Oregon, granted Wah Chang's motion to reopen the case to present additional evidence of alleged market manipulation. In December 2007, Wah Chang filed a second amended complaint seeking recovery of a portion of the costs paid under the special tariff based on various theories of legal relief, including partial rescission, unjust enrichment, and breach of duty of good faith and fair dealing. In August 2009, the Circuit Court for Linn County, Oregon, granted Wah Chang's request to file a third amended complaint containing a claim for punitive damages. In December 2009, PacifiCorp's motion for summary judgment based on the OPUC's September 2009 order was denied by the Circuit Court for Linn County, Oregon. The trial date has been stayed until 2011. Wah Chang is seeking $37 million (less the amount Wah Chang would have paid for electricity absent the special tariff) in compensatory damages and $200 million in punitive damages. PacifiCorp intends to vigorously defend these claims and believes that the outcome of these proceedings will not have a material impact on its financial results.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal 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 that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the United States Environmental Protection Agency (the "EPA") for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's financial results.

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 was 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 generating facility. USA Power's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims. USA Power seeks $250 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. After considering various motions for summary judgment, the court ruled in October 2007 in favor of PacifiCorp on all counts and dismissed the plaintiffs' claims in their entirety. In February 2008, the plaintiffs filed a petition requesting consideration of their appeal by the Utah Supreme Court. The plaintiffs' request was granted and they filed a brief in November 2008 with the Utah Supreme Court. In January 2009, PacifiCorp filed its reply brief. PacifiCorp believes that its defenses that prevailed in the trial court will prevail on appeal. Furthermore, PacifiCorp expects that the outcome of any appeal will not have a material impact on its financial results.

ITEM 10.

Officer, Director & Security Holder Transactions

None.

ITEM 11.

(Reserved)

ITEM 12.

General Regulation

PacifiCorp is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and ability to recover costs.

Certain regulatory matters are subject to uncertainties that require the use of estimates on the financial statements, particularly that related to Oregon Senate Bill 408 ("SB 408"). Refer to Note 5 of Notes to Financial Statements in this Form No. 1 for further discussion.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Energy Policy Act and other federal statutes. The FERC regulates rates for interstate sales of electricity in wholesale markets; transmission of electric power, including pricing and expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric projects. The FERC also has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. PacifiCorp has implemented programs that facilitate compliance with the FERC regulations described below, including having instituted compliance monitoring procedures.

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's rates charged to wholesale customers for electricity and transmission capacity and related services. Most of PacifiCorp's wholesale electric sales and purchases take place under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The FERC conducts a triennial review of PacifiCorp's market-based pricing authority. PacifiCorp must demonstrate the lack of market power in order to charge market-based rates for sales of wholesale electricity and electric generation capacity in its balancing authority areas. PacifiCorp's next triennial filing is due in June 2010. Under the FERC's market-based rules, PacifiCorp must also file a notice of change in status when there is a significant change in the conditions that the FERC relied upon in granting market-based pricing authority. PacifiCorp is currently authorized to sell at market-based rates.

Transmission

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). In accordance with its OATT, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long- and short-term firm point-to-point transmission service (guaranteed service with fixed delivery and receipt points); and
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points).

These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its commercial and trading business, in accordance with the FERC Standards of Conduct.

For retail customers, transmission costs are not separated from, but rather are "bundled" with, generation and distribution costs in rates approved by state regulatory commissions.

FERC Order No. 890 – Preventing Undue Discrimination and Preference in Transmission Service

In February 2007, the FERC adopted a final rule in FERC Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service" ("Order No. 890") designed to strengthen the pro forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT 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 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. The FERC has issued rules through a set of subsequent orders clarifying Order No. 890. As a transmission provider with an OATT on file with the FERC, PacifiCorp is required to comply with the requirements of this rule. PacifiCorp made its first compliance filing amending its OATT in July 2007. The FERC has continued to issue rules through a set of subsequent orders clarifying Order No. 890. In response to these various orders, PacifiCorp has made several required compliance filings.

FERC Reliability Standards

The FERC has approved an extensive number of reliability standards developed by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council (the "WECC"), including critical infrastructure protection standards and regional standard variations. PacifiCorp must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC and the WECC. During 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards, and in November 2008, the FERC assumed control of certain aspects of the WECC's audit. In May 2009, PacifiCorp received a notice of alleged violation and proposed sanctions related to the portions of the WECC's 2007 audit that remained with the WECC. In July 2009, PacifiCorp reached a settlement in principle with the WECC, and a settlement agreement was executed in February 2010. The results of the settlement will not have a material impact on PacifiCorp's financial results. Refer to Note 13 of Notes to Financial Statements included in this Form No. 1 for additional information regarding certain aspects of the WECC's 2007 audit currently under the FERC's authority.

Hydroelectric Relicensing – Klamath River Hydroelectric Facilities

PacifiCorp's Klamath hydroelectric system is the only hydroelectric generating facility for which PacifiCorp is engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 13 of Notes to Financial Statements in this Form No. 1 for an update regarding hydroelectric relicensing for PacifiCorp's Klamath hydroelectric system.

Hydroelectric Decommissioning – Condit Hydroelectric Facility – White Salmon River, Washington

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility 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 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal would not begin until October 2008, with a total cost to decommission not to exceed $21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp is in the process of acquiring all necessary permits within the terms and conditions of the amended settlement agreement. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin no earlier than October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. In January 2009, the study work was completed and the results were provided to the United States Army Corps of Engineers and the Washington Department of Ecology. In January 2010, the Washington Department of Ecology released the Final Second Supplemental Environmental Impact Statement which formally considered this additional information. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process within the second quarter of 2010. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

Northwest Refund Case

For a discussion of the Northwest Refund case, refer to Note 13 of Notes to Financial Statements in this Form No. 1.

United States Mine Safety

PacifiCorp's mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA"), which administers federal mine safety and health laws, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. PacifiCorp is required to develop a written emergency response plan specific to each underground mine it operates. These plans must be reviewed by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay the penalties or fines.

State Regulation

PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. Historically, state utility commissions have established rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. A utility's cost of service generally reflects its allowed operating expenses, including energy costs, operation and maintenance expense, depreciation expense and income and other tax expense, reduced by wholesale electric sales and other revenue. State utility commissions may adjust rates pursuant to a review of (a) the utility's revenue and expenses during a defined test period and (b) the utility's level of investment. State utility commissions typically have the authority to review and change rates on their own initiative. States may also initiate reviews at the request of a utility, utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

In addition to recovery through general rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

State Regulator	Base Rate Test Period	Adjustment Mechanism
Utah Public Service Commission	Forecasted or historical with known and measurable changes (1)	PacifiCorp has requested approval of an energy cost adjustment mechanism ("ECAM") to recover the difference between base net power costs set during a general rate case and actual net power costs. A recovery mechanism is available for a single capital investment project that in total exceeds 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
Oregon Public Utility Commission	Forecasted	Annual transition adjustment mechanism ("TAM"), a mechanism for annual rate adjustments for forecasted net variable power costs; no true-up to actual net variable power costs. Renewable adjustment clause ("RAC") to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates. Annual true-up of taxes authorized to be collected in rates compared to taxes paid by PacifiCorp, as defined by Oregon statute and administrative rules under SB 408.
Wyoming Public Service Commission (the "WPSC")	Forecasted or historical with known and measurable changes (1)	Power cost adjustment mechanism ("PCAM") based on forecasted net power costs, later trued-up to actual net power costs, subject to dead bands and customer sharing. PacifiCorp has requested approval of a new ECAM to replace the existing PCAM, which is set to expire in November 2010.
Washington Utilities and Transportation Commission	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources that qualify under the state's emissions performance standard and are not reflected in general rates.
Idaho Public Utilities Commission	Historical with known and measurable changes	ECAM to recover the difference between base net power costs set during a general rate case and actual net power costs, subject to customer sharing and other adjustments.
California Public Utilities Commission (the "CPUC")	Forecasted	Post test-year adjustment mechanism for major capital additions ("PTAM – capital additions"), a mechanism that allows for rate adjustments outside of the context of a traditional rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service. Energy cost adjustment clause ("ECAC") that allows for an annual update to actual and forecasted net variable power costs. Post test-year adjustment mechanism for attrition ("PTAM – attrition"), a mechanism that allows for an annual adjustment to costs other than net variable power costs.

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments and forecasted test periods. The WPSC has not issued a final ruling on its preference between historical or forecasted test periods.

PacifiCorp's energy efficiency program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs, as approved by the respective state utility commission.

Utah

In July 2008, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million prior to any consideration of the UPSC's order in the 2007 general rate case. In September 2008, PacifiCorp filed supplemental testimony that reflected then-current revenues and other adjustments based on the August 2008 order in the 2007 general rate case. The supplemental filing reduced PacifiCorp's request to $115 million. In October 2008, the UPSC issued an order changing the test period from the twelve months ending June 2009 using end-of-period rate base to the forecast calendar year 2009 using average rate base. In December 2008, PacifiCorp updated its filing to reflect the change in the test period. The updated filing proposed an increase of $116 million. In March 2009, a settlement agreement was filed with the UPSC resolving all remaining revenue requirement issues, resulting in parties agreeing, among other settlement terms, on an annual increase of $45 million, or an average price increase of 3%, effective May 8, 2009. In April 2009, the UPSC issued its final order approving the revenue requirement settlement agreement.

In March 2009, Utah's governor signed Senate Bill 75 that provides additional regulatory tools for the UPSC to use in the ratemaking process. The additional tools provided in the legislation allow for single item cost recovery of major capital investments outside of the general rate case process and allow for, but do not require, the use of an energy balancing account.

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommends that the UPSC adopt the ECAM to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. The UPSC has separated the application into two phases to first address whether the mechanism is in the public interest, and then if it is found to be in the public interest, to determine the type of mechanism that should be implemented. Hearings on the public interest phase were completed in January 2010. In February 2010, the UPSC issued an order to proceed to the second phase to address design considerations in the development of an ECAM. Additionally, in February 2010, PacifiCorp filed an application with the UPSC seeking approval to defer the difference between the net power costs allowed by the UPSC's final order in PacifiCorp's 2009 general rate case and the actual net power costs incurred. If approved, the filing would establish a deferred cost balance to be considered for collection through any potential mechanism established in the second phase of the ECAM proceeding.

In February 2010, an application was filed with the UPSC by the Utah Association of Energy Users requesting an order requiring PacifiCorp to defer for later ratemaking treatment all revenues associated with sales of renewable energy credits in excess of the level included in Utah rates. If approved, Utah's share of any renewable energy credit sales above $18.5 million annually would be subject to consideration in a future proceeding.

In June 2009, PacifiCorp filed a general rate case with the UPSC for an increase of $67 million, or an average price increase of 5%. The forecasted test period is the twelve months ending June 30, 2010. In November 2009, as part of its rebuttal and surrebuttal filings, PacifiCorp reduced its rate increase request to $53 million. The UPSC issued its order February 18, 2010, approving a price increase of $32 million, or an average price increase of 2%.

In June 2009, PacifiCorp filed with the UPSC to increase its demand-side management ("DSM") cost recovery mechanism in Utah from an average of 2% of a customer's eligible monthly charges to 6%. In August 2009, a settlement agreement was filed with the UPSC requesting the DSM cost recovery mechanism be adjusted to 5%, representing an estimated annual increase of $35 million, which would enable PacifiCorp to continue to fund ongoing DSM programs and to recover previously incurred DSM expenditures. The UPSC approved the settlement agreement in August 2009, and the 5% DSM cost recovery mechanism became effective September 1, 2009.

In February 2010, PacifiCorp filed an alternative cost recovery application with the UPSC requesting recovery of $34 million associated with two major construction projects that are expected to be completed and in-service by June 2010. The mechanism provides for a ruling from the UPSC within 150 days of the application. In March 2010, PacifiCorp updated its cost recovery application, reducing the net revenue requirement impact of the two major construction projects to $33 million.

Oregon

In March 2009, PacifiCorp made the initial filing for the annual TAM with the OPUC for an annual increase of $21 million to recover the anticipated net power costs for the year beginning January 1, 2010. In August 2009, PacifiCorp filed a revision to its anticipated net power costs for the TAM, reflecting a slight decrease in the overall request to $20 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC reducing the requested increase to $4 million, or an average price increase of less than 1%. In October 2009, the OPUC issued an order approving the settlement stipulation. In November 2009, PacifiCorp filed the final net power costs update for the TAM, based on the latest forward price curve. The final update shows a net power costs increase of $4 million, or an average price increase of less than 1%. The effective date for the TAM was January 1, 2010.

In April 2009, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $92 million. In August 2009, the requested annual increase was reduced to $83 million. In September 2009, PacifiCorp filed a settlement stipulation with the OPUC further reducing the proposed annual increase to $42 million, or an average price increase of 4%. The stipulation agreement also includes three tariff riders to collect an additional $8 million over a three-year period associated with various cost initiatives. In January 2010, the OPUC approved the stipulation effective February 2, 2010.

In February 2010, PacifiCorp made the initial filing for the annual TAM with the OPUC for an annual increase of $69 million to recover the anticipated net power costs forecasted for calendar year 2011. The rates in the TAM filing will be effective January 1, 2011 and are subject to updates throughout the proceeding.

In March 2010, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $131 million, or an average price increase of 13%. If approved by the OPUC, the rates will be effective January 1, 2011.

For a discussion of SB 408, refer to Note 5 of Notes to Financial Statements in this Form No. 1.

Wyoming

In July 2008, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $34 million with an effective date of May 24, 2009. Power costs were excluded from the filing and were addressed separately in PacifiCorp's annual PCAM application filed in February 2009. In October 2008, the general rate case request was reduced by $5 million, to $29 million, to reflect a change in the in-service date of the High Plains wind-powered generating facility. In March 2009, a settlement agreement was filed with the WPSC revising the requested increase in Wyoming rates to $18 million annually beginning May 24, 2009, for an average overall price increase of 4%. Following public hearings in March 2009, the WPSC issued a final order approving the stipulation agreement in May 2009.

In February 2009, PacifiCorp filed its annual PCAM application with the WPSC. The PCAM application requested recovery of the difference between actual net power costs and the amount included in base rates, subject to certain limitations, for the period December 1, 2007 through November 30, 2008, and established for the first time an adjustment for the difference between forecasted net power costs and the amount included in base rates for the period December 1, 2008 through November 30, 2009. In the 2009 PCAM application, PacifiCorp requested a $2 million reduction to the current annual surcharge rate based on the results for the twelve-month period ended November 30, 2008, as well as a $16 million increase to the annual surcharge rate for the forecasted twelve-month period ending November 30, 2009, resulting in a net increase to the annual surcharge rate of $14 million on a combined basis. In March 2009, the WPSC approved PacifiCorp's motion to implement an interim rate increase of $7 million, effective April 1, 2009 consistent with the interim PCAM increase agreed to in the 2008 general rate case settlement agreement. In July 2009, a stipulation agreement was signed by the major participants in the case requesting that the April 2009 interim rate increase become the permanent rate for the entire amortization period through March 31, 2010, effectively reducing the net increase of $14 million sought in the application to $7 million, or an average price increase of 1%. In August 2009, the WPSC held a public hearing to consider the stipulation agreement, and after considering the evidence, the WPSC issued a bench decision approving the stipulation effective September 1, 2009.

In October 2009, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $71 million. Power costs are included in the general rate case, reflecting increased coal costs and the expiration of low cost long-term power purchase contracts. The application is based on a test period ending December 31, 2010. Two regulatory policy issues related to the tax treatment of equity AFUDC and the accounting for coal stripping costs are included in the case, which if approved by the WPSC, would reduce the requested rate increase by $9 million to an overall requested increase of $62 million, or an average price increase of 12%. The application requests a rate effective date of August 1, 2010. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to an overall rate increase of $36 million, or an average price increase of 7%, to be implemented in two phases. If the stipulation is approved by the WPSC, the first phase, consisting of a $26 million increase, will be effective July 1, 2010 and the second phase, consisting of the remaining $10 million increase, will be effective February 1, 2011. The WPSC has scheduled public hearings for April 2010.

In January 2010, PacifiCorp filed its annual PCAM application with the WPSC requesting recovery of $8 million in deferred net power costs. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to reduce the requested recovery to $4 million with an effective date of April 1, 2010. The stipulation is subject to approval by the WPSC.

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM, which is set to expire in November 2010.

Washington

In February 2008, PacifiCorp filed a general rate case with the WUTC for an annual increase of $35 million. In August 2008, PacifiCorp filed with the WUTC an all-party settlement agreement in which the parties agreed to an overall rate increase of $20 million, or 9%. The settlement was approved by the WUTC in October 2008 with the new rates effective October 15, 2008. The increase is composed of an $18 million increase to base rates, as well as a $2 million annual surcharge for approximately three years related to recovery of higher power costs incurred in 2005 due to poor hydroelectric conditions. PacifiCorp agreed to drop the current proposal for a generation cost adjustment mechanism and further committed not to propose such a mechanism in the next general rate case.

In February 2009, PacifiCorp filed a general rate case with the WUTC for an annual increase of $39 million. The filing included a request to begin collection of a deferral for costs associated with the 520-MW Chehalis natural gas-fired generating facility prior to its inclusion in rate base beginning in January 2010. The associated costs are estimated at $15 million. PacifiCorp has proposed to recover these costs through an extension of its hydroelectric deferral mechanism, thereby not affecting current customer rates. In August 2009, PacifiCorp filed an all-party settlement agreement proposing an annual increase of $14 million, or an average price increase of 5%. In December 2009, the WUTC approved the all-party settlement agreement. The new rates became effective January 1, 2010.

Idaho

In September 2008, PacifiCorp filed a general rate case with the IPUC for an annual increase of $6 million. In February 2009, a settlement signed by PacifiCorp, the IPUC staff and intervening parties was filed with the IPUC resolving all issues in the 2008 general rate case. The agreement stipulated a $4 million increase, or an average price increase of 3%, for non-contract retail customers in Idaho. As part of the stipulation, intervening parties acknowledged that PacifiCorp's acquisition of the 520-MW Chehalis natural gas-fired generating facility was prudent and the investment should be included in PacifiCorp's revenue requirement, and that PacifiCorp had demonstrated that its DSM programs are prudent. The parties also agreed on a base level of net power costs for any future ECAM calculations. In April 2009, the IPUC issued an order approving the stipulation effective April 18, 2009.

In June 2009, an agreement was reached with parties to the ECAM docket allowing for the implementation of an ECAM to recover the difference between the base level of net power costs recovered in rates and actual costs incurred, subject to the calculation methodology of the mechanism. In September 2009, the IPUC issued an order approving the ECAM stipulation as filed with an effective date of July 1, 2009. In February 2010, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $2 million in deferred net power costs. In March 2010, the IPUC issued an order approving PacifiCorp's ECAM application for recovery of $2 million effective April 1, 2010.

California

In February 2009, PacifiCorp filed a PTAM – capital additions with the CPUC for major capital additions amounting to a rate increase of $1 million, or an average price increase of 2%. The filing included the addition of four major renewable resources: the 99-MW Seven Mile Hill, the 99-MW Glenrock, the 39-MW Glenrock III and the 99-MW Rolling Hills wind-powered generating facilities. The rates became effective March 19, 2009. In October 2009, PacifiCorp filed a PTAM – capital additions with the CPUC for major capital additions amounting to a rate increase of $1 million, or an average price increase of 1%. The filing included the addition of two major renewable resources: the 99-MW High Plains and the 28-MW McFadden Ridge I wind-powered generating facilities. The rates became effective November 21, 2009.

In February 2009, PacifiCorp filed an application to extend its PTAM – attrition (an adjustment for inflation) through 2010 and to delay filing its next general rate case by one year. The application was approved by the CPUC in April 2009. In October 2009, PacifiCorp filed its annual PTAM – attrition with the CPUC. The filing requested an increase of $1 million, or an average price increase of 1%. The rates became effective January 1, 2010.

In July 2009, PacifiCorp made its annual filing under the ECAC requesting a rate reduction of $5 million, or an average price decrease of 5%, due to a decrease in net power costs. In December 2009, the CPUC approved the ECAC with an effective date of January 1, 2010.

In November 2009, PacifiCorp filed a general rate case with the CPUC requesting an annual increase of $8 million, or an average price increase of 10%. If approved by the CPUC, the rates will be effective January 1, 2011.

In March 2010, PacifiCorp filed an application with the CPUC for authorization to offer PacifiCorp's California customers a solar incentive program that would pay incentives to customers for installing solar photovoltaic equipment at their homes or businesses. The program would be funded through a new surcharge designed to collect the proposed annual program budget of approximately $1 million, or an average price increase of 1%. Funds collected through the surcharge would only be used to pay customer incentives and cover the administrative costs associated with the program. PacifiCorp has requested an effective date of August 2, 2010.

In March 2010, PacifiCorp filed an advice filing with the CPUC that would allow PacifiCorp to complete the transition of certain Klamath irrigation customers from contract rates to full tariff rates as agreed to as part of the 2005 California general rate case. If approved by the CPUC, the change will result in an annual rate increase of $1 million effective April 17, 2010.

Environmental Laws and Regulation

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Clean Air Standards

The Clean Air Act is a federal law, administered by the EPA, that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in State Implementation Plans ("SIPs"). SIPs, which are a collection of regulations, programs and policies to be followed, are subject to public hearings, must be approved by the EPA and vary by state. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs, which most directly affect PacifiCorp's operations, are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxide ("NO_x"), particulate matter, ozone and sulfur dioxide ("SO_2"), considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present.

On December 14, 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. This designation has the potential to impact PacifiCorp's Little Mountain, Lake Side and Gadsby facilities, depending on the requirements to be established in the Utah SIP. The impact on the PacifiCorp facilities is not anticipated to be significant.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arises out of legal challenges claiming that the March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposes a standard between 60 and 70 parts per billion. The EPA expects to issue final standards later in 2010 with SIPs submitted in 2013.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. State attainment designations must be submitted to the EPA by January 1, 2011 and the EPA must finalize the designations by January 1, 2012.

In November 2009, the EPA proposed a new national ambient air quality standard for SO_2 to a level of between 50 and 100 parts per billion measured over one hour. The existing primary standards for SO_2 are 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year. The EPA is under a consent decree to take final action on the proposed standards by June 2010.

If the stricter standards are implemented, the number of counties designated as nonattainment areas may increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until the EPA issues the final rules and any legal challenges are settled, the impacts on PacifiCorp cannot be determined.

Clean Air Mercury Rule

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fired generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. The EPA plans to propose a new rule that will require coal-fired generating facilities to reduce mercury emissions by utilizing a mandated "Maximum Achievable Control Technology" rather than a cap-and-trade system. Under a consent decree, the EPA must issue a proposed rule to regulate mercury emission by March 2011 and a final rule no later than November 2011. If adopted, the new rule will likely result in incremental costs to install and maintain mercury emissions control equipment at each of PacifiCorp's coal-fired generating facilities and would increase the cost of providing service to customers. Until the EPA issues the proposed and final rules, the impacts on PacifiCorp cannot be determined.

Clean Air Interstate Rule

The EPA promulgated the Clean Air Interstate Rule ("CAIR") in March 2005 to reduce emissions of NO_X and SO_2, precursors of ozone and particulate matter, from down-wind sources. The CAIR required states in the eastern United States to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emission reductions, or both. The CAIR created separate trading programs for NO_X and SO_2 emission credits. The NO_X and SO_2 emissions reductions were planned to be accomplished in two phases, in 2009-2010 and 2015.

In July 2008, a three-judge panel of the D.C. Circuit issued a unanimous decision vacating the CAIR. In December 2008, the D.C. Circuit issued an opinion remanding, without vacating, the CAIR back to the EPA to conduct proceedings to fix the flaws in CAIR consistent with the D.C. Circuit's July 2008 ruling. The D.C. Circuit did not impose a schedule for completion on the EPA in its ruling, and the EPA informed the D.C. Circuit that development and finalization of a replacement rule could take approximately two years.

PacifiCorp's generating facilities are not subject to the CAIR. The impact of the replacement rule cannot be determined until the EPA issues its final rule. It is possible that the existing CAIR may be replaced with more stringent requirements to reduce SO_2 and NO_X emissions and that these requirements could be extended to the western United States through regulation or legislation such as the Clean Air Act Amendments of 2010, introduced in February 2010 by Senators Tom Carper and Lamar Alexander. However, the provisions are not anticipated to have a material impact on PacifiCorp.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's generating facilities meet the threshold applicability criteria under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emission controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Wyoming has not yet submitted its SIP. Wyoming issued best available retrofit technology permits to PacifiCorp on December 31, 2009, requiring PacifiCorp to implement emission control projects that are consistent with the planned emission reduction projects at PacifiCorp's Wyoming generating facilities. PacifiCorp has appealed certain provisions of the Naughton and Jim Bridger generating facilities' permits. Utah submitted its SIP and suggested that the emission reduction projects planned by PacifiCorp are sufficient to meet its initial emission reduction requirements. In January 2009, the EPA made a finding that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic regional haze program requirements. As a result, Wyoming has two years from January 2009 to file and obtain the EPA's approval of a SIP that meets all of the regional haze program requirements or the state will be subject to a federal implementation plan administered by the EPA. PacifiCorp believes that its planned emission reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been submitted and approved or that the timing of installation of planned controls could change.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp responded to requests for information relating to capital projects at its generating facilities. PacifiCorp has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. Final resolution has not been achieved. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls and incur additional costs and penalties in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts, and the recent change in administration, create risk and uncertainty for entities when seeking permits for new projects and installing emission controls at existing facilities under NSR requirements. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

Climate Change

The increased global attention to climate change has resulted in significant measures being proposed at the federal level to regulate greenhouse gas ("GHG") emissions. The United States Congress and federal policy makers, with President Obama's support, are considering comprehensive climate change legislation such as the American Clean Energy and Security Act of 2009 ("Waxman-Markey bill"), which includes a market-based cap-and-trade program that is intended to reduce GHG emissions 83% below 2005 levels by 2050. In December 2009, the EPA published its findings that GHG emissions threaten the public health and welfare, and it is pursuing regulation of GHG emissions under the Clean Air Act. In early 2010, legislation and resolutions were introduced in the United States Congress that would disapprove the findings submitted by the EPA and clarify that the United States Congress did not intend to regulate GHG emissions under the Clean Air Act. To date, two bills, one by Representative Early Pomeroy and one by Representatives Ike Skelton, Collin Peterson and Jo Ann Emerson, have been introduced in the United States House of Representatives seeking to amend the Clean Air Act to preclude the EPA from regulating GHG emissions under the Clean Air Act. In addition, a disapproval resolution has been introduced by Senator Lisa Murkowski and others in the United States Senate disapproving the EPA's GHG endangerment finding. Litigation has also been filed in the D.C. Circuit challenging the EPA's GHG endangerment finding, including an action by twelve members of the United States House of Representatives. An additional 15 lawsuits have been filed by states, various industry groups, and others, petitioning the court for review of the endangerment finding.

PacifiCorp supports the implementation of reasonable emissions caps, but opposes the trading mechanism as imposing additional costs that do not result in decreased emissions. PacifiCorp also believes that any law or regulation should provide a reasonable transition period to allow the phase in of low-carbon generating technologies that will achieve sustainable and cost-effective GHG emissions reduction benefits.

While the debate continues at the federal and international level over the direction of climate change policy, several states have developed or are developing state-specific laws or regional legislative initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing litigation under existing laws.

PacifiCorp voluntarily reports its GHG emissions to the California Climate Action Registry and The Climate Registry. In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG ("GHG Reporting") beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions are required to submit annual reports to the EPA. PacifiCorp is subject to this requirement and will submit its first report by March 31, 2011.

PacifiCorp is committed to operating in an environmentally responsible manner. Examples of PacifiCorp's significant investments in programs and facilities that will mitigate its GHG emissions include:

- PacifiCorp is the second largest owner of wind-powered generation capacity in the United States among rate-regulated utilities. Over the last three years, PacifiCorp has added 787 MW of owned wind generation capacity at a total cost of $1.6 billion to its portfolio of generating assets. PacifiCorp currently owns 921 MW of wind-powered generation capacity, excluding its 111-MW Dunlap Ranch I wind-powered generating facility that is currently under construction. Additionally, PacifiCorp has purchase power agreements with 705 MW of wind-powered generation capacity. Other renewable resources owned or contracted total an incremental capacity of 105 MW.
- PacifiCorp owns 1,158 MW of hydroelectric generation capacity.
- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines at a cost exceeding $6 billion. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States.
- PacifiCorp has offered customers a comprehensive set of DSM programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.

The impact of pending federal, regional, state and international accords, legislation, regulation, or judicial proceedings related to climate change cannot be quantified in any meaningful range at this time. New laws, regulations or rules limiting GHG emissions could have a material adverse impact on PacifiCorp, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fired generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emission control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new laws and regulations may impact PacifiCorp include:

- Additional costs may be incurred to purchase required emission allowances under the proposed market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and unit outputs may be lower; and
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a financial risk.

PacifiCorp expects it will be allowed to recover prudently incurred costs to comply with climate change requirements.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence PacifiCorp's existing and future electricity generation portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

International Accords

The December 2009 Copenhagen Accord called on officials from developed nations to voluntarily commit to quantified economy-wide emissions targets for 2020 by January 31, 2010. In January 2010, the Obama administration formally declared its desire to be associated with the Copenhagen Accord, informing the United Nations Framework Convention on Climate Change of the goal of reducing United States GHG emissions approximately 17% from 2005 levels by 2020, contingent upon the enactment of United States energy and climate change legislation. The United States' goal is not binding or enforceable absent from further action by the United States Congress to enact climate change legislation.

Federal Legislation

In June 2009, the United States House of Representatives passed the Waxman-Markey bill. In addition to a federal renewable portfolio standard, which would require utilities to obtain a portion of their energy from certain qualifying renewable sources and energy efficiency measures, the bill requires a reduction in GHG emissions beginning in 2012, with emission reduction targets of 3% below 2005 levels by 2012; 17% below 2005 levels by 2020; 42% below 2005 levels by 2030; and 83% below 2005 levels by 2050 under a cap-and-trade program. In September 2009, a similar bill was introduced in the United States Senate by Senators Barbara Boxer and John Kerry, which would require a reduction in GHG emissions beginning in 2012 with emission reduction targets consistent with the Waxman-Markey bill, with the exception of the 2020 target, which requires 20% reductions below 2005 levels.

Greenhouse Gas Tailoring Rule

The EPA published a proposed GHG "tailoring rule" in October 2009 that would require sources of GHG emissions in excess of 25,000 tons of carbon dioxide ("CO_2") equivalent to conduct a determination of best available control technology under the PSD provisions for new and modified sources. In addition, the proposal would require sources of CO_2 equivalent emissions of 25,000 tons or more to obtain a Title V operating permit or incorporate GHG emissions into existing sources' Title V permits when they are renewed. The EPA is currently working to finalize the rules with an anticipated effective date for stationary sources beginning in 2011. Until final rules are issued, PacifiCorp cannot determine the impact on its facilities. Several organizations have indicated that they intend to challenge the EPA's final GHG tailoring rule.

Regional and State Activities

Several states have developed state-specific laws or regional legislative initiatives to report or mitigate GHG emissions that are expected to impact PacifiCorp, including:

- The Western Climate Initiative, a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting GHG emissions in 2011 for emissions that occur in 2010. The first phase of the cap-and-trade program will begin on January 1, 2012.
- An executive order signed by California's governor in June 2005 would reduce GHG emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80% below 1990 levels by 2050. In addition, California has adopted legislation that imposes a GHG emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emission levels of a state-of-the-art combined-cycle natural gas-fired generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020. An effort is currently underway to gather a sufficient number of signatures to institute a California ballot initiative, referenced as the "California Jobs Initiative", which seeks to place before the voters a requirement to suspend GHG regulations promulgated under California's GHG emission reduction legislation (Assembly Bill 32) until California's unemployment rate is lowered to 5.5%.
- Over the past three years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electrical generating resources. Under the laws in all three states, the emissions performance standards provide that emissions must not exceed 1,100 lbs of CO_2 per megawatt hour ("MWh"). These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.

Greenhouse Gas Litigation

PacifiCorp closely monitors ongoing environmental litigation. Many of the pending cases described below relate to lawsuits against industry that attempt to link GHG emissions to public or private harm. PacifiCorp believes the cases are without merit, despite recent decisions where United States Court of Appeals reversed district court rulings dismissing the cases in 2009. The lower courts initially

refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. Nevertheless, an adverse ruling in any of these cases would likely result in increased regulation of GHG emitters, including PacifiCorp's generating facilities, and financial uncertainty.

In September 2009, the United States Court of Appeals for the Second Circuit (the "Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of CO_2. The United States District Court for the Southern District of New York (the "Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a political question that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits.

In October 2009, a three judge panel in the United States Court of Appeals for the Fifth Circuit (the "Fifth Circuit") issued its opinion in the case of *Ned Comer, et al. v. Murphy Oil USA, et al.*, a putative class action lawsuit against insurance, oil, coal and chemical companies, based on claims that the defendants' GHG emissions contributed to global warming that in turn caused a rise in sea levels and added to the ferocity of Hurricane Katrina, which combined to damage the plaintiff's private property, as well as public property. In 2007, the United States District Court for the Southern District of Mississippi (the "Southern District of Mississippi") dismissed the case based on the lack of standing and further held that the claims were barred by the political question doctrine. The Fifth Circuit reversed the lower court decision and held that the plaintiffs had standing to assert their public and private nuisance, trespass and negligence claims, and concluded that the claims did not present a political question. The case was remanded to the Southern District of Mississippi for further proceedings with the court noting that it had not determined, and would leave to the lower court to analyze, whether the alleged chain of causation satisfies the proximate cause requirement under Mississippi state common law.

In October 2009, the United States District Court for the Northern District of California (the "Northern District of California") granted the defendants' motions to dismiss in the case of *Native Village of Kivalina v. ExxonMobil Corporation, et al.* The plaintiffs filed their complaint in February 2008, asserting claims against 24 defendants, including electric generating companies, oil companies and a coal company, for public nuisance under state and federal common law based on the defendants' GHG emissions. MEHC was a named defendant in the Kivalina case. The Northern District of California dismissed all of the plaintiffs' federal claims, holding that the court lacked subject matter jurisdiction to hear the claims under the political question doctrine, and that the plaintiffs lacked standing to bring their claims. The Northern District of California declined to hear the state law claims and the case was dismissed with prejudice to their future presentation in an appropriate state court.

Several lawsuits have also been filed against governmental agencies, most notably *Massachusetts v. EPA*. In April 2007, in Massachusetts v. EPA, the United States Supreme Court found that GHG are air pollutants and are covered by the Clean Air Act. The United States Supreme Court decision resulted from a petition for rulemaking filed by more than a dozen environmental, renewable energy and other organizations. The court held that the EPA must determine whether or not GHG emissions contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In December 2009, the EPA determined that GHG emissions in the atmosphere threaten the public health and welfare of current and future generations and is pursuing regulation of GHG emissions under the Clean Air Act. Unless superseded by congressional action, the EPA ruling is likely to lead to stricter emission limits.

Renewable Portfolio Standards

The renewable portfolio standards ("RPS") described below could significantly impact PacifiCorp's financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state to state. Each state's RPS requires some form of compliance reporting and PacifiCorp can be subject to penalties in the event of noncompliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative.

In June 2007, the Oregon Renewable Energy Act ("OREA") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the OREA, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

California law requires electric utilities to increase their procurement of renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") received further guidance from the CPUC on the treatment of SMJUs in the California RPS program. In August 2008, concurrent with its annual RPS compliance filing, PacifiCorp, joined by another SMJU, filed a Joint Motion for Review of the decision, including banking of RPS procurement made while it awaited further guidance from the CPUC on the treatment of SMJUs during the 2004-2006 period. In May 2009, the CPUC denied the Joint Motion for Review.

In September 2009, California's governor issued Executive Order S-21-09 requiring the California Air Resources Board to adopt a regulation consistent with a 33% renewable electricity energy target established in Executive Order S-14-08 by July 31, 2010 that will encourage the creation and use of renewable energy sources and build on the existing RPS program.

In March 2008, Utah's governor signed Utah Senate Bill 202. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as the Second Circuit takes action or further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston Plant, which has water cooling towers, exceeds the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant. PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of coal combustion storage and disposal. The EPA is currently considering the regulation of coal combustion byproducts under the Resource Conservation and Recovery Act and a proposed rule addressing these materials is imminent. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by additional regulation, particularly if the materials are regulated as hazardous waste under Subtitle C of the Resource Conservation Act, and could pose significant additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The impact of any new regulations on coal combustion byproducts cannot be determined at this time.

Other

Other laws, regulations and agencies to which PacifiCorp is subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Refer to Note 13 of Notes to Financial Statements in this Form No. 1 for additional information regarding environmental contingencies.
- The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. Refer to Note 10 of Notes to Financial Statements in this Form No. 1 for additional information regarding mine reclamation obligations.
- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 13 of Notes to Financial Statements in this Form No.1 for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric facilities.

Future Generation and Conservation

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") 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 IRP 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, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis, and for four of its six state jurisdictions, receives a formal notification as to whether the IRP meets the commission's IRP standards and guidelines. In May 2009, PacifiCorp filed its 2008 IRP with each of its state commissions. During 2009, PacifiCorp received orders from the WUTC and the IPUC acknowledging that the 2008 IRP met their applicable standards and guidelines. During 2010, the OPUC and the UPSC issued orders acknowledging the 2008 IRP.

Requests for Proposals

PacifiCorp has issued a series of separate Requests for Proposals ("RFPs"), each of which focuses on a specific category of resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve a balance of load requirements and resources. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the UPSC, the OPUC and the WUTC prior to issuance to the market. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

In August 2009, under PacifiCorp's 2008R-1 renewable resources RFP (approved by the OPUC in September 2008), PacifiCorp executed a power purchase agreement to purchase the entire output of the proposed 200-MW Top of the World wind-powered generating facility located in Wyoming. The generation of the energy and associated renewable energy credits under this agreement are expected to commence by December 2010 and continue for a period of 20 years. PacifiCorp's 2009R renewable resources RFP (approved by the OPUC with modification in July 2009) seeks additional cost-effective renewable generation projects with no single resource greater than 300 MW, combined total resources of no more than 400 MW and on-line dates no later than December 31, 2012. As a result of the 2009R renewable resources RFP, PacifiCorp's 111-MW Dunlap Ranch I wind-powered generating facility located in Wyoming was selected and construction has commenced. Negotiations were also initiated with the remaining final shortlist bidder under the 2009R renewable resources RFP.

In October 2009, PacifiCorp filed a request for approval with the UPSC to re-issue the All Source RFP, which was previously suspended in April 2009. In October 2009 and November 2009, respectively, the UPSC and the OPUC approved resumption of the All Source RFP. The All Source RFP seeks up to 1,500 MW on a system wide basis from projects with in-service dates from 2014 through 2016. In December 2009, the All Source RFP was issued to the market. Proposals have been received under the All Source RFP and evaluations are currently underway.

Demand-side Management

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs, such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by retail electric customers. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 342 MW of load reduction when needed. Recovery for the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. In 2009, $106 million was expended on the DSM programs in PacifiCorp's six-state service area, resulting in an estimated 457,000 MWh of first-year energy savings and 441 MW of peak load management. Total demand-side load available for control in 2009, including both load management from the large industrial curtailment contracts and DSM programs, was 783 MW.

Credit Ratings

PacifiCorp's senior secured and senior unsecured credit ratings are as follows:

	Fitch	Moody's	Standard & Poor's
Senior secured debt	A-	A2	A
Senior unsecured debt	BBB+	Baa1	A-
Outlook	Stable	Stable	Stable

Debt and preferred securities of PacifiCorp are rated by the credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

PacifiCorp has no credit rating-downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under the applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In accordance with industry practice, certain agreements, including derivative contracts, contain provisions that require PacifiCorp to maintain specific credit ratings on its unsecured debt from one or more of the major credit rating agencies. These agreements, including derivative contracts, may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of December 31, 2009, PacifiCorp would have been required to post $310 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings or other factors. Refer to Note 7 of Notes to Financial Statements included in this Form No. 1 for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

ITEM 13.

Officer & Director Changes

On January 13, 2010, A. Robert Lasich accepted the position of Vice President and General Counsel, Procurement for MEHC, and accordingly resigned as President of PacifiCorp Energy, a business unit of PacifiCorp, and as director of PacifiCorp, both effective February 1, 2010.

On January 13, 2010, Micheal G. Dunn was elected President of PacifiCorp Energy and director of PacifiCorp, both effective February 1, 2010. Mr. Dunn, 44, previously served as President of Kern River Gas Transmission Company ("Kern River") since June 2007. Prior to that, Mr. Dunn served as Vice President of Operations, Information Technology and Engineering at Kern River. Kern River is an indirect subsidiary of MEHC.

ITEM 14.

Not applicable.

Deloitte.

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INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the balance sheet — regulatory basis of PacifiCorp (the "Company") as of December 31, 2009, and the related statements of income — regulatory basis; retained earnings — regulatory basis; and cash flows — regulatory basis, for the year ended December 31, 2009, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

As discussed in Note 2, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2009, and the results of its operations and its cash flows for the year ended December 31, 2009, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

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

Deloitte & Touche LLP

March 1, 2010

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	19,881,830,192	18,462,953,925
3	Construction Work in Progress (107)	200-201	1,799,367,394	1,208,785,536
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		21,681,197,586	19,671,739,461
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,199,824,404	6,848,927,351
6	Net Utility Plant (Enter Total of line 4 less 5)		14,481,373,182	12,822,812,110
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)		14,481,373,182	12,822,812,110
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		11,538,314	9,497,834
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,421,418	1,455,833
20	Investments in Associated Companies (123)		11,220,813	9,031,958
21	Investment in Subsidiary Companies (123.1)	224-225	184,718,167	171,510,195
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)		84,336,862	85,601,343
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		6,945,599	8,081,370
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		42,909,107	86,579,549
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		340,247,444	368,846,416
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,238,848	15,725,712
36	Special Deposits (132-134)		610,443	2,048,982
37	Working Fund (135)		1,920	2,020
38	Temporary Cash Investments (136)		81,769,678	3,937,516
39	Notes Receivable (141)		208,656	270,949
40	Customer Accounts Receivable (142)		361,520,728	346,007,077
41	Other Accounts Receivable (143)		32,319,952	43,610,380
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		7,052,112	8,679,145
43	Notes Receivable from Associated Companies (145)		4,748,292	20,797,545
44	Accounts Receivable from Assoc. Companies (146)		14,254,320	8,447,228
45	Fuel Stock (151)	227	170,930,143	136,802,882
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	178,147,022	170,075,369
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	04/14/2010	End of 2009/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)		298,656,263	84,769,212
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		8,788	28,102
60	Rents Receivable (172)		2,772,053	2,172,050
61	Accrued Utility Revenues (173)		213,989,000	210,896,000
62	Miscellaneous Current and Accrued Assets (174)		0	8,854,407
63	Derivative Instrument Assets (175)		151,143,601	260,256,083
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		42,909,107	86,579,549
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		1,465,358,488	1,219,442,820
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		35,978,910	30,017,721
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	5,289,133	10,439,101
72	Other Regulatory Assets (182.3)	232	1,550,913,652	1,626,353,730
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,116,069	1,091,392
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)		89,891	88,829
78	Miscellaneous Deferred Debits (186)	233	67,302,539	72,806,094
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)		13,778,067	16,563,180
82	Accumulated Deferred Income Taxes (190)	234	587,517,758	586,940,125
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,263,986,019	2,344,300,172
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		18,550,965,133	16,755,401,518

FOOTNOTE DATA

Schedule Page: 110 Line No.: 57 Column: c

As of December 31, 2009, account 165 Prepayments included $249,055,093 in income taxes receivable from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

Schedule Page: 110 Line No.: 57 Column: d

As of December 31, 2008, account 165 Prepayments included $42,202,974 in income taxes receivable from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	end of 2009/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	3,417,945,896
3	Preferred Stock Issued (204)	250-251	41,463,300	41,463,300
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	1,002,063,956	877,063,956
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	41,288,207	41,288,207
11	Retained Earnings (215, 215.1, 216)	118-119	2,225,701,346	1,687,760,382
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	8,330,470	6,508,778
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-5,819,577	-2,550,680
16	Total Proprietary Capital (lines 2 through 15)		6,648,397,184	5,986,903,425
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,372,343,000	5,510,797,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		35,563	38,281
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		15,413,483	7,963,911
24	Total Long-Term Debt (lines 18 through 23)		6,356,965,080	5,502,871,370
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		57,295,450	59,390,328
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		7,487,871	8,501,565
29	Accumulated Provision for Pensions and Benefits (228.3)		592,543,110	604,317,224
30	Accumulated Miscellaneous Operating Provisions (228.4)		41,878,303	42,256,560
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		409,727,110	490,202,449
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		102,516,932	80,948,143
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,211,448,776	1,285,616,269
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	85,000,000
38	Accounts Payable (232)		539,268,266	744,182,870
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		13,729,206	17,383,942
41	Customer Deposits (235)		31,895,824	21,919,032
42	Taxes Accrued (236)	262-263	46,747,021	28,648,482
43	Interest Accrued (237)		111,568,228	88,654,332
44	Dividends Declared (238)		520,947	520,947
45	Matured Long-Term Debt (239)		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	04/14/2010	end of 2009/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)		15,796,380	14,388,665
48	Miscellaneous Current and Accrued Liabilities (242)		63,197,166	67,406,951
49	Obligations Under Capital Leases-Current (243)		1,725,318	5,768,004
50	Derivative Instrument Liabilities (244)		494,721,339	620,548,360
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		409,727,110	490,202,449
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		909,442,585	1,204,219,136
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		20,946,236	20,259,578
57	Accumulated Deferred Investment Tax Credits (255)	266-267	45,888,892	49,828,356
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	40,157,480	42,762,022
60	Other Regulatory Liabilities (254)	278	64,164,255	76,456,654
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		2,802,655,179	2,095,724,933
64	Accum. Deferred Income Taxes-Other (283)		450,899,466	490,759,775
65	Total Deferred Credits (lines 56 through 64)		3,424,711,508	2,775,791,318
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		18,550,965,133	16,755,401,518

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	4,353,766,380	4,494,585,986		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,279,099,664	2,593,626,077		
5	Maintenance Expenses (402)	320-323	394,816,343	374,652,182		
6	Depreciation Expense (403)	336-337	473,163,461	416,636,387		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	32,391,772	40,332,443		
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)		5,149,968	5,107,035		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,549,004	7,057,628		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	123,877,487	112,424,490		
15	Income Taxes - Federal (409.1)	262-263	-472,156,577	-83,683,183		
16	- Other (409.1)	262-263	-2,026,201	-8,319,652		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,368,522,890	669,322,953		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	688,511,583	356,785,266		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,874,204	-1,874,204		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		3,790,891	4,889,027		
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)		3,515,690,486	3,769,087,216		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		838,075,894	725,498,770		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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		Line No.
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)	
						1
4,353,766,380	4,494,585,986					2
						3
2,279,099,664	2,593,626,077					4
394,816,343	374,652,182					5
473,163,461	416,636,387					6
						7
32,391,772	40,332,443					8
5,479,353	5,479,353					9
5,149,968	5,107,035					10
						11
1,549,004	7,057,628					12
						13
123,877,487	112,424,490					14
-472,156,577	-83,683,183					15
-2,026,201	-8,319,652					16
1,368,522,890	669,322,953					17
688,511,583	356,785,266					18
-1,874,204	-1,874,204					19
						20
						21
3,790,891	4,889,027					22
						23
						24
3,515,690,486	3,769,087,216					25
838,075,894	725,498,770					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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)		838,075,894	725,498,770		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,526,343	2,278,244		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,518,065	2,444,146		
33	Revenues From Nonutility Operations (417)		241,243	233,693		
34	(Less) Expenses of Nonutility Operations (417.1)		28,326	26,272		
35	Nonoperating Rental Income (418)		74,959	60,570		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	1,811,740	-1,905,654		
37	Interest and Dividend Income (419)		20,556,977	10,637,009		
38	Allowance for Other Funds Used During Construction (419.1)		63,955,322	46,616,392		
39	Miscellaneous Nonoperating Income (421)		32,225,273	144,442,511		
40	Gain on Disposition of Property (421.1)		2,267,272	2,378,680		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		121,112,738	202,271,027		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		82,456	263,455		
44	Miscellaneous Amortization (425)		1,263,905	1,165,477		
45	Donations (426.1)		2,997,500	2,848,144		
46	Life Insurance (426.2)		-5,605,297	-2,259,327		
47	Penalties (426.3)		400,132	1,560,618		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,519,511	1,265,718		
49	Other Deductions (426.5)		34,666,110	143,419,880		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		35,324,317	148,263,965		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	576,313	238,746		
53	Income Taxes-Federal (409.2)	262-263	29,005,691	20,014,193		
54	Income Taxes-Other (409.2)	262-263	3,941,391	2,719,596		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	99,093,919	146,049,815		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	99,416,511	146,944,899		
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)		31,135,543	20,012,191		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		54,652,878	33,994,871		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		369,236,117	313,572,989		
63	Amort. of Debt Disc. and Expense (428)		3,786,241	3,072,734		
64	Amortization of Loss on Reaquired Debt (428.1)		2,785,112	4,223,214		
65	(Less) Amort. of Premium on Debt-Credit (429)		2,718	2,718		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		10,264,106	14,625,063		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		35,186,532	34,280,545		
70	Net Interest Charges (Total of lines 62 thru 69)		350,882,326	301,210,737		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		541,846,446	458,282,904		
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)		541,846,446	458,282,904		

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.

	Years Ended December 31,	
	2009	2008
Vehicle Depreciation	$ 13,886,246	$ 13,465,822

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.

	Years Ended December 31,	
	2009	2008
Payroll Tax Expense	$ 38,397,330	$ 37,428,777

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

The credit reported in the current year tax expense is primarily attributable to a provision for net operating loss (tax basis) and tax credit carrybacks for the calendar year ended December 31, 2009. PacifiCorp's net operating loss (tax basis) for calendar year ended December 31, 2009 is primarily attributable to accelerated tax depreciation, tax bonus depreciation taken in excess of book depreciation, and repairs deduction.

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

The credit reported in the prior year tax expense is primarily attributable to a provision for net operating loss (tax basis) and tax credit carrybacks for the calendar year ended December 31, 2008. PacifiCorp's net operating loss (tax basis) is primarily attributable to accelerated tax depreciation and tax bonus depreciation taken in excess of book depreciation.

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

See footnote line 15, column c

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

See footnote 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,684,184,571	1,228,302,955
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adoption of SFAS No. 158 measurement date provisions, net			
11	of tax of ($943,130)	228.3		(1,366,264)
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			(1,366,264)
16	Balance Transferred from Income (Account 433 less Account 418.1)		540,034,706	460,188,558
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				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-9,952	(856,888)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,222,125,535	1,684,184,571
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		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)		2,225,701,346	1,687,760,382
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		6,508,778	7,557,544
50	Equity in Earnings for Year (Credit) (Account 418.1)		1,811,740	(1,905,654)
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unapprop. Retained Earnings (Account 216)		9,952	856,888
53	Balance-End of Year (Total lines 49 thru 52)		8,330,470	6,508,778

FOOTNOTE DATA

Schedule Page: 118 Line No.: 47 Column: c

Appropriated retained earnings due to requirements of certain hydroelectric licensed projects.

Schedule Page: 118 Line No.: 47 Column: d

See footnote for column (c) line 47.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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)	541,846,446	458,282,904
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	492,861,350	430,811,133
5	Amortization:	45,834,002	59,141,936
6			
7	Unrealized Losses/(Gains) on Derivative Contracts	726,000	61,572
8	Deferred Income Taxes (Net)	647,364,615	311,719,127
9	Investment Tax Credit Adjustment (Net)	-3,939,464	-3,939,464
10	Net (Increase) Decrease in Receivables	-10,227,986	4,400,377
11	Net (Increase) Decrease in Inventory	-41,858,225	-57,076,891
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	37,768,396	7,685,336
14	Net (Increase) Decrease in Other Regulatory Assets	12,441,383	-36,836,116
15	Net Increase (Decrease) in Other Regulatory Liabilities	-6,970,542	-2,020
16	(Less) Allowance for Other Funds Used During Construction	63,955,322	46,616,392
17	(Less) Undistributed Earnings from Subsidiary Companies	1,811,740	-1,905,654
18	Amounts Due To/From Affiliates, Net	-216,306,739	-9,844,783
19	Derivative Collateral (Net)	57,400,001	-81,900,000
20	Other Operating Activities:	-30,082,350	-53,394,167
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,461,089,825	984,398,206
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,356,195,937	-1,805,989,623
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	-63,955,322	-46,616,392
31	Acquisitions, Net of Cash Acquired		-307,682,572
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,292,240,615	-2,067,055,803
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,274,203	3,012,032
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		-10,417,000
40	Contributions and Advances from Assoc. and Subsidiary Companies	16,029,414	
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-269,354	-9,698
45	Proceeds from Sales of Investment Securities (a)	458,430	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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 Investing Activities:	3,540,757	4,988,593
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,271,207,165	-2,069,481,876
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	982,802,997	792,126,293
62	Preferred Stock		
63	Common Stock		
64	Equity Contribution	125,000,000	450,000,000
65	Reacquired Bonds		216,470,000
66	Net Increase in Short-Term Debt (c)		84,991,027
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,107,802,997	1,543,587,320
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-138,454,000	-412,408,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Repayment of Capital Lease Obligations	-5,811,642	-709,310
78	Net Decrease in Short-Term Debt (c)	-84,991,027	
79	Reacquired Bonds		-216,470,000
80	Dividends on Preferred Stock	-2,083,790	-2,083,790
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	876,462,538	911,916,220
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	66,345,198	-173,167,450
87			
88	Cash and Cash Equivalents at Beginning of Period	19,665,248	192,832,698
89			
90	Cash and Cash Equivalents at End of period	86,010,446	19,665,248

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

	Years Ended December 31, 2009	Years Ended December 31, 2008
Amortization of Software & Other Intangibles	$ 32,391,772	$ 40,332,443
Amortization of Hydroelectric Relicensing Costs	1,263,905	1,165,477
Amortization of Electric Plant Acquisition Adjustment	5,479,353	5,479,353
Amortization of Regulatory Assets	6,698,972	12,164,663
	$ 45,834,002	$ 59,141,936

Schedule Page: 120 Line No.: 20 Column: a

	Years Ended December 31, 2009	Years Ended December 31, 2008
Coal & Steam Depreciation & Depletion included in Cost of Fuel	$ 13,212,110	$ 12,035,196
PMI Earnings included in Cost of Fuel	(11,386,280)	(8,910,812)
(Gain)/Loss on Sale of Property	(2,357,000)	(2,588,295)
Deferred Credits – Deferred Compensation	(169,928)	(2,125,011)
Accumulated Provision for Pension & Benefits	(32,053,411)	(42,626,647)
Write-Off of Assets Under Construction	4,489,364	4,813,141
Accumulated Provision for Mining/Environ/Decom	(5,286,415)	(3,044,671)
BPA Transmission (Prepayments)/Refunds	4,217,125	(7,488,000)
Long-Term Notes Receivable	314,177	(2,357,519)
Other	(1,062,092)	(1,101,549)
	$ (30,082,350)	$ (53,394,167)

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

	Years Ended December 31, 2009	Years Ended December 31, 2008
Other Investments/Special Funds	$ 1,020,004	$ 3,344,372
Temporary Facilities	(1,062)	26,471
Restricted Cash	2,521,815	1,617,750
	$ 3,540,757	$ 4,988,593

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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 Commission 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 AND SUBSIDIARIES
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining facilities and services and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(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 disclosures required by GAAP adjusted to the FERC basis of presentation, and include specific information requested by the FERC.

The following are the significant differences between the FERC accounting and 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 entities in which a company holds a controlling financial interest be consolidated. 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 Costs of Removal

The accumulated costs of removal for PacifiCorp's utility plant that do not meet the GAAP definition of an asset retirement obligation ("ARO") are classified as a regulatory liability under GAAP and as accumulated depreciation under the FERC accounting and reporting standards.

Income Taxes

Accumulated deferred income taxes are classified as current and non-current on the balance sheet for GAAP. Under the FERC accounting and reporting standards, accumulated deferred income taxes are classified as gross non-current assets and gross non-current liabilities. Additionally, there are certain presentational differences between FERC and GAAP for amounts related to unrecognized tax benefits associated with temporary differences in accordance with FERC Docket No. AI07-2-000, "Accounting and Financial Reporting for Uncertainty in Income Taxes" issued on May 25, 2007.

Interest and penalties on income taxes for GAAP are classified as income tax expense. All such amounts are classified as interest income, interest expense and penalties under the FERC accounting and reporting standards.

Unrealized Gains and Losses on Derivative Instruments

The FERC accounting and reporting standards require that unrealized gains and losses on derivative instruments that are not recorded as a net regulatory asset or accumulated other comprehensive income ("AOCI") be classified gross in the statement of income in accordance with FERC Order 627, "Accounting and Reporting of Financial Instruments, Comprehensive Income, Derivatives and Hedging Activities." Unrealized gains and losses on energy contracts accounted for as derivatives are presented on the Statement of Income as miscellaneous nonoperating income for unrealized gains and as other deductions for unrealized losses. For GAAP, unrealized gains and losses on energy derivative contracts not held for trading purposes are presented on the Statement of Income as revenues for sales contracts and as energy costs and operating expense for purchase and financial swap energy contracts.

Reclassifications

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

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 revenue and expenses during the period. These estimates include, but are not limited to, unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; effects of regulation; long-lived asset recovery; accounting for contingencies, including environmental, regulatory and income tax matters; AROs; and certain assumptions made in accounting for pension and other postretirement benefits. Actual results may differ from the estimates used in preparing the financial statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and assesses whether its regulatory assets and liabilities are probable of future inclusion in regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking 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 continuous assessment, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in regulated rates. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs or income will be included in regulated rates, the related regulatory assets and liabilities will be written off to operating income, refunded to customers or reflected as an adjustment to future regulated rates.

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Market participants are assumed to be independent, knowledgeable, and able and willing to transact. Nonperformance or credit risk is considered when determining the fair value of assets and liabilities. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value.

Cash Equivalents, Restricted Cash and Investments

Cash equivalents consist of funds invested in commercial paper, money market accounts and in other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other special funds and special deposits on the Comparative Balance Sheet. Total cash and cash equivalents were as follows as of December 31 (in millions):

	2009	2008
Cash (131)	$ 4	$ 16
Working funds (135)	-	-
Temporary cash investments (136)	82	4
Total cash and cash equivalents	$ 86	$ 20

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 ability of customers to pay the amounts owed to PacifiCorp or the outcome of any pending disputes. The change in the balance of the allowance for doubtful accounts, which is included in accumulated provision for uncollectible accounts on the Comparative Balance Sheet was as follows for the years ended December 31 (in millions):

	2009	2008
Beginning balance	$ 9	$ 7
Charged to operation expenses, net	12	14
Write-offs, net	(14)	(12)
Ending balance	$ 7	$ 9

Derivatives

PacifiCorp employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Comparative Balance Sheet as either assets or liabilities and are stated at fair value unless they are designated as normal purchases and normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect reductions permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives used in 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. Normal purchases and normal sales are not marked-to-market and operating revenues or operation expenses are recognized on the Statement of Income when the contracts settle.

For PacifiCorp's derivatives designated as hedging contracts, PacifiCorp formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. PacifiCorp formally documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included on the Statements of Accumulated Comprehensive Income, Comprehensive Income, and Hedging Activities as AOCI, net of tax, until the contract settles and the hedged item is recognized in earnings. 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 AOCI will remain in AOCI until the contract settles and the hedged item is recognized in earnings, unless it becomes probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI are immediately recognized in earnings.

For PacifiCorp's derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as net regulatory assets and liabilities. For contracts not probable of inclusion in regulated rates, changes in fair value are recognized in earnings.

Inventories

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

Net Utility Plant

General

Utility plant is recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which includes debt and equity allowance for funds used during construction ("AFUDC"). 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 related assets are charged to operating expense as incurred.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by PacifiCorp's various regulatory authorities. Periodic depreciation studies are completed to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs, including AROs and other costs of removal. Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal ARO, are reflected in accumulated provision for depreciation on the Comparative Balance Sheet, and as such costs are incurred, the provision is reduced.

Generally when PacifiCorp retires or sells a component of depreciable utility plant, it charges the original cost and any cost of removal and salvage to accumulated provision for depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

PacifiCorp records debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance additions to utility plant. AFUDC is capitalized as a component of utility plant, with offsetting credits to the Statement of Income. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related asset, as well as recover these costs through depreciation expense over the expected useful life of the related assets.

Asset Retirement Obligations

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and 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 ARO liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to utility plant) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in utility plant and amounts recovered in depreciation rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes unbilled, as well as billed, amounts. As of December 31, 2009 and 2008, unbilled revenue was $214 million and $211 million, respectively, and is included in accrued utility revenues on the Comparative Balance Sheet. Rates charged are established by regulators or contractual agreements.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, customer usage patterns, historical trends, volumes, line losses, retail rate changes and composition of customer classes.

PacifiCorp records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statement of Income.

Income Taxes

Berkshire Hathaway includes PacifiCorp in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred tax assets and liabilities are based on differences between the financial statement and tax basis of assets and liabilities using estimated tax rates expected to be 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. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling $401 million and $409 million as of December 31, 2009 and 2008, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense.

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 income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. 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. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse effect on PacifiCorp's financial results. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Estimated interest and penalties, if any, related to uncertain tax positions are included in interest income, interest expense and penalties on the Statement of Income.

Segment Information

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2010-06 ("ASU No. 2010-06"), which amends FASB Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures" ("ASC Topic 820"). ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. This guidance is effective for interim and annual reporting periods beginning after December 15, 2009, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which is effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

In August 2009, the FASB issued ASU No. 2009-05, which amends ASC Topic 820. ASU No. 2009-05 clarifies how to measure the fair value of a liability for which a quoted price in an active market for the identical liability is not available. This guidance also clarifies that both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required represent Level 1 fair value measurements. PacifiCorp adopted this guidance as of October 1, 2009 and the adoption did not have a material impact on PacifiCorp's financial results and disclosures included within Notes to Financial Statements.

In April 2009, the FASB issued authoritative guidance (included in ASC Topic 820) that clarifies the determination of fair value when a market is not active and if a transaction is not orderly. In addition, this guidance amends previous GAAP to require disclosures in interim and annual periods of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, during the period and defines "major categories" consistent with those described in previously existing GAAP. PacifiCorp adopted this guidance as of April 1, 2009 and the adoption did not have a material impact on PacifiCorp's financial results and disclosures included within Notes to Financial Statements.

In December 2008, the FASB issued authoritative guidance (included in ASC Topic 715, "Compensation – Retirement Benefits") that requires enhanced disclosures about plan assets of defined benefit pension and other postretirement benefit plans to enable investors to better understand how investment allocation decisions are made and the major categories of plan assets. In addition, this guidance requires disclosure of the inputs and valuation techniques used to measure fair value and the effect of fair value measurements using significant unobservable inputs on changes in plan assets and establishes disclosure requirements for significant concentrations of risk within plan assets. PacifiCorp adopted this guidance as of December 31, 2009 and included the required disclosures within Notes to Financial Statements. Refer to Note 11 for additional discussion.

In March 2008, the FASB issued authoritative guidance (included in ASC Topic 815, "Derivatives and Hedging") that requires enhanced disclosures about derivative contracts and hedging activities to enable investors to better understand how and why an entity uses derivative contracts and their effects on an entity's financial results. PacifiCorp adopted this guidance as of March 31, 2009 and included the required disclosures within Notes to Financial Statements. Refer to Note 7 for additional discussion.

(3) Net Utility Plant

Depreciable Lives

The average depreciable lives of utility plant currently in use by category are as follows:

Generation:	
Steam plant	20 – 57 years
Hydroelectric plant	24 – 80 years
Wind plant	25 years
Other plant	15 – 40 years
Transmission	25 – 75 years
Distribution	44 – 52 years
Intangible plant (1)	5 – 50 years
Other	5 – 29 years

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

Utility Plant Acquisition

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating facility located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the facility. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the facility's operations have been included in PacifiCorp's financial statements since the acquisition date.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in utility plant purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in utility plant had an original cost of $157 million as of December 31, 2009 and 2008, and accumulated provision for depreciation, amortization and depletion of $96 million and $91 million as of December 31, 2009 and 2008, respectively.

Depreciation Study

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change its rates of depreciation prospectively based on a new depreciation study. PacifiCorp received approval to change the depreciation rates effective January 1, 2008. The Oregon Public Utility Commission (the "OPUC") order required additional modifications related to the depreciation lives of coal-fired generating facilities, which were approved in August 2008. The revised depreciation rates generally reflect an extension of the lives of PacifiCorp's assets. The most significant change resulted in an increase in the range of depreciable lives for steam plant from 20 - 43 years to 20 - 57 years. The revised depreciation rates resulted in a benefit to income before income tax expense during the year ended December 31, 2008 of approximately $47 million.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each generating facility or transmission line. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Statement of Income include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2009 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 – 4 (1)	67%	$ 1,031	$ 508	$ 42
Wyodak (1)	80	339	183	20
Hunter No. 1	94	306	158	35
Colstrip Nos. 3 and 4 (1)	10	248	131	1
Hunter No. 2	60	194	95	24
Hermiston (2)	50	174	45	-
Craig Nos. 1 and 2	19	168	85	2
Hayden No. 1	25	46	24	2
Foote Creek	79	37	16	-
Hayden No. 2	13	28	16	1
Other transmission and distribution facilities	Various	84	26	29
Total		$ 2,655	$ 1,287	$ 156

(1) Includes transmission lines and substations.

(2) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

(5) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future regulated rates. Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp had regulatory assets not earning a return on investment of $1.385 billion and $1.460 billion as of December 31, 2009 and 2008, respectively.

Rate Matters

Oregon Senate Bill 408 ("SB 408")

SB 408 requires PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers to file an annual report each October with the OPUC comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. If after its review, the OPUC determines the amount of income taxes collected differs from the amount of income taxes paid by more than $100,000, the OPUC must require the public utility to establish an automatic adjustment clause to account for the difference.

In April 2008, the OPUC approved the recovery of $35 million, plus interest, related to the 2006 tax year. The OPUC's April 2008 order on PacifiCorp's 2006 tax report is being challenged by the Industrial Customers of Northwest Utilities, which filed a petition in May 2008 with the Oregon Court of Appeals seeking judicial review of the April 2008 order. PacifiCorp believes the outcome of these proceedings will not have a material impact on its financial results.

In October 2009, PacifiCorp filed its 2008 tax report under SB 408. PacifiCorp's filing for the 2008 tax year indicated that PacifiCorp paid $38 million more in income taxes than was collected in rates from its retail customers. In January 2010, PacifiCorp entered into a stipulation with OPUC staff and the Citizens' Utility Board of Oregon, agreeing to a lower recovery totaling $2 million, including interest. In April 2010, the OPUC issued an order adopting the stipulation in its entirety.

(6) Fair Value Measurements

The carrying amounts of PacifiCorp's cash, certain cash equivalents, receivables, special funds, other investments, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the financial statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 – Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including its own data.

The following table presents PacifiCorp's assets and liabilities recognized on the Comparative Balance Sheet and measured at fair value on a recurring basis as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other (1)**	**Total**
Assets (2):					
Investments in available-for-sale securities:					
Money market mutual funds (3)	$ 94	$ -	$ -	$ -	$ 94
Commodity derivatives	-	285	6	(140)	151
	$ 94	$ 285	$ 6	$ (140)	$ 245
Liabilities:					
Commodity derivatives	$ -	$ (274)	$ (386)	$ 165	$ (495)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $25 million.

(2) Refer to Note 11 for information regarding the fair value of pension and other postretirement benefit plan assets as it is excluded from these amounts.

(3) Amounts are included in other investments, other special funds and temporary cash investments on the Comparative Balance Sheet. The fair value of these money market mutual funds approximates cost.

The following table presents PacifiCorp's assets and liabilities recognized on the Comparative Balance Sheet and measured at fair value on a recurring basis as of December 31, 2008 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other (1)**	**Total**
Assets (2):					
Investments in available-for-sale securities:					
Money market mutual funds (3)	$ 17	$ -	$ -	$ -	$ 17
Commodity derivatives	-	474	88	(302)	260
	$ 17	$ 474	$ 88	$ (302)	$ 277
Liabilities:					
Commodity derivatives	$ -	$ (485)	$ (496)	$ 361	$ (620)

(1) Primarily represents netting under master netting arrangements and a net cash collateral receivable of $82 million.

(2) Does not include investments in either pension or other postretirement benefit plan assets.

(3) Amounts are included in other investments, other special funds and temporary cash investments on the Comparative Balance Sheet. The fair value of these money market mutual funds approximates cost.

PacifiCorp's investments in money market mutual funds are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics.

When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves derived from market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the first six years; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. Refer to Note 7 for further discussion regarding PacifiCorp's risk management and hedging activities.

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. Option components are valued using Black-Scholes-type models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

The following table reconciles the beginning and ending balances of PacifiCorp's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2009	2008
Beginning balance	$ (408)	$ (311)
Changes in fair value recognized in regulatory assets	(5)	(98)
Purchases, sales, issuances and settlements	56	(12)
Net transfers into or out of Level 3	(23)	13
Ending balance	$ (380)	$ (408)

PacifiCorp's long-term debt is carried at cost on the financial statements. The fair value of PacifiCorp's long-term debt has been estimated based on quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying amount of PacifiCorp's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying amount and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2009		2008	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	$ 6,357	$ 6,843	$ 5,503	$ 5,769

(7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity and natural gas commodity price risk as it has an obligation to serve retail customer load in its regulated service territories. PacifiCorp's load and generation assets represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt, commercial paper and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity risk, PacifiCorp uses commodity derivative contracts, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates and by monitoring market changes in interest rates. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to effectively modify PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 6 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases and normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Comparative Balance Sheet as of December 31, 2009 (in millions):

	Balance Sheet Locations				
	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
Not Designated as Hedging Contracts (1)(2):					
Commodity assets	$ 191	$ 61	$ 8	$ 31	$ 291
Commodity liabilities	(29)	(17)	(142)	(472)	(660)
Total	162	44	(134)	(441)	(369)
Designated as Cash Flow Hedging Contracts:					
Commodity assets	-	-	-	-	-
Commodity liabilities	-	-	-	-	-
Total	-	-	-	-	-
Total derivatives	162	44	(134)	(441)	(369)
Cash collateral receivable (payable)	(54)	(1)	49	31	25
Total derivatives – net basis	$ 108	$ 43	$ (85)	$ (410)	$ (344)

(1) Derivative contracts within these categories are subject to master netting arrangements and are presented on a net basis on the Comparative Balance Sheet.

(2) The majority of PacifiCorp's commodity derivatives not designated as hedging contracts are expected to be included in regulated rates and as of December 31, 2009, a net regulatory asset of $367 million was recorded related to the net derivative liabilities of $369 million.

Not Designated as Hedging Contracts

For PacifiCorp's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the year ended December 31(in millions):

	2009
Beginning balance	$ 442
Changes in fair value recognized in net regulatory assets	(74)
Gains reclassified to earnings – operating revenues	222
Losses reclassified to earnings – operation expenses	(223)
Ending balance	$ 367

For PacifiCorp's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a net regulatory asset or liability, unrealized gains and losses are recorded on the Statements of Income as miscellaneous nonoperating income for unrealized gains and as other deductions for unrealized losses. The following table summarizes the pre-tax gains (losses) included within the Statement of Income associated with PacifiCorp's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the year ended December 31 (in millions):

	2009
Commodity derivatives:	
Miscellaneous non-operating income	23
Other deductions	(17)
Total	$ 6

Designated as Cash Flow Hedging Contracts

PacifiCorp uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices. The gains and losses on these derivative contracts are recognized in other comprehensive income. Derivative contracts accounted for as cash flow hedges were not material for the year ended December 31, 2009. Hedge ineffectiveness on contracts with unrealized gains is recognized as miscellaneous non-operating income and hedge ineffectiveness on contracts with unrealized losses is recognized as other deductions. For the years ended December 31, 2009 and 2008, hedge ineffectiveness was insignificant.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2009
Commodity contracts:		
Electricity sales	Megawatt hours	(22)
Natural gas purchases	Decatherms	201
Fuel purchases	Gallons	14

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketers, financial institutions and other market participants in conjunction with wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

PacifiCorp analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain derivative contracts contain provisions that require PacifiCorp to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2009, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $353 million as of December 31, 2009, for which PacifiCorp had posted collateral of $80 million. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2009, PacifiCorp would have been required to post $159 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings or other factors.

(8) Short-Term Borrowings and Other Financing Agreements

PacifiCorp has two unsecured revolving credit facilities totaling $1.395 billion. The credit facilities include a fixed or variable borrowing option for which rates vary based on the borrowing option and PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These facilities support PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. As of December 31, 2009, PacifiCorp had letters of credit issued under the credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations and had no borrowings outstanding under its credit facilities. In addition, the credit facilities support $38 million of unenhanced variable-rate tax-exempt bond obligations as of December 31, 2009. As of December 31, 2008, PacifiCorp had outstanding commercial paper borrowings of $85 million at an average rate of 1%. Each revolving credit agreement includes a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0.. PacifiCorp was in compliance with the covenants of its revolving credit and the other above-noted financing agreements as of December 31, 2009.

The following table summarizes PacifiCorp's availability under its two unsecured revolving credit facilities as of December 31, 2009 (in millions):

Total unsecured revolving credit facilities	$	1,395
Less:		
Short-term debt (credit facility borrowings or commercial paper)		-
Support for unenhanced variable-rate tax-exempt bond obligations		(38)
Letters of credit supporting variable-rate tax-exempt bond obligations		(220)
Net unsecured revolving credit facilities available	$	1,137
Total bank commitment amounts under credit agreements:		
January 1, 2010 through July 6, 2011	$	1,395
July 7, 2011 through July 6, 2012		1,355
July 7, 2012 through October 23, 2012		1,265
October 24, 2012 through July 6, 2013		630

As of December 31, 2009, PacifiCorp had approximately $15 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These committed bank arrangements were all fully available as of December 31, 2009 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

(9) Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (in millions):

	2009			2008	
	Par Value	Amount	Average Interest Rate	Amount	Average Interest Rate
Long-term debt:					
First mortgage bonds:					
5.0% to 9.2%, due through 2014	$ 1,047	$ 1,047	6.5%	$ 1,185	6.6%
5.5% to 8.7%, due 2015 to 2019	862	858	5.6	511	5.7
6.7% to 8.5%, due 2021 to 2023	324	324	7.7	324	7.7
6.7% due 2026	100	100	6.7	100	6.7
5.9% to 7.7% due 2031 to 2034	500	499	7.0	499	7.0
5.3% to 6.4%, due 2035 to 2039	2,800	2,790	6.0	2,145	6.0
Tax-exempt bond obligations:					
Variable rates, due 2013 (1)	41	41	0.3	41	0.8
Variable rates, due 2014 to 2025	325	325	0.5	325	1.1
Variable rates, due 2024 (1)	176	176	0.2	176	0.9
Variable rates, due 2014 to 2025 (1) (2)	113	113	3.8	113	3.8
5.6% to 5.7%, due 2021 to 2023 (1)	71	71	5.6	71	5.6
6.2% due 2030	13	13	6.2	13	6.2
Total long-term debt	$ 6,372	$ 6,357		$ 5,503	
Capital lease obligations:					
8.8% to 14.8%, due through 2036	$ 59	$ 59	11.7	$ 65	11.6

(1) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) Interest rates currently fixed for a term at 3.4% to 4.1%, with $45 million and $68 million scheduled to reset in 2010 and 2013, respectively.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $19.8 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage as of December 31, 2009.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018 and $300 million of its 6.35% First Mortgage Bonds due July 15, 2038.

In March 2010, PacifiCorp received regulatory authority from the Idaho Public Utilities Commission to issue an additional $2.0 billion of long-term debt through February 28, 2015. PacifiCorp has regulatory authority from the OPUC to issue an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance.

As of December 31, 2009, $5.2 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2009, $542 million of variable-rate tax-exempt bond obligations and $84 million of fixed-rate tax-exempt bond obligations were redeemable at PacifiCorp's option at par. The remaining long-term debt was not redeemable as of December 31, 2009.

As of December 31, 2009, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available as of December 31, 2009 and expire periodically through May 2012.

PacifiCorp's letters of credit 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 1.0. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of December 31, 2009, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through October 2036 for transportation services, power purchase agreements, real estate and for the use of certain equipment. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to three of PacifiCorp's generating facilities. Net assets accounted for as capital leases of $59 million and $65 million as of December 31, 2009 and 2008, respectively, were included in net utility plant on the Comparative Balance Sheet.

As of December 31, 2009, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts, for 2010 and thereafter are as follows (in millions):

	Long-Term Debt	Capital Lease Obligations	Total
2010	$ 14	$ 9	$ 23
2011	587	8	595
2012	17	8	25
2013	261	12	273
2014	253	8	261
Thereafter	5,240	94	5,334
Total	6,372	139	6,511
Unamortized discount	(15)	-	(15)
Amounts representing interest (1)	-	(80)	(80)
Total	$ 6,357	$ 59	$ 6,416

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

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of 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. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs 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, distribution and other assets cannot currently be estimated and no amounts are recognized on the financial statements other than those included in the regulatory removal cost liability established via approved depreciation rates.

The change in the balance of the total ARO liability is summarized as follows as of December 31 (in millions):

	2009	2008
Balance, January 1	$ 81	$ 75
Additions	3	2
Retirements	(5)	(4)
Change in estimated costs (1)	19	4
Accretion (2)	5	4
Balance, December 31	$ 103	$ 81

(1) Results from changes in the timing and amounts of estimated cash flows for certain plant and mine reclamation.

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

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. For decommissioning, PacifiCorp is committed to pay a proportionate share of the decommissioning costs based upon its ownership percentage, or in the case of mine reclamation obligations, PacifiCorp has committed to pay a proportionate share of mine 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's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides certain postretirement healthcare and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors a defined contribution 401(k) employee savings plan (the "401(k) Plan"). Non-union employees hired on or after January 1, 2008 and certain union new hires are not eligible to participate in the PacifiCorp Retirement Plan (the "Retirement Plan"). These employees are eligible to receive enhanced benefits under the 401(k) Plan.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the Retirement Plan; the Supplemental Executive Retirement Plan (the "SERP"); and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. All non-union Retirement Plan participants, as well as certain union participants, earn benefits based on a cash balance formula. Certain union employees covered under the Retirement Plan continue to earn benefits 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.

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 these other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust union plans for postretirement benefits offered to certain bargaining units.

Measurement Date Change

PacifiCorp adopted the measurement date provisions included in the authoritative guidance for retirement benefits at December 31, 2008, which requires that an employer measure plan assets and benefit obligations at the end of the employer's fiscal year. Effective December 31, 2008, PacifiCorp changed its measurement date from September 30 to December 31 and recorded a $14 million transitional adjustment. The components of the measurement date change transitional adjustment were as follows on a pre-tax basis (in millions):

	Pension	Other Postretirement	Total
Service cost	$ 7	$ 2	$ 9
Interest cost	16	8	24
Expected return on plan assets	(18)	(7)	(25)
Net amortization	2	4	6
Total	$ 7	$ 7	$ 14

The $14 million transitional adjustment included $12 million recorded as an increase in regulatory assets for the portion considered probable of inclusion in regulated rates and $2 million recorded as a reduction ($1 million after-tax) in retained earnings for the portion not considered probable of inclusion in regulated rates. The $12 million increase to regulatory assets is being amortized over three to 10 years based on agreements with various state regulatory commissions. The recognition of service cost, interest cost and expected return on plan assets, totaling $8 million, resulted in an increase in pension and other postretirement liabilities. The $6 million net amortization represents recognition of prior service cost, net transition obligation and actuarial net loss and resulted in a reduction in regulatory assets.

Curtailments

In August 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in their current cash balance formula of the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan. The election was effective January 1, 2009 and resulted in the recognition of a $38 million curtailment gain. PacifiCorp recorded $36 million of the curtailment gain as a reduction to regulatory assets as of December 31, 2008, representing the amount to be returned to customers in rates. The reduction to regulatory assets is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions.

Effective December 31, 2007, Local Union No. 659 of the International Brotherhood of Electrical Workers ("Local 659") elected to cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result of this election, the Local 659 participants' Retirement Plan benefits were frozen as of December 31, 2007. This change resulted in a $2 million curtailment gain that was recorded as a reduction to regulatory assets as of December 31, 2008 based on the requirement to return the amount to customers in rates. The reduction to regulatory assets is being amortized over a period of three to 10 years based on agreements with various state regulatory commissions. Also as a result of this change, PacifiCorp's pension liability and regulatory assets each decreased by $13 million.

Effective March 31, 2010, Utility Workers Union of America Local Union No. 127 ("Local 127") ceased participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result, the Local 127 participants' Retirement Plan benefits were frozen on March 31, 2010. The impacts of this change are not expected to significantly impact PacifiCorp's financial results.

Change in Benefit Formula

Effective June 1, 2007, PacifiCorp switched from a traditional final-average-pay formula for the Retirement Plan to a cash balance formula for its non-union employees. As a result of the change, benefits under the traditional final-average-pay formula were frozen as of May 31, 2007 for non-union employees, and PacifiCorp's pension liability and regulatory assets each decreased by $111 million.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. 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 after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008 (2)	2009	2008 (2)
Service cost (1)	$ 16	$ 27	$ 5	$ 7
Interest cost	71	67	33	33
Expected return on plan assets	(70)	(72)	(29)	(28)
Net amortization	10	7	12	15
Net amortization of regulatory assets	(8)	-	1	-
Curtailment gain	-	(2)	-	-
Net periodic benefit cost	$ 19	$ 27	$ 22	$ 27

(1) Service cost excludes $11 million of contributions to the joint trust union plans during each of the years ended December 31, 2009 and 2008.

(2) Excludes the impact of the measurement date change and the portion of the curtailment gains required to be returned to customers in rates. Refer to "Measurement Date Change" and "Curtailments" above.

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Plan assets at fair value, beginning of year	$ 692	$ 963	$ 284	$ 378
Employer contributions	54	70	24	42
Participant contributions	-	-	9	14
Actual return on plan assets	160	(224)	70	(103)
Benefits paid	(81)	(117)	(37)	(47)
Plan assets at fair value, end of year	$ 825	$ 692	$ 350	$ 284

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Benefit obligation, beginning of year	$ 1,070	$ 1,111	$ 489	$ 536
Service cost (1)	16	34	5	9
Interest cost (1)	71	83	33	41
Participant contributions	-	-	9	14
Plan amendments	(1)	(7)	(4)	(12)
Curtailment	-	(13)	-	-
Actuarial loss (gain)	124	(21)	47	(56)
Benefits paid, net of Medicare subsidy	(81)	(117)	(34)	(43)
Cost of termination benefits	-	-	-	-
Benefit obligation, end of year	$ 1,199	$ 1,070	$ 545	$ 489
Accumulated benefit obligation, end of year	$ 1,178	$ 1,048		

(1) Included in the pension and other postretirement liabilities in connection with the measurement date change in 2008 was additional service cost of $7 million and $2 million and additional interest cost of $16 million and $8 million for the pension and other postretirement benefit plans, respectively.

The funded status of the plans and the amounts recognized on the Comparative Balance Sheet are as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Plan assets at fair value, end of year	$ 825	$ 692	$ 350	$ 284
Less – Benefit obligation, end of year	1,199	1,070	545	489
Funded status	$ (374)	$ (378)	$ (195)	$ (205)
Amounts recognized on the Comparative Balance Sheet:				
Other current liabilities	$ (4)	$ (4)	$ -	$ -
Other long-term liabilities	(370)	(374)	(195)	(205)
Amounts recognized	$ (374)	$ (378)	$ (195)	$ (205)

The SERP has no plan assets; however, 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. 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 $39 million and $38 million as of December 31, 2009 and 2008, respectively. These assets are not included in the plan assets in the above table, but are reflected on the Comparative Balance Sheet. The portion of the pension plans' projected benefit obligation related to the SERP was $55 million and $50 million as of December 31, 2009 and 2008, respectively. The SERP's accumulated benefit obligation totaled $55 million and $50 million as of December 31, 2009 and 2008, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost is as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2009	2008	2009	2008
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss	$ 523	$ 508	$ 135	$ 128
Prior service (credit) cost	(60)	(68)	-	1
Net transition obligation	-	-	29	45
Regulatory deferrals (1)	(24)	(32)	5	6
Total	$ 439	$ 408	$ 169	$ 180

(1) Consists of amounts related to the portion of the curtailment gains and the measurement date change transitional adjustment that are considered probable of inclusion in regulated rates.

A reconciliation of the beginning and ending balances of amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2009 and 2008 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss, Net	Total
Pension			
Balance, January 1, 2008	$ 132	$ 6	$ 138
Net loss (gain) arising during the year	293	(2)	291
Prior service credit arising during the year	(7)	-	(7)
Curtailment gains	(11)	-	(11)
Measurement date change	6	-	6
Net amortization (1)	(9)	-	(9)
Total	272	(2)	270
Balance, December 31, 2008	$ 404	$ 4	$ 408
Balance, January 1, 2009	$ 404	$ 4	$ 408
Net loss arising during the year	29	5	34
Prior service credit arising during the year	(1)	-	(1)
Net amortization	(2)	-	(2)
Total	26	5	31
Balance, December 31, 2009	$ 430	$ 9	$ 439

	Regulatory Asset	Deferred Income Taxes	Total
Other Postretirement			
Balance, January 1, 2008	$ 95	$ 27	$ 122
Net loss (gain) arising during the year	91	(7)	84
Prior service credit arising during the year	(13)	-	(13)
Measurement date change	6	-	6
Net amortization (1)	(19)	-	(19)
Total	65	(7)	58
Balance, December 31, 2008	$ 160	$ 20	$ 180
Balance, January 1, 2009	$ 160	$ 20	$ 180
Net loss arising during the year	4	3	7
Prior service credit arising during the year	(1)	-	(1)
Transition obligation credit arising during the year	(3)	-	(3)
Net amortization	(14)	-	(14)
Total	(14)	3	(11)
Balance, December 31, 2009	$ 146	$ 23	$ 169

(1) Included in the net amortization for 2008 was $2 million and $4 million for the pension and other postretirement benefit plans, respectively, in connection with the measurement date change in 2008.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2010 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Net Transition Obligation	Regulatory Deferrals	Total
Pension	$ 32	$ (9)	$ -	$ (9)	$ 14
Other postretirement	4	-	10	1	15
Total	$ 36	$ (9)	$ 10	$ (8)	$ 29

Plan Assumptions

Assumptions used to determine benefit obligations and net periodic benefit cost were as follows for the years ended December 31:

	Pension		Other Postretirement	
	2009	2008	2009	2008
Benefit obligations as of the measurement date:				
Discount rate	5.80%	6.90%	5.85%	6.90%
Rate of compensation increase	3.00	3.50	N/A	N/A
Net benefit cost for the period ended:				
Discount rate	6.90%	6.30%	6.90%	6.45%
Expected return on plan assets	7.75	7.75	7.75	7.75
Rate of compensation increase	3.50	4.00	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

Assumed healthcare cost trend rates were as follows as of December 31:

	2009	2008
Healthcare cost trend rate assumed for next year – under 65	8%	8%
Healthcare cost trend rate assumed for next year – over 65	8	6
Rate that the cost trend rate gradually declines to	5	5
Year that the rate reaches the rate it is assumed to remain at – under 65	2016	2012
Year that the rate reaches the rate it is assumed to remain at – over 65	2016	2010

A one-percentage-point change in assumed healthcare cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 3	$ (2)
Effect on other postretirement benefit obligation	31	(26)

Contributions and Benefit Payments

Employer contributions to the pension, other postretirement benefit and joint trust union plans are expected to be $109 million, $25 million and $12 million, respectively, during 2010. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. PacifiCorp's funding policy for its other postretirement benefit plans is to contribute an amount equal to the sum of the net periodic benefit cost and the Medicare subsidies expected to be earned during the period.

The Plan's expected benefit payments to participants for its pension and other postretirement benefit plans for 2010 through 2014 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	Gross	Medicare Subsidy	Net of Subsidy
2010	$ 99	$ 34	$ (3)	$ 31
2011	102	37	(3)	34
2012	104	39	(4)	35
2013	111	41	(4)	37
2014	116	43	(5)	38
2015 – 2019	525	239	(32)	207

Plan Assets

Investment Policy and Asset Allocation

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of fixed income securities, equity securities and other alternative investments. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. PacifiCorp manages the investment portfolio in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption for each plan is based on a weighted-average of the expected performance for the types of assets in which the plans invest.

PacifiCorp's target allocations (percentage of plan assets) for the pension and other postretirement benefit plan assets are as follows as of December 31, 2009:

	Pension(1)	Other Postretirement(1)
	%	%
Cash and cash equivalents	0 – 1	0 – 1
Equity securities (2)	53 – 57	61 – 65
Fixed-income securities (2)	33 – 37	33 – 37
Limited partnership interests	8 – 12	1 – 3

(1) PacifiCorp's pension plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit plans are held in two Voluntary Employees' Beneficiaries Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plans include the separate account of the pension plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages, investment funds have been allocated based on the underlying investments in equity and fixed-income securities.

The following table presents the fair value of PacifiCorp's plan assets, by major category, as of December 31, 2009 (in millions):

	Input Levels for Fair Value Measurements			
	Level 1 (1)	Level 2 (1)	Level 3 (1)	Total
Pension				
Cash and cash equivalents	$ -	$ 4	$ -	$ 4
Fixed-income securities:				
United States government obligations	20	-	-	20
Corporate obligations	-	44	-	44
International government obligations	-	65	-	65
Municipal obligation	-	2	-	2
Agency, asset and mortgage-backed obligations	-	43	-	43
Equity securities:				
United States equity securities	296	-	-	296
International equity securities	4	-	-	4
Investment funds (2)	95	168	-	263
Limited partnership interests (3)	-	-	80	80
Total (4)	$ 415	$ 326	$ 80	$ 821
Other postretirement				
Cash and cash equivalents	$ 3	$ -	$ -	$ 3
Fixed-income securities:				
United States government obligations	2	-	-	2
Corporate obligations	-	4	-	4
International government obligations	-	6	-	6
Agency, asset and mortgage-backed obligations	-	4	-	4
Equity securities:				
United States equity securities	115	-	-	115
International equity securities	2	-	-	2
Investment funds (2)	101	104	-	205
Limited partnership interests (3)	-	-	8	8
Total (4)	$ 223	$ 118	$ 8	$ 349

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds for the pension and other postretirement benefit plans include investments of 14% and 29%, respectively, in United States equity securities; 49% and 23%, respectively, in international equity securities; 13% and 17%, respectively, in United States government obligations; 8% and 10%, respectively, in corporate obligations; 9% and 11%, respectively, in international government obligations; and 7% and 10%, respectively, in agency, asset and mortgage-backed obligations.

(3) Limited partnership interests include several private equity funds that invest primarily in buyout, growth equity and venture capital.

(4) Net receivables of $4 million and $1 million, respectively, related to the pension and other postretirement benefit plans are excluded from the fair value measurement hierarchy.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnerships are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information.

The following table reconciles the beginning and ending balances of PacifiCorp's plan assets measured at fair value using significant Level 3 inputs for the year ended December 31, 2009 (in millions):

	Limited Partnership Interests	
	Pension	Other Postretirement
Balance, January 1, 2009	$ 78	$ 7
Actual return on plan assets still held at period end (1)	5	1
Purchases, sales, issuances and settlements	(3)	-
Balance, December 31, 2009	$ 80	$ 8

(1) Actual return on pension plan assets for limited partnership interests consisted of unrealized appreciation of $5 million related to assets held at December 31, 2009.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes to the 401(k) Plan. PacifiCorp's contributions were $34 million and $23 million during the years ended December 31, 2009 and 2008, respectively. As previously described, certain participants now receive enhanced benefits in the 401(k) Plan and no longer accrue benefits in the Retirement Plan.

(12) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2009	2008
Current:		
Federal	$ (443)	$ (64)
State	2	(6)
Total	(441)	(70)
Deferred:		
Federal	646	276
State	34	36
Total	680	312
Investment tax credits	(4)	(4)
Total income tax expense	$ 235	$ 238

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2009	2008
Federal statutory tax rate	35%	35%
State taxes, net of federal benefit	3	3
Tax credits (1)	(6)	(5)
Other	(2)	1
Effective income tax rate	30%	34%

(1) Primarily attributable to the impact of federal renewable electricity production tax credits related to qualifying wind-powered generating facilities that extend 10 years from the date the facilities were placed in service.

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2009	2008
Deferred tax assets:		
Employee benefits	$ 244	$ 246
Derivative contracts	140	169
Regulatory liabilities	40	42
Other	164	130
	588	587
Deferred tax liabilities:		
Utility plant	(2,381)	(1,656)
Regulatory assets	(838)	(880)
Other	(35)	(50)
	(3,254)	(2,586)
Net deferred tax liability	$ (2,666)	$ (1,999)

The sale of PacifiCorp to MEHC on March 21, 2006 triggered certain tax related events that remain unsettled. PacifiCorp does not believe that the tax, if any, arising from the ultimate settlement of these events will have a material impact on its financial results.

As of December 31, 2009 and 2008, PacifiCorp had a net liability of $75 million and a net asset of $13 million, respectively, for uncertain tax positions. As of December 31, 2009 and 2008, the net liability for uncertain tax positions included $6 million and the net asset for uncertain tax positions included $14 million, respectively, of tax positions that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2003 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

(13) Commitments and Contingencies

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, penalties and other costs in substantial amounts and are described below.

Legal Matters

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal 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 that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of $32,500 per day per violation and the plaintiffs' costs of litigation. In August 2009, the court ruled on a number of summary judgment motions by which it determined that the plaintiffs have sufficient legal standing to proceed with their complaint and that all other issues raised in the summary judgment motions will be resolved at trial. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement will be memorialized in a consent decree to be filed with the United States Environmental Protection Agency (the "EPA") for review and also with the court for review and approval. If approved by the court as expected, the settlement is not expected to have a material impact on PacifiCorp's financial results.

Environmental Regulation

Environmental Matters

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with current environmental requirements.

New Source Review

As part of an industry-wide investigation to assess compliance with the New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") provisions, the EPA has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities, and it has been engaged in periodic discussions with the EPA over several years regarding its historical projects and their compliance with NSR and PSD provisions. An NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements. The impact of these additional emissions controls, costs and penalties, if any, on PacifiCorp's financial results cannot be determined at this time.

Accrued Environmental Costs

PacifiCorp is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of PacifiCorp's operations and sites owned by third parties. PacifiCorp accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, PacifiCorp's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. The liability recorded as of December 31, 2009 and 2008 was $7 million and $11 million, respectively, and is included in other deferred credits on the Comparative Balance Sheet. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are legal obligations associated with the retirement of those assets are separately accounted for as AROs.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 generating facilities with an aggregate facility net owned capacity of 1,158 MW. The FERC regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

Klamath Hydroelectric System – Klamath River, Oregon and California

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 170-MW Klamath hydroelectric system 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 operating under annual licenses until the relicensing process is complete or the system's four mainstem dams are removed. As part of the relicensing process, the FERC is required to perform an environmental review and in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. Prior to the FERC issuing a final license, PacifiCorp is required to obtain water quality certifications from Oregon and California. PacifiCorp currently has water quality applications pending in Oregon and California.

In November 2008, PacifiCorp signed a non-binding agreement in principle ("AIP") that laid out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward potential dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Subsequent to release of the AIP, negotiations between the parties continued with an expanded group of stakeholders. A final draft of the Klamath Hydroelectric Settlement Agreement ("KHSA") was released in January 2010 for public review. The parties to the KHSA, which include PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties, signed the KHSA in February 2010. Federal legislation to endorse and enact provisions of the KHSA is expected to be introduced in the United States Congress in 2010.

Under the terms of the KHSA, the United States Departments of the Interior and Commerce will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether removal of the Klamath hydroelectric system's four mainstem dams will advance restoration of the salmonid fisheries of the Klamath Basin and is in the public interest. This determination will be made by the United States Secretary of the Interior. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure. If dam removal costs exceed $200 million and if the State of California is unable to raise the funds necessary for dam removal costs, sufficient funds would need to be obtained elsewhere in order for the KHSA and dam removal to proceed.

Actual removal of a facility would occur only after all permits for removal are obtained and the facility and associated land are transferred to a dam removal entity. Prior to potential removal of a facility, the facility will generally continue to operate as it does currently. However, PacifiCorp is responsible for implementing interim measures to provide additional resource protections, water quality improvements, habitat enhancement for aquatic species and increased funding for hatchery operations in the Klamath River Basin.

In July 2009, Oregon's governor signed a bill authorizing PacifiCorp to collect surcharges from its Oregon customers for Oregon's share of the customer contribution for the cost of removing the Klamath hydroelectric system's four mainstem dams. On March 18, 2010, PacifiCorp filed with the OPUC to begin collecting the surcharge from Oregon customers, as of that date, subject to refund based on the OPUC's determination that the surcharges result in rates that are fair, just and reasonable. Also, in March 2010, PacifiCorp filed with the California Public Utilities Commission to collect a surcharge from PacifiCorp's California customers beginning January 1, 2011. The proceeds from the surcharges will be deposited in trust accounts to be established by each of the respective utility commissions.

As of December 31, 2009 and 2008, PacifiCorp had $67 million and $57 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction work in progress on the Comparative Balance Sheet.

Hydroelectric Commitments

As described above, certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $266 million over the next 10 years related to these licenses.

FERC Issues

FERC Investigation

During 2007, the Western Electricity Coordinating Council (the "WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation (the "NERC"). In April 2008, PacifiCorp received notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. Also in November 2008, in conjunction with the reliability standards review, the FERC assumed control of certain aspects of the WECC's 2007 audit. PacifiCorp has engaged in discussions with FERC staff regarding findings related to the WECC audit and the non-public investigation. However, PacifiCorp cannot predict the impact of the audit or the non-public investigation on its financial results at this time.

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants, excluding PacifiCorp, filed petitions in the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit concluded that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest, and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy in the Pacific Northwest spot market made by the California Energy Resources Scheduling ("CERS") division of the California Department of Water Resources. Without issuing the mandate order, the Ninth Circuit remanded the case to the FERC to (a) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings; (b) include sales to CERS in its analysis; and (c) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. In April 2009, the Ninth Circuit issued a formal mandate order, completing the remand of the case to the FERC, which has not yet undertaken further action. PacifiCorp cannot predict the future course of this proceeding and its impact on its financial results, if any, at this time.

Purchase Obligations

PacifiCorp has the following unconditional purchase obligations as of December 31, 2009 that are not reflected on the Comparative Balance Sheet. Minimum payments required for the years ending December 31 (in millions):

	2010	2011	2012	2013	2014	Thereafter	Total
Purchased electricity	$ 262	$ 165	$ 124	$ 127	$ 98	$ 596	$ 1,372
Fuel	554	366	225	213	207	1,198	2,763
Construction	677	172	32	7	18	99	1,005
Transmission	117	111	101	89	75	775	1,268
Operating leases	5	5	4	4	3	40	61
Other	107	29	10	10	6	43	205
Total commitments	$ 1,722	$ 848	$ 496	$ 450	$ 407	$ 2,751	$ 6,674

Purchased Electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in operation expenses on 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. These arrangements accounted for less than 5% of PacifiCorp's 2009 and 2008 energy sources.

Fuel

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

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. As of December 31, 2009, PacifiCorp had estimated long-term purchase obligations related to its construction program primarily for the installation of emissions control equipment, certain segments of the Energy Gateway Transmission Expansion Program and for new wind-powered generating facilities. Amounts included in the purchase obligations table above relate to firm commitments. The amounts described below include amounts to which PacifiCorp is not yet firmly committed through a purchase order or other agreement.

PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse resource areas, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area and the Western United States. Proposed transmission line segments are re-evaluated to ensure maximum benefits and timing before committing to move forward with permitting and construction. The first major transmission segment associated with this plan is expected to be placed in service during 2010, with other segments placed in service through 2019, depending on siting, permitting and construction schedules.

As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a number of commitments to the state regulatory commissions in all six states in which PacifiCorp has retail customers. These commitments are generally being implemented over several years following the acquisition and are subject to subsequent regulatory review and approval. As of December 31, 2009, the status of the key financial commitments was as follows:

- Invest approximately $812 million in emissions reduction technology for PacifiCorp's existing coal-fired generating facilities. Through December 31, 2009, PacifiCorp had spent a total of $865 million, including non-cash equity AFUDC, on these emissions reduction projects. During 2010, PacifiCorp expects to file notification of its completion of this commitment with the applicable state regulatory commissions.
- Invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization in an amount that was originally estimated to be approximately $520 million at the date of the acquisition. Through December 31, 2009, PacifiCorp had spent a total of $796 million in capital expenditures, including non-cash equity AFUDC, which was in excess of the original estimate due to the evolving nature of the projects agreed to in the commitment. This amount includes costs for the transmission expansion program discussed above.

Transmission

PacifiCorp has agreements for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Operating Leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the year 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.

Net rent expense was $21 million and $25 million during the years ended December 31, 2009 and 2008, respectively.

Other

PacifiCorp has purchase obligations related to equipment maintenance and various other service and maintenance agreements.

(14) Preferred Stock

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	2009 Shares	2009 Amount	2008 Shares	2008 Amount
Series:					
Serial Preferred, $100 stated value, 3,500 shares authorized					
4.52% to 4.72%	$102.3 to $103.5	157	$ 15	157	$ 15
5.00% to 5.40%	$100.0 to $101.0	108	10	108	10
6.00%	Non-redeemable	6	1	6	1
7.00%	Non-redeemable	18	2	18	2
5% Preferred, $100 stated value, 127 shares authorized	$110.0	126	13	126	13
		415	$ 41	415	$ 41

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. 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 not yet due for payment on preferred stock were $1 million as of December 31, 2009 and 2008.

(15) Common Shareholder's Equity

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized MEHC's March 2006 acquisition of PacifiCorp 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, 2009, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 47.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 46.25% for the year ending December 31, 2010, 45.25% for the year ending December 31, 2011 and 44% thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the March 2006 acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2009, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 51%, and PacifiCorp was permitted to dividend $928 million under this commitment.

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. As of December 31, 2009, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 8 and 9.

(16) Related-Party Transactions

Transactions with MEHC

PacifiCorp has an intercompany administrative services agreement with its indirect parent company, MEHC. Services provided by PacifiCorp and charged to affiliates relate primarily to administrative services, financial statement preparation and direct-assigned employees. Receivables associated with these activities were $- million and $1 million as of December 31, 2009 and 2008, respectively. Services provided by affiliates and charged to PacifiCorp relate primarily to the administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These expenses totaled $9 million during each of the years ended December 31, 2009 and 2008. Payables associated with these expenses were $2 million and $1 million as of December 31, 2009 and 2008, respectively.

PacifiCorp engages in various transactions with several of its affiliated companies in the ordinary course of business. Services provided by affiliates in the ordinary course of business and charged to PacifiCorp relate primarily to the transportation of natural gas and relocation services. These expenses totaled $3 million and $6 million during the years ended December 31, 2009 and 2008, respectively. Payables associated with these expenses were $1 million and $2 million as of December 31, 2009 and 2008, respectively.

PacifiCorp has long-term transportation contracts with Burlington Northern Santa Fe, LLC ("BNSF"), a wholly owned subsidiary of Berkshire Hathaway and PacifiCorp's ultimate parent company. Transportation costs under these contracts were $29 million and $32 million during the years ended December 31, 2009 and 2008, respectively. As of December 31, 2009 and 2008, PacifiCorp had $1 million and $2 million, respectively, of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participates 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, 2010. Premium expenses were $7 million during each of the years ended December 31, 2009 and 2008. Prepayments to MISL were $2 million as of December 31, 2009 and 2008. Receivables for claims were $10 million and $7 million as of December 31, 2009 and 2008, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2009 and 2008, income taxes receivable from MEHC were $249 million and $42 million, respectively.

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 relate primarily to management services, income taxes and labor. These receivables were $4 million and $1 million as of December 31, 2009 and 2008, respectively. Services provided by subsidiaries and charged to PacifiCorp primarily relate to coal purchases. These payables were $10 million and $14 million as of December 31, 2009 and 2008, respectively. Expenses for these coal purchases were $126 million and $123 million during the years ended December 31, 2009 and 2008, respectively.

PacifiCorp is party to an umbrella loan agreement with one subsidiary. Regulatory authorizations permit PacifiCorp to loan up to $30 million each to certain subsidiaries and to borrow from each of these subsidiaries, 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, 2009 and 2008, advances by PacifiCorp under the terms of the umbrella loan agreement were $5 million and $21 million, respectively, including interest.

(17) Supplemental Cash Flows Information

The summary of supplemental cash flows information is as follows for the years ended December 31 (in millions):

	2009	2008
Interest paid, net of amounts capitalized	$ 322	$ 280
Income taxes (received) paid, net	$ (248)	$ (52)
Supplemental disclosure of non-cash investing and financing activities:		
Utility plant additions in accounts payable	$ 240	$ 398
Utility plant additions acquired under capital lease obligations	$ -	$ 17

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	40,954			(3,557,338)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	(171,723)			1,137,427
4	Total (lines 2 and 3)	(171,723)			1,137,427
5	Balance of Account 219 at End of Preceding Quarter/Year	(130,769)			(2,419,911)
6	Balance of Account 219 at Beginning of Current Year	(130,769)			(2,419,911)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	191,182			
8	Current Quarter/Year to Date Changes in Fair Value	(60,413)			(3,399,666)
9	Total (lines 7 and 8)	130,769			(3,399,666)
10	Balance of Account 219 at End of Current Quarter/Year				(5,819,577)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(3,516,384)		
2					
3			965,704		
4			965,704	458,282,904	459,248,608
5			(2,550,680)		
6			(2,550,680)		
7			191,182		
8			(3,460,079)		
9			(3,268,897)	541,846,446	538,577,549
10			(5,819,577)		

FOOTNOTE DATA

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

Unrealized loss on available-for-sale securities of ($210,751) less tax of $79,982 netting to ($130,769).

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

Unrecognized amounts on retirement benefits of ($3,900,000) less tax of $1,480,089 netting to ($2,419,911).

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

Unrecognized amounts on retirement benefits of ($9,379,000) less tax of $3,559,423 netting to ($5,819,577).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	19,527,440,207	19,527,440,207
4	Property Under Capital Leases	65,393,121	65,393,121
5	Plant Purchased or Sold	3,003,416	3,003,416
6	Completed Construction not Classified	115,125,119	115,125,119
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	19,710,961,863	19,710,961,863
9	Leased to Others		
10	Held for Future Use	13,674,549	13,674,549
11	Construction Work in Progress	1,799,367,394	1,799,367,394
12	Acquisition Adjustments	157,193,780	157,193,780
13	Total Utility Plant (8 thru 12)	21,681,197,586	21,681,197,586
14	Accum Prov for Depr, Amort, & Depl	7,199,824,404	7,199,824,404
15	Net Utility Plant (13 less 14)	14,481,373,182	14,481,373,182
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,663,897,531	6,663,897,531
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	439,600,000	439,600,000
22	Total In Service (18 thru 21)	7,103,497,531	7,103,497,531
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	96,326,873	96,326,873
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,199,824,404	7,199,824,404

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
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					28
					29
					30
					31
					32
					33

FOOTNOTE DATA

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

Depreciation is comprised of:

Depreciation	$6,627,761,298
Depletion	36,136,233
Total	$6,663,897,531

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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		
3	(302) Franchises and Consents	162,091,776	436,147
4	(303) Miscellaneous Intangible Plant	559,153,929	32,932,340
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	721,245,705	33,368,487
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	95,846,500	33,153
9	(311) Structures and Improvements	815,948,688	24,753,054
10	(312) Boiler Plant Equipment	2,979,007,633	189,279,669
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	804,355,376	37,474,088
13	(315) Accessory Electric Equipment	362,445,428	5,090,565
14	(316) Misc. Power Plant Equipment	26,460,892	3,243,121
15	(317) Asset Retirement Costs for Steam Production	27,254,154	13,455,007
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,111,318,671	273,328,657
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	19,692,835	522,905
28	(331) Structures and Improvements	87,066,858	15,856,905
29	(332) Reservoirs, Dams, and Waterways	296,190,974	21,260,450
30	(333) Water Wheels, Turbines, and Generators	102,877,058	12,718,272
31	(334) Accessory Electric Equipment	52,221,914	5,021,272
32	(335) Misc. Power PLant Equipment	2,377,969	901
33	(336) Roads, Railroads, and Bridges	14,727,440	1,473,655
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	575,155,048	56,854,360
36	D. Other Production Plant		
37	(340) Land and Land Rights	21,542,917	
38	(341) Structures and Improvements	108,191,405	2,017,510
39	(342) Fuel Holders, Products, and Accessories	9,194,264	
40	(343) Prime Movers	1,638,219,095	580,375,255
41	(344) Generators	235,221,712	2,672,868
42	(345) Accessory Electric Equipment	135,044,678	1,623,312
43	(346) Misc. Power Plant Equipment	7,184,019	
44	(347) Asset Retirement Costs for Other Production	2,038,672	1,303,845
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,156,636,762	587,992,790
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	7,843,110,481	918,175,807

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			162,527,923		3
17,626,119		15,447,697	589,907,847		4
17,626,119		15,447,697	752,435,770		5
					6
					7
			95,879,653		8
3,270,654		1,148,487	838,579,575		9
41,687,173		-2,532,123	3,124,068,006		10
					11
10,035,118		1,075,830	832,870,176		12
805,282		161,756	366,892,467		13
641,258		146,050	29,208,805		14
1,670,586	-1,718,760		37,319,815		15
58,110,071	-1,718,760		5,324,818,497		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
369		-5,757	20,209,614		27
415,668		1,809,322	104,317,417		28
627,879		-2,005,625	314,817,920		29
1,754,844		-2,403,951	111,436,535		30
865,609		2,663,277	59,040,854		31
25,810		38,067	2,391,127		32
223,812		-35,047	15,942,236		33
					34
3,913,991		60,286	628,155,703		35
					36
		1,973,791	23,516,708		37
37,255		45,277,745	155,449,405		38
		1,617,410	10,811,674		39
18,494,425		75,986,169	2,276,086,094		40
		109,644,532	347,539,112		41
39,889		93,593,961	230,222,062		42
		4,995,666	12,179,685		43
		689,117	4,031,634		44
18,571,569		333,778,391	3,059,836,374		45
80,595,631	-1,718,760	333,838,677	9,012,810,574		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	04/14/2010	End of 2009/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	95,350,555	3,675,164
49	(352) Structures and Improvements	70,696,617	4,945,391
50	(353) Station Equipment	1,148,864,289	168,201,623
51	(354) Towers and Fixtures	433,558,992	46,195,433
52	(355) Poles and Fixtures	553,638,259	32,204,534
53	(356) Overhead Conductors and Devices	730,267,034	35,261,518
54	(357) Underground Conduit	3,209,582	2,246
55	(358) Underground Conductors and Devices	7,490,175	39,549
56	(359) Roads and Trails	11,453,447	79,954
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	3,054,528,950	290,605,412
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	46,526,763	5,439,651
61	(361) Structures and Improvements	58,354,467	304,432
62	(362) Station Equipment	731,786,998	69,434,219
63	(363) Storage Battery Equipment	1,457,804	
64	(364) Poles, Towers, and Fixtures	873,534,943	41,600,184
65	(365) Overhead Conductors and Devices	620,174,971	16,500,354
66	(366) Underground Conduit	279,913,506	13,471,362
67	(367) Underground Conductors and Devices	677,463,735	25,162,081
68	(368) Line Transformers	1,023,120,299	47,892,005
69	(369) Services	535,288,103	25,352,511
70	(370) Meters	187,558,731	8,253,578
71	(371) Installations on Customer Premises	8,813,849	65,164
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	61,496,138	1,904,514
74	(374) Asset Retirement Costs for Distribution Plant	499,185	1,437,860
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,105,989,492	256,817,915
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	16,094,266	
87	(390) Structures and Improvements	229,487,385	3,645,149
88	(391) Office Furniture and Equipment	89,052,008	16,452,054
89	(392) Transportation Equipment	99,362,782	6,266,070
90	(393) Stores Equipment	13,644,340	519,740
91	(394) Tools, Shop and Garage Equipment	62,760,306	2,336,006
92	(395) Laboratory Equipment	38,973,211	1,309,776
93	(396) Power Operated Equipment	126,473,492	9,949,554
94	(397) Communication Equipment	241,911,600	24,704,180
95	(398) Miscellaneous Equipment	6,357,082	624,360
96	SUBTOTAL (Enter Total of lines 86 thru 95)	924,116,472	65,806,889
97	(399) Other Tangible Property	273,092,913	10,051,544
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,197,249,133	75,858,433
100	TOTAL (Accounts 101 and 106)	17,922,123,761	1,574,826,054
101	(102) Electric Plant Purchased (See Instr. 8)	302,819,070	3,003,416
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	18,224,942,831	1,577,829,470

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
249,764		2,285,083	101,061,038		48
119,438		10,843,762	86,366,332		49
7,259,384		-2,859,155	1,306,947,373		50
655,458		1,149,469	480,248,436		51
2,369,670		-42,204	583,430,919		52
1,836,417		-1,108,932	762,583,203		53
			3,211,828		54
			7,529,724		55
		1,667	11,535,068		56
					57
12,490,131		10,269,690	3,342,913,921		58
					59
3,775		445,310	52,407,949		60
114,063		7,981,769	66,526,605		61
3,737,013		-8,569,947	788,914,257		62
			1,457,804		63
5,789,008			909,346,119		64
3,068,657		-54,768	633,551,900		65
1,194,825		9,980	292,200,023		66
1,514,900			701,110,916		67
8,063,176			1,062,949,128		68
877,512			559,763,102		69
8,591,513		-11,180	187,209,616		70
69,893			8,809,120		71
					72
1,009,400			62,391,252		73
			1,937,045		74
34,033,735		-198,836	5,328,574,836		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		106,129	16,200,395		86
1,766,143		160,936	231,527,327		87
24,307,943		142,615	81,338,734		88
5,380,345		-102,299	100,146,208		89
356,794		92,703	13,899,989		90
2,354,374		-24,302	62,717,636		91
3,261,240		67,056	37,088,803		92
4,958,902		-38,763	131,425,381		93
21,468,866		1,035,122	246,182,036		94
220,260		54,828	6,816,010		95
64,074,867		1,494,025	927,342,519		96
4,818,201		121,702	278,447,958		97
			39,748		98
68,893,068		1,615,727	1,205,830,225		99
213,638,684	-1,718,760	360,972,955	19,642,565,326		100
		302,819,070	3,003,416		101
					102
					103
213,638,684	-1,718,760	58,153,885	19,645,568,742		104

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

Account	Description	Balance Beginning of Year	Additions	Retirements	Adjustments	Balance at End of Year
	(a)	(b)	(c)	(d)	(e)	(g)
39921	Land Owned in Fee	$ 2,634,916	$ -	$ -	$ -	$ 2,634,916
39922	Land Rights	52,550,647	-	-	-	52,550,647
39930	Structures	40,385,161	66,472	(2,017)	191,550	40,641,166
39941	Surface - Plant Equipment	12,180,880	-	(24,376)	-	12,156,504
39944	Surface - Electric Power Facilities	3,424,575	-	-	-	3,424,575
39945	Underground - Coal Mine Equipment	65,527,839	6,644,746	(2,488,958)	-	69,683,627
39946	Longwall Shields	17,699,562	-	-	-	17,699,562
39947	Longwall Equipment	10,652,772	-	-	-	10,652,772
39948	Mainline Extension	17,001,312	1,522,774	(549,041)	-	17,975,045
39949	Section Extension	4,695,073	758,777	(1,556,936)	-	3,896,914
39951	Vehicles	1,180,419	8,500	(46,030)	121,702	1,264,591
39952	Heavy Construction Equipment	5,160,806	10,801	(11,914)	-	5,159,693
39960	Miscellaneous General Equipment	2,117,020	333,480	(116,122)	(169,377)	2,165,001
39961	Computers - Mainframe	615,912	(2,661)	(22,807)	(22,173)	568,271
39970	Mine Development and Road Extension	36,839,783	708,655	-	-	37,548,438
399915	Coal Mine Asset Retirement Obligations	426,236	-	-	-	426,236
	Total Plant Used in Mining Activities	$ 273,092,913	$ 10,051,544	$ (4,818,201)	$ 121,702	$ 278,447,958

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.: 101 Column: c

In August 2009, PacifiCorp received FERC approval in Docket Nos. EC09-86-000 and EC09-86-001, pursuant to section 203 of the Federal Power Act, for the acquisition of a portion of a 69-kilovolt ("kV") electric transmission facility from Garkane Energy Cooperative, Inc. The acquisition was completed in September 2009. The purchase included electric transmission line facilities from, and including, the interconnect point at the Clifton Wilson substation located in Hurricane, Utah to the Twin Cities substation located in Hildale, Utah. In February 2010, the FERC approved the journal entries called for by the Uniform System of Accounts in Docket No. AC10-44-000. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold and recorded the purchase to the appropriate plant accounts.

Schedule Page: 204 Line No.: 101 Column: f

On September 15, 2008, after having received the requisite regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC ("Chehalis"), an entity owning a 520-megawatt ("MW") natural gas-fired generating facility located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the facility, which was included in account 102, Electric plant purchased or sold. Chehalis was merged into PacifiCorp immediately following the acquisition. The results of the facility's operations have been included in PacifiCorp's financial statements since the acquisition date. In May 2009, the Federal Energy Regulatory Commission approved the journal entries called for by the Uniform System of Accounts, with modifications to the purchase accounting adjustments for asset retirement obligations. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold and recorded the purchase to the appropriate plant accounts. Refer to page 108, *Important Changes During the Year,* Item 2, of this Form No. 1 for further discussion.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	North Horn Mountain Coal Properties	1977	2015-2020	953,014
4	Barnes Butte Substation	2007	2013	746,268
5	Wild Horse Wind Plant	2007	2017	6,763,094
6	Twelve Mile Wind Plant	2007	2017	2,160,207
7	Jumbers Point Substation	2008	2015	1,173,276
8	Mountain Green Substation	2009	2013	281,758
9	Hoggard Substation	2009	2010-2025	880,553
10				
11	Miscellaneous, each under $250,000:			716,379
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
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33				
34				
35				
36				
37				
38				
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40				
41				
42				
43				
44				
45				
46				
47	Total			13,674,549

FOOTNOTE DATA

Schedule Page: 214 Line No.: 3 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.: 5 Column: c

Land purchased for wind farms with an estimated construction date of 2017 or before subject to the timing of completion of the Energy Gateway Transmission Expansion Project.

Schedule Page: 214 Line No.: 6 Column: c

Land purchased for wind farms with an estimated construction date of 2017 or before subject to the timing of completion of the Energy Gateway Transmission Expansion Project.

Schedule Page: 214 Line No.: 11 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	04/14/2010	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Intangible:	
2	Klamath River System Relicensing	66,907,218
3	C&T TrIP II Energy Trading Systems	4,296,447
4	SAP license and maintenance enhancements	2,406,070
5	CY09 MS Office and Windows TOM	1,240,898
6		
7	Production:	
8	Dave Johnston U3 SO2 & PM Emission Control Upgrades	262,088,428
9	Dunlap Ranch I Wind Plant (111 MW)	97,821,911
10	Dave Johnston U4 SO2 & PM Emission Control Upgrades	70,299,477
11	Naughton U2 Flue Gas Desulfurization System	42,358,741
12	Naughton U1 Flue Gas Desulfurization System	33,583,859
13	Huntington U1 Clean Air - PM	33,479,214
14	Lewis River System Relicensing Implementation	17,919,864
15	Hunter U2 Clean Air-PM	17,094,809
16	Wyodak U1 SO2 and PM Emission Control Upgrade	16,836,533
17	Hunter U1 Turbine Upgrade HP/IP/LP	16,132,380
18	Blundell U3 Project	14,719,647
19	North Umpqua River System Relicensing Implementation	15,137,164
20	Jim Bridger U1 SO2 & PM Emission Control Upgrades	8,211,822
21	Huntington U1 SO2 & PM Emission Control Upgrades	7,414,348
22	Jim Bridger U1 Turbine Upgrade HP/IP/LP	6,980,920
23	Huntington Water Efficiency Management	4,953,348
24	Jim Bridger U3 SO2 & PM Emission Control Upgrades	4,683,825
25	Dave Johnston U3 - Replace Boiler/Turbine Controls	4,473,082
26	Hunter U1 Main Controls Replacement	4,316,284
27	Jim Bridger U1 Reheater Replacement 10	4,160,800
28	Dave Johnston U3 Low NOx Burners	3,738,728
29	Huntington U1 Turbine Upgrade HP/IP/LP	3,716,010
30	Hunter U1 Economizer Replacement	3,563,421
31	Hunter U2 Turbine Upgrade HP/IP/LP	3,234,158
32	Huntington U2 Steam Coil Air Preheaters	3,151,162
33	Huntington U1 Economizer Replacement	3,098,384
34	Hayden Coal Unloading Facility	2,720,313
35	Ashton Dam Seepage Control	2,710,865
36	Hunter U1 Low Temp. SH Replacement	2,645,673
37	Jim Bridger U1 Generator Rewind	2,286,906
38	Jim Bridger NERC/CIPS Compliance Work	2,021,987
39	Huntington U2 Turbine Upgrade HP/IP/LP	1,900,057
40	Hunter U3 Turbine Upgrade HP/IP/LP	1,821,121
41	Hunter U1 SO2 & PM Emission Control Upgrades	1,778,231
42	Jim Bridger U3 Turbine Upgrade HP/IP/LP	1,667,653
43	TOTAL	1,799,367,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Jim Bridger U4 Turbine Upgrade HP/IP/LP	1,631,217
2	Gadsby NERC/CIPS Compliance Work	1,619,747
3	Jim Bridger U2 Turbine Upgrade HP/IP/LP	1,609,899
4	Jim Bridger U1 Clean Air - NOx	1,596,678
5	Rogue River System Relicensing Implementation	1,583,989
6	Huntington NERC/CIPS Compliance Work	1,517,536
7	Dave Johnston U3 - Horizontal SH Replace	1,372,507
8	Currant Creek Block 2 Development	1,302,690
9	Dave Johnston NERC/CIPS Compliance Work	1,273,641
10	Currant Creek NERC/CIPS Compliance Work	1,264,948
11	Hunter U2 Main Controls Replacement	1,246,758
12	Hunter U2 Economizer Replacement	1,185,291
13	Hunter U2 SO2 & PM Emission Control Upgrades	1,182,674
14	Dave Johnston U3 - SSH Assembly/Header Replace	1,154,187
15	Lake Side Block 2 Development	1,150,254
16	Huntington U1 Clean Air - NOx	1,147,695
17	Wyodak NERC/CIPS Compliance Work	1,135,414
18	Bear River System Relicensing Implementation	1,209,691
19	Hunter NERC/CIPS Compliance Work	1,093,540
20	Hunter Cond Pol/WT/Ash DCS Replacements	1,091,264
21	Jim Bridger U1 APH Baskets 10	1,081,682
22	Swift Slope Stabilization (East Slope)	1,040,165
23	Carbon NERC/CIPS Compliance Work	1,024,744
24	Colstrip U3-U4: Mercury Control	1,017,875
25	Hunter U2 Low Temp. SH Replacement	1,004,336
26		
27	Transmission:	
28	Populus-Terminal: Dbl Ckt 345 kV Transmission Line	623,130,078
29	Three Peaks Sub: Install 345 kV Sub	35,784,861
30	Dave Johnston Bridger Midpoint 500kV Line	28,965,992
31	St George-Red Butte 138kV Line	19,048,921
32	Mona-Oquirrh Line	16,982,292
33	Bridger Mona 500kV Line	14,445,374
34	90 South-CW 345kV Line Double Circuit	9,474,814
35	Line 37 Conv to 115kV Bld Nickel Mt Sub	7,963,713
36	Upper Green River Basin - Jonah Field & Paradise Subs/Lines	7,501,436
37	Dave Johnston to Casper 230kV No 1&2 Line Rebuild	6,795,527
38	Malin Sub Series Capacitor Replacement	3,272,341
39	Maintain TOT 4A-4B Transmission Capability	2,593,564
40	Oquirrh Terminal 345kV Line	2,293,063
41	Parrish Gap Const New 230-69kV Sub	2,255,824
42	Pinto Sub 345kV Series Capacitors	2,146,989
43	TOTAL	1,799,367,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	California-Oregon Intertie Transfer Capability Incr	2,094,552
2	Wallula McNary 230kV Line	1,922,536
3	Vickers Sub Add 46kV Circuit Breakers	1,253,290
4	West Point-New 138 kV Line & 40 MVA Sub	1,211,660
5	Southwest WY Silver Creek Build 138kV Line	1,204,429
6	Line 88 - 115kV Jerome Prairie to Cave Junction	1,093,077
7	Outlook Sub Add 115kV Circuit Breaker	1,057,630
8	Dunlap Ranch I Wind Plant Ph1 Intercn Q203	1,053,950
9	Chappel Creek 230kV Cimarex Energy	1,009,830
10		
11	Distribution:	
12	Dowell Sub Const New 115kV Substation	4,477,613
13	Saratoga Sub Add 2nd Trnsf Rebld Tran Jumper	3,504,281
14	Northeast Instl 2nd 4-12kV Trnsf 4-12kV	3,389,293
15	Texum Sub Rebld & Incr Capacity 25MVA	3,313,371
16	Community Park Sub Conv to 115-12 5kV	2,617,621
17	Copper Hills New 138-12 5kV Sub	2,581,075
18	Stevens Road Sub Add 2nd Xfmr & 3rd Fdr	2,466,443
19	City Creek Ctr New 40 MW Dev for PRI	2,133,261
20	Skypark Build New 138-12.5kV Substation	1,980,565
21	Tamarisk New 138-12.5kV Sub	1,137,847
22	Smithfield Substation Add New Feeder 13	1,075,436
23		
24	General:	
25	Mobile Radio Replacement Project	18,805,636
26	Deer Creek Mine-Reconstruct Longwall System	5,663,156
27	Mobile Radio Purch-Implement VHF Spectrum	2,737,187
28	Control Center Disaster Recovery Imprv Ph 2	2,056,968
29	PCC/SCC Router Replacement TOM	1,647,926
30	IP Telephony Project	1,190,841
31	Deer Creek Mine-(1) 60" Terminal Group	1,067,995
32		
33	Miscellaneous projects each under $1,000,000	113,854,956
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,799,367,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	6,343,121,197	6,343,121,197		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	473,163,461	473,163,461		
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):	27,072,473	27,072,473		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	500,235,934	500,235,934		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	195,151,937	195,151,937		
13	Cost of Removal	50,740,495	50,740,495		
14	Salvage (Credit)	5,823,180	5,823,180		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	240,069,252	240,069,252		
16	Other Debit or Cr. Items (Describe, details in footnote):	60,609,652	60,609,652		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	6,663,897,531	6,663,897,531		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,512,694,439	2,512,694,439		
21	Nuclear Production				
22	Hydraulic Production-Conventional	251,713,352	251,713,352		
23	Hydraulic Production-Pumped Storage				
24	Other Production	285,159,398	285,159,398		
25	Transmission	1,142,839,345	1,142,839,345		
26	Distribution	2,003,524,851	2,003,524,851		
27	Regional Transmission and Market Operation				
28	General	467,966,146	467,966,146		
29	TOTAL (Enter Total of lines 20 thru 28)	6,663,897,531	6,663,897,531		

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 - until consumed	$	10,454,473
Account 143.3 Joint Owner Receivable - Depreciation expense billed to Joint Owners		233,947
Account 182.3 Other Regulatory Assets		1,220,290
Vehicle Depreciation allocated to O&M based on usage activity		13,886,246
Account 503.1 Blundell Depletion		185,368
Account 503 IGC Depreciation and Amortization		1,092,149
Total Other Accounts	$	27,072,473

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

Chehalis plant transfer from account 102 Electric plant purchased or sold	$	53,162,249
Other items including:		7,447,403

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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 MINERALS, INC	12/31/1991		
2	Common Stock			1
3	Capital Contributions			47,960,000
4	Undistributed Earnings			102,321,791
5	SUBTOTAL			150,281,792
6				
7	PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY	8/19/1994		
8	Common Stock			1,000,000
9	Capital Contributions			13,719,625
10	Undistributed Subsidiary Earnings			6,518,730
11	SUBTOTAL			21,238,355
12				
13	PACIFICORP FUTURE GENERATIONS, INC	9/19/1999		
14	Undistributed Subsidiary Earnings			-9,952
15	SUBTOTAL			-9,952
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
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34				
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36				
37				
38				
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41				
42	Total Cost of Account 123.1 $ 62,679,626		TOTAL	171,510,195

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
		1		2
		47,960,000		3
11,386,280		113,708,071		4
11,386,280		161,668,072		5
				6
				7
		1,000,000		8
		13,719,625		9
1,811,740		8,330,470		10
1,811,740		23,050,095		11
				12
				13
			-9,952	14
			-9,952	15
				16
				17
				18
				19
				20
				21
				22
				23
				24
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				41
13,198,020		184,718,167	-9,952	42

FOOTNOTE DATA

Schedule Page: 224 Line No.: 4 Column: e

Pacific Minerals, Inc. ("PMI") is a wholly owned subsidiary of PacifiCorp that holds a 66.67% ownership interest in Bridger Coal Company, a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company. Equity earnings on PacifiCorp's investment in PMI represent intercompany profit in Bridger Coal Company's sales of coal to PacifiCorp. Such amounts are not recorded in account 418.1 Equity in Earnings of Subsidiary Companies. Rather, PacifiCorp records PMI's earnings before interest and taxes as an offset to fuel inventory, which is charged to fuel expense as consumed, and records interest and taxes in their respective line items.

Schedule Page: 224 Line No.: 14 Column: h

Effective December 31, 2009, PacifiCorp Future Generations, Inc. and its subsidiary Canopy Botanicals, Inc. were dissolved.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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)	136,802,882	170,930,143	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)	76,746,318	69,236,794	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	71,228,040	87,614,292	Electric
8	Transmission Plant (Estimated)	497,646	838,582	Electric
9	Distribution Plant (Estimated)	16,772,938	16,134,398	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	4,830,427	4,322,956	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	170,075,369	178,147,022	
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)	306,878,251	349,077,165	

FOOTNOTE DATA

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

Mining M&S	$4,656,652
General Plant M&S	173,775
	$4,830,427

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

Mining M&S	$4,170,119
General Plant M&S	152,837
	$4,322,956

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2010	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	146,822.00		144,002.00	
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	72,371.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	See footnote for details	47,500.00			
23					
24					
25					
26					
27					
28	Total	47,500.00			
29	Balance-End of Year	26,951.00		144,002.00	
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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2011		2012		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
156,646.00		156,647.00		4,035,432.00		4,639,549.00		1
								2
								3
				156,644.00		156,644.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						72,371.00		18
								19
								20
								21
						47,500.00		22
								23
								24
								25
								26
								27
						47,500.00		28
156,646.00		156,647.00		4,192,076.00		4,676,322.00		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

FOOTNOTE DATA

Schedule Page: 228 Line No.: 22 Column: b

The names of purchasers/transferees and the number of allowances disposed of in the current year are provided below.

Vitol, Inc.	18,000
NRG Power Marketing LLC	10,000
Koch Supply and Trading, LP	7,500
Edison Mission Marketing and Trading, Inc.	5,000
Ohio Valley Electric Corporation	2,500
CE2 Environmental Opportunities I LP	1,250
CE2 Environmental Markets LP	1,250
Shell Energy North America (US), LP	1,000
AES Deepwater, Inc.	1,000
	47,500

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	Unrecovered Plant: Trojan Nuclear	3,479,179		407	1,670,007	1,809,172
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: Powerdale	6,959,922		407	3,479,961	3,479,961
30	Hydro Electric Plant					
31	Date of Retirement: 02/08/2007					
32	Date of Commission Authorization:					
33	05/14/2007					
34	Amortization Period: 05/2007					
35	through 12/2010					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	10,439,101			5,149,968	5,289,133

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	See Footnote	6,598	5616000	6,598	4562000
3	Aref 557400	14,459	5616000	14,459	4562000
4	Aref 558590	3,195	5616000	3,195	4562000
5	Aref 508134	100	5616000		
6	Aref 523183	873	5616000		
7	Aref 531024	2,603	5616000		
8	Aref 527444, 527445, 527464	824	5616000		
9	Aref 526124	1,826	5616000		
10	Aref 526123	1,366	5616000		
11	Aref 546410	15,044	5616000		
12	Aref 560666	4,892	5616000		
13	Aref 563056	4,835	5616000		
14	Aref 567900	6,210	5616000		
15	Aref 575862	5,391	5616000		
16	Aref 578260	3,629	5616000		
17	Aref 581025	3,541	5616000		
18	Customer Studies Accruals	1,285	5616000		
19	Aref 495604	100	1070000		
20	Aref 516316	393	1070000		
21	**Generation Studies**				
22	GIQ0102	1,222	5617000	1,222	4562000
23	GIQ0093	960	5617000	960	4562000
24	GIQ0169	60	5617000	60	4562000
25	GIQ0190	523	5617000	523	4562000
26	GIQ0128	13,503	5617000	13,503	4562000
27	GIQ0194	360	5617000	360	4562000
28	GIQ0197	811	5617000	811	4562000
29	GIQ0210	2,987	5617000	2,987	4562000
30	GIQ0130	913	5617000	913	4562000
31	GIQ0220	629	5617000	629	4562000
32	GIQ0148	144	5617000	144	4562000
33	GIQ0135	2,040	5617000	2,040	4562000
34	GIQ0136	626	5617000	626	4562000
35	GIQ0137	1,505	5617000	1,505	4562000
36	GIQ0208	888	5617000	888	4562000
37	GIQ0153	435	5617000	435	4562000
38	GIQ0175	530	5617000	688	4562000
39	GIQ0229	9,716	5617000	9,716	4562000
40	GIQ0231	17,374	5617000	17,374	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Aref 530263	4,832	1070000		
3	Aref 495604	8,783	1070000		
4	Aref 531617	251	1070000		
5	Aref 541087	6,635	1070000		
6	Aref 540950	4,000	1070000		
7	Aref 548695	4,065	1070000		
8	Aref 552990	3,119	1070000		
9	Aref 554206	7,004	1070000		
10	Aref 578305	4,502	1070000		
11	Aref 575662	3,587	1070000		
12	Aref 575869	3,811	1070000		
13	Aref 583614	1,337	1070000		
14	Aref 583608	1,228	1070000		
15					
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21	**Generation Studies**				
22	GIQ0152	1,386	5617000	1,386	4562000
23	GIQ0016	13,606	5617000	13,606	4562000
24	GIQ0154	321	5617000	321	4562000
25	GIQ0172	392	5617000	392	4562000
26	GIQ0173	284	5617000	284	4562000
27	GIQ0178	247	5617000	247	4562000
28	GIQ0235	5,781	5617000	5,781	4562000
29	GIQ0239	74	5617000	74	4562000
30	GIQ0238	1,366	5617000	1,366	4562000
31	GIQ0174	4,471	5617000	4,471	4562000
32	GIQ0187	1,085	5617000	1,085	4562000
33	GIQ0188	2,946	5617000	2,946	4562000
34	GIQ0189	46	5617000	46	4562000
35	GIQ0193	4,319	5617000	4,319	4562000
36	GIQ0218	8,287	5617000	8,287	4562000
37	GIQ0221	2,838	5617000	2,838	4562000
38	GIQ0240	11,250	5617000	11,250	4562000
39	GIQ0208	1,321	5617000	1,321	4562000
40	GIQ0241	1,799	5617000	1,799	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	GIQ0225	18,722	5617000	18,722	4562000
23	GIQ0226	12,138	5617000	12,138	4562000
24	GIQ0246	5,964	5617000	5,964	4562000
25	GIQ0247	5,052	5617000	5,052	4562000
26	GIQ0249	3,000	5617000	3,000	4562000
27	GIQ0242	279	5617000	279	4562000
28	GIQ0171	4,266	5617000	4,266	4562000
29	GIQ0217	1,672	5617000	1,672	4562000
30	GIQ0198	5,953	5617000	5,653	4562000
31	GIQ0200	7,052	5617000	7,052	4562000
32	GIQ0201	7,122	5617000	7,122	4562000
33	GIQ0230	17,783	5617000	11,297	4562000
34	GIQ0228	11,575	5617000	11,575	4562000
35	GIQ0234	20,973	5617000	20,973	4562000
36	GIQ0248	12,737	5617000	12,737	4562000
37	GIQ0236	3,339	5617000	3,339	4562000
38	GIQ0199	32,205	5617000	32,205	4562000
39	GIQ0244	4,057	5617000	4,057	4562000
40	GIQ0250	10,559	5617000	10,559	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	GIQ0209	6,742	5617000	6,742	4562000
23	GIQ0251	2,139	5617000	2,139	4562000
24	GIQ0252	2,133	5617000	2,133	4562000
25	GIQ0253	355	5617000	355	4562000
26	GIQ0243	20,914	5617000	20,914	4562000
27	GIQ0220	15,486	5617000	15,486	4562000
28	GIQ0178	14,655	5617000	14,655	4562000
29	GIQ0191	4,336	5617000	4,336	4562000
30	GIQ0254	3,538	5617000	3,538	4562000
31	GIQ0175	4,680	5617000	4,680	4562000
32	GIQ0255	1,085	5617000	1,085	4562000
33	GIQ0229	12,499	5617000	12,499	4562000
34	GIQ0256	7,143	5617000	7,143	4562000
35	GIQ0258	43,220	5617000	43,220	4562000
36	GIQ1100	5,780	5617000	5,780	4562000
37	GIQ0257	11,121	5617000	11,121	4562000
38	GIQ0240	74	5617000	74	4562000
39	GIQ0190	13,312	5617000	13,312	4562000
40	GIQ0255	14,976	5617000	14,976	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	GIQ0259	4,879	5617000	4,879	4562000
23	GIQ0259	2,721	5617000	911	4562000
24	GIQ0260	8,136	5617000	8,136	4562000
25	GIQ0225	8,817	5617000	8,817	4562000
26	GIQ0226	6,427	5617000	6,427	4562000
27	GIQ0247	32,486	5617000	32,486	4562000
28	GIQ0238	4,648	5617000	4,648	4562000
29	GIQ0197	5,754	5617000	5,754	4562000
30	GIQ0234	14,343	5617000	14,343	4562000
31	GIQ0266	4,387	5617000	3,950	4562000
32	GIQ0257	1,274	5617000	1,274	4562000
33	GIQ0269	11,005	5617000	11,005	4562000
34	GIQ0249	6,350	5617000	6,350	4562000
35	GIQ0254	24,664	5617000	24,664	4562000
36	GIQ0268	7,948	5617000	7,948	4562000
37	GIQ0243	13,050	5617000	13,050	4562000
38	GIQ0273	3,252	5617000	3,252	4562000
39	GIQ0174	144	5617000	144	4562000
40	GIQ0145	(576)	5617000	(576)	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	GIQ0145	1,847	5617000		4562000
23	GIQ0184	808	5617000		4562000
24	GIQ0260	12,209	5617000	12,209	4562000
25	GIQ0274	8,701	5617000	8,701	4562000
26	GIQ0275	5,898	5617000	5,898	4562000
27	GIQ0276	3,247	5617000	3,247	4562000
28	GIQ0277	7,157	5617000	7,157	4562000
29	GIQ0247	7,030	5617000	7,030	4562000
30	GIQ0278	3,653	5617000	3,653	4562000
31	GIQ0279	8,354	5617000	8,354	4562000
32	GIQ0280	2,412	5617000	2,412	4562000
33	GIQ0248	9,177	5617000	9,177	4562000
34	GIQ0269	5,891	5617000	5,891	4562000
35	GIQ0283	3,441	5617000	3,441	4562000
36	GIQ0281	1,704	5617000	1,704	4562000
37	GIQ0282	1,293	5617000	1,293	4562000
38	GIQ0255	2,716	5617000	2,716	4562000
39	GIQ0285	769	5617000	769	4562000
40	GIQ0286	1,376	5617000	1,376	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
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21	**Generation Studies**				
22	GIQ0287	9,652	5617000	9,652	4562000
23	GIQ0288	2,000	5617000	2,000	4562000
24	GIQ0289	6,205	5617000	6,205	4562000
25	GIQ0290	5,028	5617000	5,028	4562000
26	GIQ0268	10,748	5617000	10,748	4562000
27	GIQ0291	7,106	5617000	7,106	4562000
28	GIQ0292	3,458	5617000	3,458	4562000
29	GIQ0254	2,843	5617000	2,843	4562000
30	GIQ0293	5,675	5617000	5,675	4562000
31	GIQ0294	6,092	5617000	6,092	4562000
32	GIQ0295	3,353	5617000	3,353	4562000
33	GIQ0296	1,157	5617000	1,157	4562000
34	GIQ0297	4,698	5617000	4,698	4562000
35	GIQ0277	11,440	5617000	11,440	4562000
36	GIQ0298	5,150	5617000	5,150	4562000
37	GIQ0299	933	5617000	933	4562000
38	GIQ0300	4,305	5617000	4,305	4562000
39	GIQ0302	687	5617000	687	4562000
40	GIQ0303	778	5617000	778	4562000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	GIQ0304	546	5617000	546	4562000
23	GIQ0305	573	5617000	573	4562000
24	GIQ0306	513	5617000	513	4562000
25	GIQ0307	631	5617000	631	4562000
26	GIQ0308	631	5617000	631	4562000
27	GIQ0309	180	5617000	180	4562000
28	Customer Studies Accruals	17,484	5617000		4562000
29	GIQ0203	3,383	5617000		
30	GIQ0184	3,191	5617000		
31	GIQ0185	121	5617000		
32	GIQ0186	454	5617000		
33	GIQ237A	16,724	5617000		
34	GIQ0265	713	5617000		
35	GIQ0270	9,202	5617000		
36	GIQ0271	10,628	5617000		
37	GIQ0284	7,958	5617000		
38	GIQ0270	1,290	5617000		
39	GIQ0271	979	5617000		
40	GIQ0223	1,738	1070000		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	GIQ0233	149	1070000		
23	GIQ0185	60	1070000		
24	GIQ237A-C	1,238	1070000		
25	GIQ0224	7,719	1070000		
26	GIQ0233	3,891	1070000		
27	GIQ0267	102,826	1070000		
28	GIQ0272	6,765	1070000		
29	GIQ0301	1,512	1070000		
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FOOTNOTE DATA

Schedule Page: 231 Line No.: 2 Column: a

Aref 551493, 551500, 551501, 551503

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	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	California DSM Regulatory Asset	(1,001,355)	816,551	908	1,914,337	-2,099,141
2	Idaho DSM Regulatory Asset	3,691,734	6,478,590	908	6,098,288	4,072,036
3	Utah DSM Regulatory Asset	7,622,161	57,253,987	908	36,355,470	28,520,678
4	Washington DSM Regulatory Asset	(64,615)	6,666,181	431,908	4,874,427	1,727,139
5	Wyoming DSM Regulatory Asset	310,066	1,343,594	908	4,122,625	-2,468,965
6	DSM Regulatory Assets- Accruals	5,464,896		232	487,179	4,977,717
7	Calif. Alternative Rate For Energy (CARE)	2,640,174		142	1,243,605	1,396,569
8	Transition Plan - OR (10)	6,161,872		930.2	3,892,299	2,269,573
9	2006 Transition Plan - WA (3)	955,571		920	637,047	318,524
10	2006 Transition Plan - ID (3)	1,220,389		920	610,194	610,195
11	2006 Transition Severance Costs - WY (3)	2,655,556		920	1,593,334	1,062,222
12	Deferred Income Taxes Electric	439,741,785		282	17,572,495	422,169,290
13	Implementation Costs OR Retail Access (5)	2		407.3	2	
14	Sch 781 Direct Access Shopping Incentive	(845)	231,712	407.3	299,227	-68,360
15	Glenrock Mine Excluding Reclamation UT (9)	1,126,424		930.2	1,014,206	112,218
16	Deferred Excess Net Power Costs - OR UE116	161,631	13,732			175,363
17	Deferred Excess Net Power Costs/ECAC - CA	(475,407)	1,256		2,130,220	-2,604,371
18	Deferred Excess Net Power Costs - WY 2007 (1)	8,635,355	28,900	555	8,664,255	
19	Deferred Excess Net Power Costs - WY 2008 (1)	24,231,911	2,807,845	555	17,068,920	9,970,836
20	Deferred Excess Net Power Costs - WY 2009		1,539,406			1,539,406
21	Deferred Excess Net Power Costs - WA Hydro (3)	6,017,444	417,102	555	2,070,140	4,364,406
22	Deferred Excess Net Power Costs - ID 2009		2,615,813			2,615,813
23	Environmental Costs (10)	7,034,873	1,801,923	925	1,320,414	7,516,382
24	Environmental Costs - WA (10)	(548,100)	88,747	925	132,490	-591,843
25	Reg Asset - Environmental Costs	4,477,314		253	1,036,173	3,441,141
26	Cholla Plant Transaction Costs (26)	9,634,148		557	1,122,425	8,511,723
27	Cholla Plant Transaction Costs - OR (26)	(461,896)	53,814			-408,082
28	Cholla Plant Transaction Costs - WA (26)	(832,637)	97,006			-735,631
29	Cholla Plant Transaction Costs - ID (26)	(283,021)	32,973			-250,048
30	Washington Colstrip #3 (22)	630,635		456	52,188	578,447
31	Derivative Net Regulatory Asset	442,142,129		426.5	74,840,538	367,301,591
32	Asset Retirement Obligations Regulatory Difference	57,282,618	19,971,276	230	12,262,322	64,991,572
33	Pension/Other Postretirement/SERP	563,859,328	39,122,490		27,236,402	575,745,416
34	RTO Grid West N/R Reg Asset	53,172		182.3	53,172	
35	Contra Reg Asset - RTO Grid West	(53,172)	53,172			
36	RTO Grid West N/R - OR	953,339	80,769			1,034,108
37	RTO Grid West N/R - WY (3)	230,055		904	138,033	92,022
38	RTO Grid West N/R - ID (5)	81,486		904	27,162	54,324
39	Deferred Independent Evaluator Fee - UT	(93,250)	133,677	235	53,000	-12,573
40	Deferred Independent Evaluator Fee - OR (1)	1,236,615	676,029	557	870,524	1,042,120
41	Deferred Intervenor Funding Grants - ID	35,160	39,403	928	13,185	61,378
42	Deferred Intervenor Funding Grants - OR	(266,896)	416,331	928, 431	324,467	-175,032
43	Deferred Intervenor Funding Grants - CA (1)	180,429		928	180,429	
44	TOTAL	1,626,353,730	190,913,030		266,353,108	1,550,913,652

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	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	BPA Washington Balancing Account	1,317,668	214,916	440,444	1,532,584	
2	BPA Idaho Balancing Account	1,926,018	155,562			2,081,580
3	OR Renewable Adjustment Clause (1)	12,962,257	3,935,282	142	11,700,598	5,196,941
4	Goodnoe Hills Damages		510,000			510,000
5	Lake Side Damages (38)	1,051,000		930.2	18,278	1,032,722
6	SB 408 Regulatory Asset - OR (1)	12,782,760	19,778,310	142	22,790,454	9,770,616
7	SB 408 Regulatory Asset - MCBIT	(22,043)				-22,043
8	Chehalis Plant Revenue Requirement - WA		18,000,000			18,000,000
9	Regulatory Assets - Reclassifications	1,948,992	5,536,681			7,485,673
10						
11						
12						
13						
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43						
44	TOTAL	1,626,353,730	190,913,030		266,353,108	1,550,913,652

Schedule Page: 232 Line No.: 17 Column: d

Account 440
Account 442
Account 555

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

Pensions and benefits are charged to functional accounts, which is consistent with where labor is charged.

Schedule Page: 232.1 Line No.: 9 Column: f

0The following summarizes regulatory assets reclassifications:

	Year Ended December 31, 2009	
Reclassified from Regulatory Assets to Regulatory Liabilities:		
California DSM Regulatory Asset	$	2,099,141
Wyoming DSM Regulatory Asset		2,468,965
Sch 781 Direct Access Shopping Incentive		68,360
Deferred Excess Net Power Costs/ECAC - CA		2,604,371
Deferred Intervenor Funding Grants - OR		175,032
Deferred Independent Evaluator Fee - UT		12,573
SB 408 Regulatory Asset - MCBIT		22,043
Reclassified from Regulatory Liabilities to Regulatory Assets:		
Washington Low Income Program		35,188
	$	7,485,673

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Joseph Settlement (20)	1,247,876		557	137,381	1,110,495
2						
3	Lacomb Irrigation (24)	598,170		557	45,720	552,450
4						
5	Bogus Creek (42)	1,283,120		557	41,280	1,241,840
6						
7	Mead Phoenix Availability					
8	& Trans Charge (50)	14,512,280		565	377,760	14,134,520
9						
10	TGS Buyout (23)	171,498		557	15,473	156,025
11						
12	Hermiston Swap (40)	4,735,871		557	171,693	4,564,178
13						
14	Deferred Longwall Costs	1,178,385	3,653,257	151	3,837,514	994,128
15						
16	Point to Point Transmission	1,155,763	2,607,625	142	1,189,488	2,573,900
17						
18	Deferred Coal Costs - Wyodak					
19	Settlement (22)	4,692,545		151	335,182	4,357,363
20						
21	Deferred Coal Costs - Arch					
22	Settlement (3)	4,300,468		151	2,587,363	1,713,105
23						
24	Deferred Colstrip Plant Costs	118,061	967,100			1,085,161
25						
26	Jim Boyd Hydro Buyout (11)	421,205		557	82,860	338,345
27						
28	Credit Agmt Costs (5)	1,921,498	38,500	431	452,226	1,507,772
29						
30	PCRB LOC/SBBPA Costs (5)	676,054		427	202,816	473,238
31						
32	PCRB Mode Conversion Costs (10)	390,004		427	128,039	261,965
33						
34	'94 Series Restruct. Costs (16)	746,024	469,040	427	109,652	1,105,412
35						
36	Emission Reduction Credits	406,980	2,550,000			2,956,980
37						
38	LGIA LT Transmission Prepaid	9,542,974	412,161	142, 232	6,726,832	3,228,303
39						
40	Lease Incentives (11)	1,425,467		454	155,119	1,270,348
41						
42	LT Lease Comm Prepaid (10)	832,801		931	92,820	739,981
43						
44	BPA LT Transm Prepaid	9,888,000	941,367	165, 232	1,236,058	9,593,309
45						
46	Lake Side Maint. Prepayment	6,077,531	4,772,844	107	1,372,787	9,477,588
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	72,806,094				67,302,539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Chehalis Maint. Prepayment	6,274,592	4,040,952	107	7,728,473	2,587,071
3						
4	Currant Creek Maint. Prepayment		1,167,388			1,167,388
5						
6	Other Deferred Debits with					
7	balances less than $100,000	208,927		various	97,253	111,674
8						
9						
10						
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14						
15						
16						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	72,806,094				67,302,539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Employee Benefits	246,078,312	243,734,412
3	Derivative Contracts	168,654,420	139,689,181
4	Regulatory Liabilities	41,530,110	40,091,582
5			
6			
7	Other	130,677,283	164,002,583
8	TOTAL Electric (Enter Total of lines 2 thru 7)	586,940,125	587,517,758
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)	586,940,125	587,517,758

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	04/14/2010	End of 2009/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				
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	No Par Serial Preferred	16,000,000		
22				
23	TOTAL PREFERRED STOCK	19,626,533		
24				
25				
26				
27				
28				
29				
30				
31				
32	Authorized and unissued Capital Stock			
33				
34				
35				
36				
37				
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39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
						22
414,633	41,463,300					23
						24
						25
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						41
						42

FOOTNOTE DATA

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

This class of stock is not redeemable.

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.: 32 Column: a

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

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, 2009, 30,000,000 shares authorized; 30,000,000 available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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 benefit from stock option exercises	14,422,979
5	Benefit plan separation	-3,575,760
6	Capital contributions	989,950,000
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		
12		
13		
14		
15		
16		
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40	TOTAL	1,002,063,956

FOOTNOTE DATA

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

Represents the fair value of stock options granted by Scottish Power plc 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

Represents the income tax deduction attributable to the exercise of stock options granted by Scottish Power plc.

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

Represents the effect of transferring benefit plans to PPM Energy, Inc. as a result of the sale of PacifiCorp by Scottish Power plc.

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

Represents capital contributions to PacifiCorp (with no shares of stock issued) from its indirect parent MidAmerican Energy Holdings Company ("MEHC"), of which $125,000,000 were made during the year ended December 31, 2009.

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

Represents a realized gain on stock related to separation of PPM Energy, Inc. participants from the deferred compensation plan.

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

Represents amounts associated with IRC 199 qualified production activities.

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

Represents contribution of Intermountain Geothermal Company to PacifiCorp from MEHC in March 2006, subsequent to the sale of PacifiCorp to MEHC. Intermountain Geothermal Company was merged with and into its direct parent, PacifiCorp, on August 31, 2007, with PacifiCorp surviving.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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		
10		
11		
12		
13		
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16		
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19		
20		
21		
22	TOTAL	41,288,207

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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			
4	8.271% Series due October 1, 2010	48,972,000	
5	7.978% Series due October 1, 2011	4,422,000	
6	6.900% Series due November 15, 2011	500,000,000	3,567,009
7			1,735,000 D
8	8.493% Series due October 1, 2012	19,772,000	
9	8.797% Series due October 1, 2013	16,203,000	
10	5.450% Series due September 15, 2013	200,000,000	1,422,659
11			232,000 D
12	4.950% Series due August 15, 2014	200,000,000	1,442,365
13			728,000 D
14	8.734% Series due October 1, 2014	28,218,000	
15	8.294% Series due October 1, 2015	46,946,000	
16	8.635% Series due October 1, 2016	18,750,000	
17	8.470% Series due October 1, 2017	19,609,000	
18	5.650% Series due July 15, 2018	500,000,000	3,067,221
19			905,000 D
20	5.500% Series due January 15, 2019	350,000,000	2,509,869
21			2,292,500 D
22	7.700% Series due November 15, 2031	300,000,000	2,874,150
23			864,000 D
24	5.900% Series due August 15, 2034	200,000,000	1,892,365
25			722,000 D
26	5.25% Series due June 15, 2035	300,000,000	2,912,055
27			1,080,000 D
28	6.10% Series due August 1, 2036	350,000,000	2,908,542
29			1,141,000 D
30	5.75% Series due April 1, 2037	600,000,000	589,216
31			24,000 D
32			
33	TOTAL	6,632,262,000	76,586,665

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
04/15/1992	10/01/2010	04/15/1992	10/01/2010	4,754,000	665,588	4
04/15/1992	10/01/2011	04/15/1992	10/01/2011	793,000	84,268	5
11/15/2001	11/15/2011	11/15/2001	11/15/2011	500,000,000	34,500,000	6
						7
04/15/1992	10/01/2012	04/15/1992	10/01/2012	5,178,000	532,893	8
04/15/1992	10/01/2013	04/15/1992	10/01/2013	5,440,000	550,802	9
09/15/2003	09/15/2013	11/15/2001	09/15/2013	200,000,000	10,900,000	10
						11
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	12
						13
04/15/1992	10/01/2014	04/15/1992	10/01/2014	11,179,000	1,089,435	14
04/15/1992	10/01/2015	04/15/1992	10/01/2015	20,721,000	1,879,524	15
04/15/1992	10/01/2016	04/15/1992	10/01/2016	9,346,000	868,163	16
04/15/1992	10/01/2017	04/15/1992	10/01/2017	10,562,000	951,647	17
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,171,528	18
						19
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	18,822,222	20
						21
11/15/2001	11/15/2031	11/15/2001	11/15/2031	300,000,000	23,100,000	22
						23
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	24
						25
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	26
						27
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	28
						29
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	30
						31
						32
				6,372,343,000	369,236,117	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	04/14/2010	End of 2009/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.25% Series due October 15, 2037	600,000,000	5,127,281
2			750,000 D
3	6.35% Series due July 15, 2038	300,000,000	2,290,333
4			1,671,000 D
5	6.00% Series due January 15, 2039	650,000,000	6,123,685
6			6,175,000 D
7	7.00% Series H Medium-Term Notes due Jul. 15, 2009	125,000,000	1,976,904
8			451,250 D
9	9.15% Series C Medium-Term Notes due Aug. 9, 2011	8,000,000	75,327
10	8.95% Series C Medium-Term Notes due Sept. 1, 2011	25,000,000	175,398
11	8.95% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	132,118
12	8.92% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	188,318
13	8.29% Series C Medium-Term Notes due Dec. 30, 2011	3,000,000	23,040
14	8.26% Series C Medium-Term Notes due Jan. 10, 2012	1,000,000	7,649
15	8.28% Series C Medium-Term Notes due Jan. 10, 2012	2,000,000	13,297
16	8.25% Series C Medium-Term Notes due Feb. 1, 2012	3,000,000	22,946
17	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
18	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
19	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
20	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
21	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
22	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
23	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
24	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
25	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
26	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
27	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
28	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
29	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
30	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
31			-81,560 P
32	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
33	TOTAL	6,632,262,000	76,586,665

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,395,833	1
						2
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	18,997,084	3
						4
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	38,133,333	5
						6
07/15/1997	07/15/2009	07/15/1997	07/15/2009		4,715,278	7
						8
08/09/1991	08/09/2011	08/09/1991	08/09/2011	8,000,000	732,000	9
08/16/1991	09/01/2011	08/16/1991	09/01/2011	25,000,000	2,237,500	10
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,790,000	11
08/16/1991	09/01/2011	08/16/1991	09/01/2011	20,000,000	1,784,000	12
12/31/1991	12/30/2011	12/31/1991	12/30/2011	3,000,000	248,700	13
01/09/1992	01/10/2012	01/09/1992	01/10/2012	1,000,000	82,600	14
01/10/1992	01/10/2012	01/10/1992	01/10/2012	2,000,000	165,600	15
01/15/1992	02/01/2012	01/15/1992	02/01/2012	3,000,000	247,500	16
01/20/1993	01/22/2013	01/20/1993	01/22/2013	10,000,000	813,000	17
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	18
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	19
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	20
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	21
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	22
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	23
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	24
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	25
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	26
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	27
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	28
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	29
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	30
						31
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	32
				6,372,343,000	369,236,117	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	04/14/2010	End of 2009/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	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
2	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
3	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
4	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
5	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
6	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
7	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
8	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
9	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
10	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
11	Subtotal - First Mortgage Bonds	5,893,892,000	61,731,625
12			
13	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
14			
15	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
16	5-5/8% Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1993	8,300,000	228,980
17			197,125 D
18	5.65% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993A	46,500,000	1,624,793
19	5-5/8% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993B	16,400,000	625,551
20			389,500 D
21	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
22	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
23	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
24	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
25	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
26	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
27	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
28			105,000 D
29	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
30	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
31	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
32	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
33	TOTAL	6,632,262,000	76,586,665

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.
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	1
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	2
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	3
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	4
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	5
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	6
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	7
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	8
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	9
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	10
				5,633,973,000	354,325,548	11
						12
						13
						14
11/17/1994	05/01/2013	11/17/1994	05/01/2013	40,655,000	366,868	15
11/15/1993	11/01/2021	11/15/1993	11/01/2021	8,300,000	476,835	16
						17
11/15/1993	11/01/2023	11/15/1993	11/01/2023	46,500,000	2,683,050	18
11/15/1993	11/01/2023	11/15/1993	11/01/2023	16,400,000	942,180	19
						20
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	185,191	21
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	65,159	22
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	1,146,055	23
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	77,291	24
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	132,958	25
01/01/1988	01/01/2014	01/01/1988	01/01/2014	17,000,000	680,352	26
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	600,357	27
						28
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	1,640,685	29
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	359,450	30
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	224,251	31
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	953,231	32
				6,372,343,000	369,236,117	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	04/14/2010	End of 2009/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	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	400,470,000	10,560,809
2			
3			
4	Pollution Control Obligations - Unsecured		
5			
6	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
7	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
8	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
9	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
10	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A	70,000,000	660,750
11	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
12	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A	50,000,000	422,443
13	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
14	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
15	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
16	6.150% Environ. Imprvmnt Rev Bonds, Emery County, UT, Series 1996	12,675,000	556,549
17			178,464 D
18			
19	Subtotal - Pollution Control Obligations - Unsecured	337,900,000	4,294,231
20			
21			
22			
23	TOTAL ACCOUNT 221	6,632,262,000	76,586,665
24			
25			
26	Reacquired Bonds: (Account 222)		
27			
28			
29	Advances from Associated Companies: (Account 223)		
30			
31			
32			
33	TOTAL	6,632,262,000	76,586,665

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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.
				400,470,000	10,533,913	1
						2
						3
						4
						5
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	206,385	6
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	139,396	7
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	497,116	8
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	100,793	9
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	625,694	10
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	437,777	11
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	533,479	12
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	415,921	13
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	386,588	14
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	253,994	15
09/24/1996	09/01/2030	09/24/1996	09/01/2030	12,675,000	779,513	16
						17
						18
				337,900,000	4,376,656	19
						20
						21
						22
				6,372,343,000	369,236,117	23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				6,372,343,000	369,236,117	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	04/14/2010	End of 2009/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	Other Long-Term Debt: (Account 224)		
2			
3	TOTAL ACCOUNT 224		
4			
5			
6	Long-Term Debt Authorized but Unissued		
7			
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12			
13			
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31			
32			
33	TOTAL	6,632,262,000	76,586,665

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
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						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				6,372,343,000	369,236,117	33

FOOTNOTE DATA

Schedule Page: 256 Line No.: 20 Column: a

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.

Idaho Public Utility Commission, Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

Schedule Page: 256.1 Line No.: 5 Column: a

In January 2009, PacifiCorp issued $650 million of its 6.00% First Mortgage Bonds due January 15, 2039. State commission authorizations for this issuance were as follows:

Oregon Public Utility Commission, Docket No. UF-4243, Order No. 08-013, dated January 14, 2008.

Idaho Public Utility Commission, Case No. PAC-E-07-16, Order No. 30489, dated January 22, 2008.

Schedule Page: 256.4 Line No.: 6 Column: a

For authorization for the issuance of long-term debt ($2.0 billion authorized; $200 million available as of December 31, 2009), refer to page 108, *Important Changes During the Year*, Item 6, of this Form No. 1.

Authorization to borrow the proceeds of pollution control revenue refunding bonds issued (total of $300,345,000 authorized and available as of December 31, 2009) by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado; and

Authorization to borrow the proceeds of new pollution control revenue bonds issued (total of $150,000,000 authorized and available as of December 31, 2009) by one or more of the following counties or municipalities: Emery, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; City of Gillette, Wyoming; Navajo County, Arizona; and Routt County, Colorado is as follows:

Oregon Public Utility Commission, Docket No. UF-4250, Order No. 08-382, dated July 29, 2008.

Idaho Public Utilities Commission, Case No. PAC-E-08-05, Order No. 30606, dated August 4, 2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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)	541,846,446
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	172,350,048
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,047,125,829
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	239,750,453
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	2,085,657,228
26	State Tax Deductions	-3,059,956
27	Federal Tax Net Income	-567,145,314
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	-198,500,860
31	Provision to Return Adjustment	-222,559,895
32	Tax Reserve changes	11,260,190
33	Tax Settlement	7,125,204
34	Contingency Reserve	1,500,000
35	Wind Credits	-44,324,047
36	Mining Rescue Training Credit	-66,989
37	Research & Experimentation Credits	-115,125
38	Foreign Tax Credit	-20,000
39	Fuel Tax Credit	-15,376
40	Current Fed Tax Interest	2,566,012
41		
42		
43	Federal Income Tax Accrual	-443,150,886
44		

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

Particular (Details)		Amounts
PMI Dividend Gross Up for Foreign Tax Credit	$	20,000
Income Tax Interest		2,666,318
Sec. 481a Adjustment - Repair Deduction		16,316,468
CIAC		53,575,515
Reimbursements		5,135,323
Avoided Costs		80,524,655
Capitalization of Test Energy		187,102
Energy trading derivatives - current		1,258,283
Energy trading derivatives - noncurrent		949,904
Regulatory liability BPA balancing accounts		1,430,552
WA Rate Refunds		228,659
Regulatory Liability - UT Home Energy Lifeline		13,830
Regulatory Liability - OR Balance Consol		2,619,115
OR Regulatory Asset/Liability Consolidation		13,819
Regulatory Liability - OR Energy Conservation Charge		46,722
Regulatory Liability - Blue Sky Program OR		96,929
Regulatory Liability - Blue Sky Program CA		19,763
UT DSM - SMUD Offset		2,850,000
Willow Wind Account Receivable		105,214
Deferred Coal Cost - Arch		2,587,363
Debt to Equity Securities Unrealized Gain/Loss		3,516,254
Equity Earnings in Subsidiaries		(1,811,740)
Total	$	172,350,048

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

Particular (Details)		Amounts
Fed/State Tax Expense	$	232,667,189
% capitalized labor costs for Power tax input		1,831,632
Meals & Entertainment		1,101,248
Penalties		600,132
Lobbying expenses		1,685,174
Meals & Entertainment - Bridger Coal		8,508
MEHC Insurance Services - Premium		6,969,001
Mining Rescue Training Credit Addback - PacifiCorp		46,236
30% capitalized labor costs for Power tax input		20,578,968
Book Depreciation		535,808,937
Book Cost Depletion - Addback		2,639,462
May 2000 Transition Plan Costs - OR		3,892,299
Glenrock Excluding Reclamation - UT		1,014,206
Regulatory Asset - Pension Liability Adj.		9,883,000
Regulatory Asset - Post Ret. Liability		12,226,000
Environmental Clean-up Accrual		554,665
Environmental Costs - WA		43,743
Cholla Plant Transaction Costs - APS Amortization		938,633
WA Disallowed Colstrip #3 - Write-off		52,188
CA Deferred Intervenor Funding		180,429
Regulatory Asset - Lake Side Liquidation		18,278
RTO Grid West N/R - Allowance		53,172
RTO Grid West Notes Receivable - WY		138,033
RTO Grid West Notes Receivable - ID		27,162

Regulatory Asset - Pension MMT - UT	338,368
Regulatory Asset - Post - Ret MMT - OR	199,297
Regulatory Asset - Post - Ret MMT - WY	278,231
Regulatory Asset - Post - Ret MMT - UT	332,959
Regulatory Asset - Post - Ret MMT - ID	394,287
Regulatory Asset - Post - Ret MMT - CA	17,235
Regulatory Asset - Deferred OR Independent Evaluator Fees	194,495
Unrecovered Plant - Powerdale	4,070,159
Deferred Excess Net Power Costs - CA	2,128,963
Deferred Excess Net Power Costs - WY	8,635,355
Deferred Excess Net Power Costs - WY 08	14,261,075
Deferred Excess Net Power Costs - WA Hydro	1,653,038
ID MEHC 2006 Transition Costs	610,194
WY - 2006 Transition Severance Costs	1,593,333
OR - RCAC Sep-Dec 07 Deferred	7,765,316
OR SB 408 Recovery	3,012,143
Trojan Decommissioning Costs - Regulatory	1,572,028
781 Shopping Incentive	67,515
SB 1149 Costs	2
NW Power Act - WA	2,220,689
Regulatory asset - Net Derivatives	74,840,538
Coal Pile Inventory Adjustment	1,198,886
Prepaid Taxes - UT PUC	7,167
Prepaid Taxes - ID PUC	66,620
RTO Grid West Note Receivable - w/o - WA	46,941
TGS Buyout	15,474
Lakeview Buyout	3,606
Joseph Settlement	137,381
Hermiston Swap	171,693
Western Coal Carrier Postretirement Benefit Accrual	380,000
Post Merger Loss-Reacquisition Debt - Addback	2,785,112
ARO Regulatory Liabilities	892,146
Non-ARO Liability - Regulatory Liability	23,435,597
Reg Liability - Other - Balance Reclass	244,836
Reg Liability - Def NPC Balance Reclass	2,604,370
Reg Liability - SB 1149 Balance Reclass	68,360
Property Insurance (same as Injuries & Damages)	109,564
CA - California Alternative Rate for Energy Program (CARE)	1,243,605
March 2006 Transition Plan Costs - WA	637,047
Bonus Liability - Electric - Cash Basis (2.5 months)	38,386
Pension / Retirement Accrual - Cash Basis	63,920
ARO Liability	22,457,843
Distribution O&M Amortization of Write-off	688
Bear River Settlement Agreement	433,059
Rogue River - Habitat Enhancement Liability	24,290
Lewis River Settlement Agreement	185,233
Other Environmental Liabilities	1,236,615
N. Umpqua Settlement Agreement	1,263,905
Umpqua Settlement Agreement	525,756
Deferred Revenue - Citibank	79,595
Accrued Insurance Premium Tax	192,477
Reverse Accrued Final Reclamation	293,378
Post Employment Benefits Book Reserve	1,785,438

FOOTNOTE DATA

Bridger Coal Company ARO - Liability	6,706,137
Penalties - PMI	279,107
PMI Fuel Tax Cr	15,376
Mine Rescue Training Credit Addback - PMI	20,753
Book Depreciation - PMI	15,299,289
Vacation Accrual - PMI	67,354
Coal Mine Development - PMI	4,444,185
Bridger Coal Company Section 471 Adjustment - PMI	521,125
Total	$ 1,047,125,829

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

Particular (Details)	Amounts
MEHC Insurance Services - Receivable	$ (20,302,078)
Tax Exempt Interest - CA IOU	(904)
Medicare Subsidy	(6,063,000)
Bridger Coal Tax Exempt Interest Income	(21,532)
AFUDC	(94,462,842)
Basis Intangible Difference	(4,645,782)
Def Regulatory Asset - OR Def Net Power Costs	(13,732)
Deferred Intervener Funding Grants	(91,864)
Contra - RTO Grid West N/R Allowance	(53,172)
WA - Chehalis Plant Revenue Requirement	(18,000,000)
Derivatives - Current	(38,567,924)
Regulatory Liability - WA Low Energy Program	(10,607)
Oregon Gain on Sale	(957,698)
Regulatory Liability - Blue Sky Program WA	(46,537)
Regulatory Liability - Blue Sky Program UT	(186,880)
Regulatory Liability - Blue Sky Program ID	(21,877)
Regulatory Liability - Blue Sky Program WY	(24,937)
Regulatory Liability - Deferred Benefit Arch Settlement	(1,836,574)
Regulatory Liability - UT Gain on Sale of Asset	(1,019,355)
Regulatory Liability - ID Gain on Sale of Asset	(156,434)
Regulatory Liability - WY Gain on Sale of Asset	(352,888)
SMUD Revenue Imputation - UT regulatory liability	(5,606,807)
Derivatives - noncurrent	(37,754,802)
Def Regulatory Asset - Transmission Service Deposit	(1,637,750)
Def Regulatory Asset - Foote Creek Contract	(137,640)
Deferred Regulatory Expense	(26,217)
Tenant Lease Allow - PSU Call Center	(60,323)
Unearned Joint Use Pole Contact Revenue	(179,120)
Duke/Hermiston Contract Renegotiation	(754,839)
Redding Contract - Prepaid	(549,996)
Bridger Coal Company Gain/Loss on Assets Disposed	(1,847)
Debt to Equity Securities Mark to Market Accrual - Bridger - Reclass	(3,516,254)
Dividend Received Deduction - PMI	(373,123)
PMI - Fuel Cost Adjustment	(1,168,993)
Bridger Coal Company Reclamation Trust Earnings - PMI	(1,146,125)
Total	$ (239,750,453)

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

Particular (Details)	Amounts
Tax Percentage Depletion - Blundell Steam Field (Prior IGC)	$ (431,583)
PPL Pre - 1943 Preferred Stock Div - Deduction	(381,063)

Utah Deferred Comp / COLI	(5,066,251)
Repair Deduction	(123,958,317)
Tax Depreciation	(1,622,113,173)
Capitalized Depreciation	(4,989,970)
Gain / (Loss) on Prop. Disposition	(25,010,569)
Coal Mine Development	(433,210)
Coal Mine Extension	(1,641,996)
Removal Costs	(51,617,122)
Cholla SHL-NOPA (Lease Amortization)	(68,842)
ARO - reclass to ARO liabilities	(16,001,650)
ARO - reclass to regulatory assets/liability & ARO liability	(23,435,597)
Book Gain/Loss on Land Sales	(1,077,748)
Tax Percentage Depletion - Deduction	(7,886,500)
DTA 105.154 Section 383 capital loss carry forward	(43,795)
DTA 105.155 Section 382 NOL carry forward	(186,450)
Tax Depletion	(173,901)
ARO Regulatory Assets	(7,348,338)
Goodnoe Hills Liquidation Damages - WY	(510,000)
RTO Grid West Notes Receivable - OR	(80,769)
Contra Pension Regulatory Asset MMT & CTG - OR	(979,620)
Contra Pension Regulatory Asset MMT & CTG - WY	(1,367,611)
Contra Pension Regulatory Asset CTG - UT	(5,867,400)
Contra Pension Regulatory Asset MMT & CTG - CA	(84,718)
Contra Pension Regulatory Asset CTG - WA	(237,141)
Deferred Excess Net Power Costs - WY 08	(1,539,406)
Deferred UT Independent Evaluation Fee	(80,676)
Deferred Excess Net Power Costs - ID 09	(2,615,813)
Idaho Customer Balancing Account	(155,562)
Weatherization	(18,706,576)
Regulatory Asset balance reclass	(2,619,115)
Reg Asset - SB 1149 Balance Reclass	(68,360)
Reg Asset - Other - Balance Reclass	(244,836)
Reg Asset - Def NPC Balance Reclass	(2,604,370)
Trapper Mining Stock Basis	(1,529,077)
Prepaid Taxes - OR PUC	(51,760)
Other Prepaid	(1,877,954)
Prepaid Taxes - Property Taxes	(4,680,901)
WY Joint Water Board Reserve - Deduction	(300,000)
Wasach workers comp reserve	(255,901)
West Valley Lease Reduction - CA	(28,291)
West Valley Lease Reduction - ID	(437,852)
West Valley Lease Reduction - WY	(1,365,919)
A&G Credit - CA	(45,315)
A&G Credit - ID	(451,245)
A&G Credit - WY	(1,476,750)
Self Insured Health Benefit	(707,070)
Vacation Accrual - Cash Basis (2.5 months)	(532,490)
Deferred Compensation Accrual - Cash Basis	(169,928)
Severance Accrual - Cash Basis	(233,045)
Accrued CIC Severance	(839,908)
Pension Liability	(69,316,122)
Post-Retirement Liability	(13,468,497)
SERP Liability	(690,345)

M&S Inventory Write-Off	(1,250,181)
Bad Debts Allowance - Cash Basis	(1,168,170)
R & E - Sec.174 Deduction	(9,127,439)
Oregon LIC Bid Liability Reserve	(342,000)
Accrued Royalties	(5,051,429)
Misc. Non-Current Accrued Liability	(833,757)
Misc. Current and Accrued Liability	(1,845,876)
Amortization NOPAs 99-00 RAR	(58,446)
MCI FOG Wire Lease	(314)
Injuries and Damages Accrual - Cash Basis	(1,013,694)
Bridger Coal Company ARO - Regulatory Asset	(6,706,137)
Bridger Coal Company Underground Mine Cost Depletion	(134,860)
PMI Overriding Coal Royalty % Depletion - PacifiCorp	(14,662)
Depreciation (Tax Depreciation M-1) - PMI	(25,160,966)
Coal Mine Extension Costs - PP&E - PMI	(731,202)
Sec. 263A Inventory Change - PMI	(307,884)
PMI Development Cost Amortization	(3,507,875)
PMI Pre-Stripping Costs	(221,151)
Bridger Coal Company Extraction Taxes Payable - PMI	(94,767)
Total	$ (2,085,657,228)

Schedule Page: 261 Line No.: 43 Column: b

Berkshire Hathaway Inc. includes PacifiCorp in its United States federal income tax return. PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

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

Under MEHC:
PPW Holdings LLC Sub-Group:
PacifiCorp
PPW Holdings LLC

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

MEHC Sub-Group:
Alaska Gas Transmission Company, LLC
Allerton Capital, Ltd
American Pacific Finance Company
American Pacific Finance Company II
Arizona Home Services, L.L.C.
BG Energy Holding LLC
BG Energy LLC
BGE Holdings LLC
CalEnergy Generation Operating Company
CalEnergy Holdings, Inc

MEHC Sub-Group (continued):

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
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc
CBSHome Relocation Services, Inc
CE Administrative Services, Inc
CE Electric (NY), Inc
CE Electric, Inc
CE Exploration Company
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
CE/TA LLC
Champion Realty, Inc
Chancellor Title Services, Inc
Cimmred Leasing Company
Columbia Title of Florida, Inc
Constellation Energy Holdings LLC
Cordova Energy Company LLC
Cordova Funding Corporation
Dakota Dunes Development Company
DCCO, Inc
Edina Financial Services, Inc
Edina Realty Insurance, LLC
Edina Realty Referral Network, Inc
Edina Realty Relocation, Inc
Edina Realty Title, Inc
Edina Realty, Inc
Esslinger-Wooten-Maxwell, Inc
E-W-M Referral Services, 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 N.C., Inc.
HN Real Estate Group, LLC
HN Referral Corporation
HomeServices Financial Holdings, Inc
HomeServices Financial, LLC
HomeServices Financial-Iowa, LLC
HomeServices Insurance, Inc
HomeServices of Alabama, Inc.
HomeServices of America, Inc
HomeServices of California, Inc
HomeServices of Florida, Inc
HomeServices of Illinois d/b/a Koenig & Strey GM
HomeServices of Iowa, Inc
HomeServices of Kentucky Real Estate Academy, LLC
HomeServices of Kentucky, Inc
HomeServices of Nebraska, Inc
HomeServices of Nevada, Inc
HomeServices of the Carolinas, Inc
HomeServices Referral Network, LLC
HomeServices Relocation, LLC
HSR Equity Funding, Inc
Huff Commercial Group, LLC
Huff Realty Insurance, LLC
Huff-Drees Realty, Inc.
IMO Company, Inc
InsuranceSouth, LLC
InterCoast Capital Company
InterCoast Energy Company
Iowa Realty Company, Inc
Iowa Realty Insurance Agency, Inc
Iowa Title Company
IWG Co 8
J.S. White Associates, Inc
JBRC, Inc.
Jenny Pruitt & Associates
Jim Huff Realty, Inc.
JP & A, Inc
JRHBW Realty, Inc d/b/a RealtySouth
Kansas City Title, Inc
Kentucky Residential Referral Service, 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
M & M Ranch Acquisition Company, LLC
M & M Ranch Holding Company, LLC
MEC Construction Services Company
MEHC Alaska Holding 1, LLC
MEHC Alaska Holding 2, LLC
MEHC America Transco, LLC
MEHC Insurance Services Ltd.
MEHC Investment, Inc

FOOTNOTE DATA

MEHC Sub-Group (continued):

MEHC Merger Sub Inc
MEHC Texas Transco, LLC
MHC Investment Company
MHC, Inc
Mid-America Referral Network, Inc.
MidAmerican Commercial R.E. Services, Inc
MidAmerican Energy Company
MidAmerican Energy Holdings Company
MidAmerican Energy Machining Services LLC
MidAmerican Funding, LLC
MidAmerican Nuclear Energy Company, LLC
MidAmerican Nuclear Energy Holdings Co., LLC
MidAmerican Services Company
MidAmerican Transmission, LLC
Midland Escrow Services, Inc
Midwest Capital Group, Inc
Midwest Gas Company
MortgageSouth, LLC
MWR Capital, Inc
Nebraska Land Title & Abstract Company
NNGC Acquisition, 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, L.L.C.
Plaza Mortgage Services, L.L.C.
Preferred Carolinas Realty, Inc
Preferred Carolinas Title Agency, L.L.C.
Professional Referral 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, L.L.C.
Roberts Brothers, Inc
Roy H. Long Realty Company, Inc
Safe Harbor Holding Company, LLC
Salton Sea Minerals Corporation
San Diego PCRE, Inc
Semonin Realtors, Inc
Southwest Relocation, LLC
The Escrow Firm
The Referral Company
TitleSouth, LLC
Trinity Mortgage Partners, Inc
Two Rivers, Inc
United Settlement Services, L.C.
West Valley Holdings, LLC

With respect to members of the MEHC Sub-Group, MEHC requires all subsidiaries to pay 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:

21st Communities, Inc.
21st Mortgage Corporation
21st SPC, Inc.
AAS-Lunken, Inc.
Acme Brick Company
Acme Brick DFW, Inc.
Acme Brick Sales Company
Acme Building Brands, Inc.
Acme Investment Company
Acme Management Company
Acme Ochs Brick and Stone, Inc.
Acme Service Company, L.P.
Adalet/Scott Fetzer Company
AEG Processing Center No. 58, Inc.
AEG Processing Center No. 35, Inc.
Agile Mfg, Inc.
AJF Warehouse Distributors, Inc.
AL/TEX Homes, Inc.
Albecca Inc.
Alexander City Flying Services, Inc.
All Bilt Uniforms
Alpha Cargo Motor Express, Inc.
Ambucor Health Solutions, Inc.
American All Risk Insurance Services, Inc.
American Centennial Insurance Company
American Commercial Claims Administrators, Inc.
American Dairy Queen Corporation
American Employers Group, Inc.
American Tile Supply, Inc.
Anderson Hardwood Floors, Inc.(fka Shaw-Razor Floors, Inc)
Apeks Apparel, Inc.
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logisitics, Inc.

Berkshire Hathaway Inc. Sub-Group (continued):

Applied Premium Finance, Inc.
Applied Processing Center No. 60, Inc.
Applied Risk Services of New York, Inc.
Applied Risk Services, Inc.
Applied Underwriters, Inc.
Atlanta International Insurance Company
AU Captive Risk Assurance Co
AU Captive Risk Assurance Co., Inc.
AU Holding Company, Inc.
AUI Employer Group No. 42, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Berkshire Hathaway Credit Corp.
Berkshire Hathaway Finance Corporation
Berkshire Hathaway Inc. (Common Parent)
Berkshire Hathaway Life Insurance Co. of NE
Berksire Hathaway Assurance Company
BH Affordable Housing Inc
BH Columbia Inc.
BH Finance, Inc.
BH Shoe Holdings, Inc.
BHG Structured Settlements, Inc.
BHR Inc.
BHSF, Inc.
Blue Chip Stamps
BNJ NetJets, Inc.
Boat America Corporation
Boat U.S, Inc.
Boat U.S. Travel International, Ltd.
Boot Royalty Company
Borsheim Jewelry Company Inc.
BR Agency, Inc.
Bricker-Mincolla Uniforms
Brilliant National Services, Inc.
British Insurance Company of Cayman
Brooks Sports, Inc. & Subsidiary
Brookwood Insurance Company
Business Wire Canada Inc.
Business Wire, Inc.
C & R Insurance Services, Inc.
California Employer Group No. 27, Inc.
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld/Scott Fetzer Company
Carefree/Scott Fetzer Company
Cavalier Homes, Inc.
Central States Indemnity Co. of Omaha
Central States of Omaha Companies, Inc.
CG Service, Inc.
Chatwell, Inc
Chippewa Shoe Company
Citadel Insurance Company
CJE II, Inc.
Claims Services, Inc.
Clayton Commercial Buildings, Inc.
Clayton Homes, Inc.
CMH Capital, Inc.
CMH Hodgenville, Inc.
CMH Homes, Inc.
CMH Manufacturing West, Inc.
CMH Manufacturing, Inc.
CMH of KY, Inc.
CMH Parks, Inc.
CMH Services, Inc.
CMH Set and Finish, Inc.
Cologne Reinsurance Company of America
Cologne Services Corporation
Columbia Insurance Company
Combined Claims Services, Inc.
Command Uniforms
Commercial Casualty Insurance Company
Commercial General Indemnity, Inc.
Commonwealth Uniforms Inc.
Complementary Coatings Corporation
CompuTrus, Inc.
Continental Divide Insurance Co.
Continental Indemnity Company
Corbond Corporation
Cornhusker Casualty Company
CORT Business Services Corporation
Coverage Dynamics Group, Inc.
Criterion Insurance Agency
Cross Creek Apparel, LLC
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.
Cumberland Asset Management, Inc.
Cypress Insurance Company
Dairy Queen Corporate Stores, Inc.
Dairy Queen of Georgia, Inc.
Denver Brick Company
Dexter Shoe Company
DQ Funding Corporation
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
Eco Color Company

FOOTNOTE DATA

Berkshire Hathaway Inc. Sub-Group (continued):

Edmonds Material and Equipment Co.
Elm Street Corporation
Employers Insurance Services, Inc.
Eureka Brick and Tile Company
Executive Jet Europe, Inc.
Executive Jet Management, Inc.
Expertos, S.A. de C.V.
Fairfield Insurance Co.
Faraday Capital Limited
Farriors, Inc.
FFG Insurance Company
Finial Holdings, Inc.
Finial Insurance Company
Finial Reinsurance Company
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
Floors Inc.
Footwear Investment Company
Forest River Financial Services, Inc.
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 Trading Company
Fruit of the Loom, Inc.
FSI Delaware Holding Corp.
FTL Regional Sales Co., Inc.
FTL Sales Company, Inc.
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 Insurance Agency, Inc.
GEICO Products, Inc.
Gen Re Intermediaries Corporation
General Re Corporate Finance, Inc.
General Re Corporation
General Re Financial Products Corporation
General Re Funding Corporation
General Re Investment Holdings Corporation
General Re New England Asset Management
General Re Services Corporation
General Reinsurance Corporation
General Star Indemnity Company
General Star Management Company
General Star National Insurance Company
Genesis Indemnity Insurance Company
Genesis Insurance Company
Genesis Underwriting Management Company
Giles Industries, Inc.
Glass Mountain Optics, Inc.
GMK, Ltd.
Golden Skillet International, Inc.
Government Employees Financial Corporation
Government Employees Insurance Company
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
HeatPipe Technologies
Helzberg's Diamond Shops, Inc.
Henley Holdings, LLC
Hohmann & Barnard, Inc.
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Indecor Group Inc. d/b/a J.C.Licht Company
Innovative Building Products, Inc.
Insurance Counselors of Nevada, Inc.
International America Group Inc.
International American Management Company
International Dairy Queen, Inc.
International Insurance Underwriters,Inc.
Isabela Shoe Corporation
J. S. Justin, Inc.
Janovic/Plaza Inc.
JM E3 CO
Johns Manville China, LTD.
Johns Manville Corporation
Johns Manville, Inc.
Jordan's Furniture, Inc.
Justin Belt Company, Inc.
Justin Boot Company
Justin Brands, Inc.

FOOTNOTE DATA

Berkshire Hathaway Inc. Sub-Group (continued):

Justin Industries, Inc.
Kale Uniforms
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kay Uniforms
Kleberg Holdings Inc.
LA Terminals, Inc.
Leesburg Yarn Mills, Inc.
M & C Products, Inc.
Macro Retailing, Inc.
Mapletree Transportation, Inc.
Martin Manufacturing Company
Martin Mills, Inc.
Maryland Ventures, Inc.
McCain Uniform Company Inc.
McCarty-Hull Cigar 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.
MedPro Risk Retention Services, Inc.
Metro Uniforms
MH Transport, Inc.
Miller-Sage, Inc.
MiTek Framings, Inc.
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek, Inc.
MMX Corporation
Mobile Disaster Structures, Inc.
Mossy Oak Apparel Company
Mount Vernon Fire Insurance Company
Mountain View Marketing, Inc.
Mouser Electronics, 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 Reinsurance Corporation
Nationwide Uniforms
Nebraska Furniture Mart, Inc.
NetJets Aviation Inc.
NetJets Europe Holdings LLC
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.
NJE Holdings LLC
NJI Sales Inc.
NJI, Inc.
Nocona Boot Company
North American Casualty Co
North Star Reinsurance Corporation
North Star Syndicate, Inc.
Northern States Agency, Inc.
Northland/Scott Fetzer Company
Oak River Insurance Company
OBH Inc.
Old City Paint & Decorating, Inc.
Orange Julius of America
Pan-Am Shoe Co., Inc.
Pima Uniforms
Pinnacle Paint & Decorating, Inc.
PJR Management Inc
Plaza Financial Services Co.
Plaza Resources Co.
Ponce Fashions, Inc.
Portland Gold Corp. d/b/a/ Maine Paint Service
Precision Brand Products
Precision Steel Warehouse - Charlotte
Precision Steel Warehouse - Franklin Park
Priority One Financial Services, Inc.
Pro Installations, Inc.
Professional Datasolutions, Inc.
Promesa Health, Inc.
Queen Carpet Corporation
R.C.Willey Home Furnishings
Rabun Apparel, Inc.
Railsplitter Holdings Corporation
Rainbow State Paint & Decorating Inc.
Redwood Fire and Casualty Insurance Co.
RENTCO Trailer Corporation
Resolute Management Inc.

FOOTNOTE DATA

Berkshire Hathaway Inc. Sub-Group (continued):

Richline Group, Inc.
Ringwalt & Liesche Co
Roberts Men's Shop
Running with Heels (Micro Retailing, Inc.)
Russell Brands LLC (f/k/a Russell Corporation)
Russell Financial Services, Inc.
Salado Sales, Inc.
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
Seattle Paint Supply, Inc.
Seaworthy Insurance Company
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 Diversified Services, Inc.
Shaw Floors, Inc.
Shaw Funding Company
Shaw Industries Group, Inc.
Shaw Industries, Inc.
Shaw International Services, Inc. (fka Shaw Financial Services, Inc.)
Shaw Retail Properties, Inc.
Shaw Transport, Inc.
SHX Flooring, Inc.
SHX Leasing, Inc.
SidePlate Systems, Inc.
Silver State Uniforms
Simon's Incorporated
Simpad, Inc.
Soco West, Inc.
Sofft Shoe Company, Inc.
Sol Frank Uniforms Inc.
Somerset Services
Southern Energy Homes of Pennsylvania, Inc.
Southern Energy Homes, Inc.
Sportexe Construction Services, Inc.
Stahl/Scott Fetzer Company
Star Furniture Company
Strategic Staff Management, Inc.
Strick Mexicana, S.A.
Technical Coatings Co.
The Ben Bridge Corporation
The BVD Licensing Corp.
The Eagle Company
The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Medical Protective Company
The Pampered Chef North America, Ltd
The Pampered Chef, Ltd
The Scott Fetzer Company
TMI Custom Air Systems, Inc.
Tony Lama Company
Top Five Club, Inc.
TPC - European Holdings, Ltd.
Transco, Inc.
TTI, Inc.
U.S. Investment Corporation
U.S. Liability Insurance Company
U.S. Underwriters Insurance Company
Undergarment Fashions, Inc.
Unified Supply Chain, Inc.
Uniforms of Texas
Union Sales, Inc.
Union Underwear Co., Inc.
Unione Italiana Reinsurance Company of America, Inc.
United Consumer Financial Services, Inc.
United Direct Finance Inc.
United States Aviation Underwriters, Inc.
Universal Uniforms
Vanderbilt ABS Corp.
Vanderbilt Mortgage & Finance, Inc.
Vanderbilt Property & Casualty Insurance Co., Ltd.
Vanderbilt SPC, Inc.
Vanity Fair Inc.
Veritas Insurance Group, Inc.
Vessel Assist Association of America, Inc.
Vessel Assist Insurance Services, Inc.
VFI-Mexico, Inc.
Virginia Paint Co., 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.
Whittaker, Clark & Daniels, Inc
Witt Brick & Supply, Inc.
WMC Corp.
Woodperfect, Inc.
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 Finance Corporation

FOOTNOTE DATA

Berkshire Hathaway Inc. Sub-Group (continued):

XTRA Intermodal, Inc.
XTRA International Pacific, LTD.
XTRA International, LTD.
XTRA Mexicana, S.A. de C.V.
Zuckerbergs Uniforms

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income		39,022,654	-443,150,886	-260,820,650	7,394,247
3	FICA	452,938	17,521	37,052,655	36,833,710	
4	Unemployment	57,329		364,709	369,136	
5	Excise Tax - Coal	90,184		4,218,596	4,140,975	
6	Subtotal	600,451	39,040,175	-401,514,926	-219,476,829	7,394,247
7						
8	State:					
9						
10	Arizona:					
11	Property	917,815		1,921,133	1,878,382	
12	Income		638,661	440,661	-153,076	
13	Subtotal	917,815	638,661	2,361,794	1,725,306	
14						
15	California:					
16	Property			2,215,392	2,215,392	
17	Unemployment	1,497		31,560	33,057	
18	Franchise-Income		657,111	5,557	-287,199	
19	Use	7,251		140,752	142,422	
20	Local Franchise	862,975		1,159,804	1,086,413	
21	Subtotal	871,723	657,111	3,553,065	3,190,085	
22						
23	Colorado:					
24	Property	1,920,000		1,935,380	1,954,380	
25	Income		138,583	94,583		
26	Subtotal	1,920,000	138,583	2,029,963	1,954,380	
27						
28	Idaho:					
29	Property	1,747,058		3,496,756	3,187,061	
30	Income		-330,042	-590,251	83,230	
31	KWh	11,912		32,595	29,495	
32	Unemployment	842		44,434	44,543	
33	Use	3,361		110,331	112,855	
34	Subtotal	1,763,173	-330,042	3,093,865	3,457,184	
35						
36	Montana:					
37	Property	1,398,191		2,802,927	2,801,127	
38	Corporate License-Income		282,662	226,484	-209,838	
39	Unemployment	138		592	730	
40	Energy License	60,495		166,489	193,622	
41	TOTAL	28,648,482	51,215,626	-257,508,339	-77,402,933	9,256,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
(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)	No.
						1
15,057,106	243,804,243	-472,156,577			29,005,691	2
654,362					37,052,655	3
52,902					364,709	4
167,805					4,218,596	5
15,932,175	243,804,243	-472,156,577			70,641,651	6
						7
						8
						9
						10
960,566		1,921,133				11
	44,924	386,198			54,463	12
960,566	44,924	2,307,331			54,463	13
						14
						15
		2,016,663			198,729	16
					31,560	17
	364,355	-116,046			121,603	18
5,581					140,752	19
936,366		1,159,804				20
941,947	364,355	3,060,421			492,644	21
						22
						23
1,901,000		1,934,635			745	24
	44,000	94,579			4	25
1,901,000	44,000	2,029,214			749	26
						27
						28
2,056,753		3,312,653			184,103	29
	343,439	-860,429			270,178	30
15,012		32,595				31
733					44,434	32
837					110,331	33
2,073,335	343,439	2,484,819			609,046	34
						35
						36
1,399,991		2,802,927				37
	-153,660	197,105			29,379	38
					592	39
33,362		166,489				40
46,747,021	258,675,803	-350,305,291			92,796,952	41

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Wholesale Energy	43,104		118,652	137,968	
2	Subtotal	1,501,928	282,662	3,315,144	2,923,609	
3						
4	New Mexico:					
5	Property	5,306		8,247	13,553	
6	Income		1,752	1,802	50	
7	Subtotal	5,306	1,752	10,049	13,603	
8						
9	Oregon:					
10	Property		8,670,415	18,314,174	19,264,470	
11	Unemployment	57,574		1,613,738	1,632,793	
12	Wilsonville Payroll	198		850	760	
13	Excise-Income		-3,349,849	-3,151,426	1,121,010	
14	City of Portland-Income		-84,414	-85,314	100	
15	Department of Energy		324,718	682,162		
16	Tri-Met	347,378		891,484	887,403	
17	Lane County			2,571	2,571	
18	Franchise	4,064,890		21,551,799	21,421,018	
19	Subtotal	4,470,040	5,560,870	39,820,038	44,330,125	
20						
21	Utah:					
22	Property	881,853		43,374,988	43,858,491	
23	Income		5,225,854	1,211,934	-329,716	
24	Unemployment	53,173		205,927	206,950	
25	Navajo Nation			1,549	1,549	
26	Use	416,901		4,133,107	4,235,093	
27	Subtotal	1,351,927	5,225,854	48,927,505	47,972,367	
28						
29	Washington:					
30	Property	8,553,361		6,095,225	7,861,586	
31	Unemployment	8,883		67,087	73,359	
32	Business & Occupation	25,795		159,722	180,519	
33	Public Utility	875,000		10,921,843	10,121,843	
34	Natural Gas Use Tax	964,129		2,420,896	2,935,466	
35	Use	64,704		803,403	829,184	
36	Land Tax			63	63	
37	Subtotal	10,491,872		20,468,239	22,002,020	
38						
39	Wyoming:					
40	Property	4,351,898		13,087,488	10,894,988	
41	TOTAL	28,648,482	51,215,626	-257,508,339	-77,402,933	9,256,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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
(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)	No.
23,788		118,652				1
1,457,141	-153,660	3,285,173			29,971	2
						3
						4
		8,247				5
		1,528			274	6
		9,775			274	7
						8
						9
	9,620,711	17,771,107			543,067	10
38,519					1,613,738	11
288					850	12
	922,587	-4,826,485			1,675,059	13
	1,000	-86,081			767	14
357,444		682,162				15
351,459					891,484	16
					2,571	17
4,195,671		21,551,799				18
4,943,381	10,544,298	35,092,502			4,727,536	19
						20
						21
398,350		40,790,528			2,584,460	22
	3,684,204	-577,730			1,789,664	23
52,150					205,927	24
		1,549				25
314,915					4,133,107	26
765,415	3,684,204	40,214,347			8,713,158	27
						28
						29
6,787,000		5,951,027			144,198	30
2,611					67,087	31
4,998		156,529			3,193	32
1,675,000		10,921,843				33
449,559					2,420,896	34
38,923					803,403	35
		63				36
8,958,091		17,029,462			3,438,777	37
						38
						39
6,544,398		10,494,186			2,593,302	40
46,747,021	258,675,803	-350,305,291			92,796,952	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	04/14/2010	End of 2009/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.
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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 Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Unemployment	4,881		170,438	173,318	
2	Franchise	241,500		1,513,182	1,515,582	
3	Use	111,384		1,324,943	1,325,033	
4	Annual Report			53,226	53,226	
5	Subtotal	4,709,663		16,149,277	13,962,147	
6						
7	State Other			3,761,160		1,861,985
8						
9	Miscellaneous:					
10	Goshute Possessory	27,023		13,722	40,745	
11	Sho-Ban Possessory			132,712	132,712	
12	Navajo Possessory	17,561		36,004	35,563	
13	Ute Possessory			17,523	17,523	
14	Crow Possessory			62,262	62,262	
15	Umatilla Possessory			52,080	52,080	
16	Other Taxes			202,185	202,185	
17	Subtotal	44,584		4,277,648	543,070	1,861,985
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	28,648,482	51,215,626	-257,508,339	-77,402,933	9,256,232

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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.
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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
(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)	No.
2,001					170,438	1
239,100		1,513,182				2
111,294					1,324,943	3
		53,226				4
6,896,793		12,060,594			4,088,683	5
						6
1,899,175		3,761,160				7
						8
						9
		13,722				10
		132,712				11
18,002		36,004				12
		17,523				13
		62,262				14
		52,080				15
		202,185				16
1,917,177		4,277,648				17
						18
						19
						20
						21
						22
						23
						24
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						31
						32
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						34
						35
						36
						37
						38
						39
						40
46,747,021	258,675,803	-350,305,291			92,796,952	41

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

		Amount	Account
Reclass of unrecognized tax benefits	$	7,382,752	174
Reclass as a result of an effective settlement of an Internal Revenue Service Exam		11,548	283
Effective settlement of Internal Revenue Service Exam		(53)	131
Total adjustments	$	7,394,247	

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

Federal income tax applicable to other income & deductions - 409.2

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

Payroll taxes of $2,007,076 for Energy West were charged to Fuel Stock - 151. All other payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

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

Payroll taxes of $20,862 for Energy West were charged to Fuel Stock - 151. All other payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

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

Fuel inventory - 151

Schedule Page: 262 Line No.: 12 Column: l

State income tax applicable to other income & deductions - 409.2

Schedule Page: 262 Line No.: 16 Column: l

		Amount	Account
Taxes applicable to other income & deductions	$	141,647	408.2/409.2
Construction		55,601	107
Distribution rent expense, rents		1,481	589
Total	$	198,729	

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

Various operations and maintenance accounts.

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

State income tax applicable to other income & deductions - 409.2

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

Clearing account - 184

Schedule Page: 262 Line No.: 24 Column: l

Taxes applicable to other income & deductions - 408.2, 409.2

Schedule Page: 262 Line No.: 25 Column: l

State income tax applicable to other income & deductions - 409.2

Schedule Page: 262 Line No.: 29 Column: l

		Amount	Account
Taxes applicable to other income & deductions	$	1,945	408.2/409.2
Construction		182,158	107
Total	$	184,103	

Schedule Page: 262 Line No.: 30 Column: l

State income tax applicable to other income & deductions - 409.2

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

Various operations and maintenance accounts.

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

Clearing account - 184

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

State income tax applicable to other income & deductions - 409.2

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

Various operations and maintenance accounts.

Schedule Page: 262.1 Line No.: 6 Column: l

State income tax applicable to other income & deductions - 409.2

Schedule Page: 262.1 Line No.: 10 Column: l

	Amount	Account
Taxes applicable to other income & deductions	$ 19,588	408.2/409.2
Construction	467,605	107
Distribution rent expense, rents	55,874	589
Total	$ 543,067	

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

Various operations and maintenance accounts.

Schedule Page: 262.1 Line No.: 12 Column: l

Various operations and maintenance accounts.

Schedule Page: 262.1 Line No.: 13 Column: l

State income tax applicable to other income & deductions - 409.2

Schedule Page: 262.1 Line No.: 14 Column: l

State income tax applicable to other income & deductions - 409.2

Schedule Page: 262.1 Line No.: 16 Column: l

Various operations and maintenance accounts.

Schedule Page: 262.1 Line No.: 17 Column: l

Various operations and maintenance accounts.

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

	Amount	Account
Taxes applicable to other income & deductions	$ 86,194	408.2/409.2
Fuel stock	1,639,605	151
Construction	858,661	107
Total	$ 2,584,460	

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

State income tax applicable to other income & deductions - 409.2

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

	Amount	Account
Fuel stock	$ 20,308	151
Operations and maintenance accounts	185,619	Various
Total	$ 205,927	

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

Clearing account - 184

Schedule Page: 262.1 Line No.: 30 Column: l

	Amount	Account
Taxes applicable to other income & deductions	$ 91,999	408.2/409.2
Construction	42,288	107
Distribution rent expense, rents	9,911	589
Total	$ 144,198	

Schedule Page: 262.1 Line No.: 31 Column: l

Various operations and maintenance accounts.

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

Fuel stock - 151

Schedule Page: 262.1 Line No.: 34 Column: l

Fuel stock - 151

Schedule Page: 262.1 Line No.: 35 Column: l

Clearing account - 184

Schedule Page: 262.1 Line No.: 40 Column: l

	Amount	Account
Taxes applicable to other income & deductions	$ 934	408.2/409.2
Construction	2,579,537	107
Distribution rent expense, rents	12,831	589
Total	$ 2,593,302	

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

Various operations and maintenance accounts.

Schedule Page: 262.2 Line No.: 3 Column: l

Clearing account - 184

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

	Amount	Account
Reclass as a result of an effective settlement of an Internal Revenue Service Exam	$ 1,471,654	174
Effective settlement of Internal Revenue Service Exam	390,331	131
Total adjustments	$ 1,861,985	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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%	38,809,669			411.4	1,808,768	
6	10%	8,918,674			420	1,624,452	
7	Idaho	777,893			411.4	65,436	
8	TOTAL	48,506,236				3,498,656	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	10%	1,322,120			420	440,808	
14							
15	Total Nonutility	1,322,120				440,808	
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	04/14/2010	End of 2009/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
37,000,901	48.37		5
7,294,222	30		6
712,457	30		7
45,007,580			8
			9
			10
			11
			12
881,312	30		13
			14
881,312			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			46
			47
			48

FOOTNOTE DATA

Schedule Page: 266 Line No.: 5 Column: e

46(f)2

Schedule Page: 266 Line No.: 6 Column: e

46(f)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	04/14/2010	End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1						
2	Working Capital Deposits	2,841,878			568,666	3,410,544
3						
4	Reclamation Costs - Trapper Mine	4,276,612			222,740	4,499,352
5						
6	Reclamation Costs - Deseret Mine	534,826				534,826
7						
8	Reclamation Costs - Trail					
9	Mountain Mine	1,126,798	131	35,850		1,090,948
10						
11	Deferred Compensation Plans	9,961,369	124	2,002,763	1,832,835	9,791,441
12						
13	Transmission Service Deposits	3,531,125	131, 235	4,793,723	3,155,973	1,893,375
14						
15	MCI F.O.G. wire lease	558,097	454	3,347,013	3,346,699	557,783
16						
17	Redding Contract (20)	3,850,072	456	549,996		3,300,076
18						
19	Foote Creek Contract (15)	842,942	142	137,640		705,302
20						
21	Environmental Liabilities	5,691,680	131, 182.3	922,008	2,158,623	6,928,295
22						
23	Unearned Joint Use Pole Contact	3,521,617	454	8,425,899	8,246,779	3,342,497
24						
25	Oregon DSM Loans NPV Unearned	716,516	456	255,974		460,542
26						
27	Other Deferred Credits - C&T	833,757	555	833,757		
28						
29	Deferred Revenue -					
30	Duke/Hermiston Gas Settlement (5)	1,918,549	547, 555	754,839		1,163,710
31						
32	Transmission Security Deposits	1,300,000			250,000	1,550,000
33						
34	Other deferred credits with					
35	balances less than $500,000	1,256,184	various	327,395		928,789
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	42,762,022		22,386,857	19,782,315	40,157,480

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	1,654,239,715	1,039,771,299	314,322,980
3	Gas			
4	FAS 109 Regulatory Asset	439,741,785		
5	TOTAL (Enter Total of lines 2 thru 4)	2,093,981,500	1,039,771,299	314,322,980
6	Nonutility	1,743,433		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	2,095,724,933	1,039,771,299	314,322,980
10	Classification of TOTAL			
11	Federal Income Tax	1,845,017,675	915,385,599	276,721,169
12	State Income Tax	250,707,258	124,385,700	37,601,811
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	04/14/2010	End of 2009/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		282	8,512,579	190,282,283	8,438,717	2,379,614,172	2
							3
		182	17,572,494			422,169,291	4
			26,085,073		8,438,717	2,801,783,463	5
10,848	882,565					871,716	6
							7
							8
10,848	882,565		26,085,073		8,438,717	2,802,655,179	9
							10
9,550	776,985		22,964,570		7,429,211	2,467,379,311	11
1,298	105,580		3,120,503		1,009,506	335,275,868	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	04/14/2010	End of 2009/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets	440,004,173	48,668,071	54,261,407
4				
5				
6	Other Deferred Liabilities	50,755,602	70,039,834	70,287,258
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	490,759,775	118,707,905	124,548,665
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)	490,759,775	118,707,905	124,548,665
20	Classification of TOTAL			
21	Federal Income Tax	432,050,152	104,507,123	109,649,165
22	State Income Tax	58,709,623	14,200,782	14,899,500
23	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	04/14/2010	End of 2009/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
44,915,501	73,318,233	182	1,353,721	190	11,607,692	416,262,076	3
							4
							5
	477,531	190, 282	50,703,642		35,310,385	34,637,390	6
							7
							8
44,915,501	73,795,764		52,057,363		46,918,077	450,899,466	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
44,915,501	73,795,764		52,057,363		46,918,077	450,899,466	19
							20
39,542,352	64,967,729		45,829,848		41,305,364	396,958,249	21
5,373,149	8,828,035		6,227,515		5,612,713	53,941,217	22
							23

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 276 Line No.: 6 Column: i

Accounts
190 Accumulated Deferred Income Taxes
282 Accum. Deferred Income Taxes-Other Property
219 Accumulated Other Comprehensive Income
236 Taxes Accrued

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Income Tax Regulatory Liability	21,373,276	190	1,013,954		20,359,322
2	Income Tax Reg. Liab. - WA Flow Through	9,793,585	190	8,916,956		876,629
3	OR Gain on Sales of Assets (1)	1,416,868	142	1,246,456	288,758	459,170
4	Property Insurance Reserve				109,564	109,564
5	SMUD Revenue Imputation (11)	25,669,853	440,442	5,944,105	337,298	20,063,046
6	SMUD Revenue Imputation UT				2,850,000	2,850,000
7	Oregon Rate Refund	79,964				79,964
8	WA Rate Refund				228,659	228,659
9	Utah Home Energy Lifeline	400,026	142	2,665,935	2,679,765	413,856
10	BPA Washington Balancing Account				903,021	903,021
11	BPA Oregon Balancing Account	988,540			1,430,552	2,419,092
12	ARO/ Reg Difference - Deer Creek Mine Reclamation	621,205	230	156,465	335,798	800,538
13	ARO/Reg Difference - Trojan Nuclear Plant	3,373,343	230	102,707	338,312	3,608,948
14	CA West Valley Lease Red (3)	28,291	142	29,510	1,219	
15	ID West Valley Lease Red (3)	437,852	440,442,142	437,852		
16	WY West Valley Lease Red. (3)	1,365,919	440,442,142	1,365,919		
17	A&G Credit - CA (3)	45,316	142	47,268	1,952	
18	A&G Credit ID (3)	451,245	440,442,142	451,245		
19	A&G Credit WY (3)	1,476,750	440,442,142	1,525,805	49,055	
20	Washington Low Income Program	(24,581)	142	1,157,998	1,147,391	-35,188
21	OR Consolidation	117,653			13,818	131,471
22	Blue Sky - OR	261,314	232	1,172,921	1,269,850	378,243
23	Blue Sky - WA	86,822	232	203,859	157,322	40,285
24	Blue Sky - CA	47,636	232	50,817	70,580	67,399
25	Blue Sky - UT	921,774	232	2,751,129	2,564,250	734,895
26	Blue Sky - ID	50,500	232	80,807	58,930	28,623
27	Blue Sky - WY	101,066	232	223,005	198,068	76,129
28	OR Energy Conservation Charge	775,874	232	8,579,678	8,626,400	822,596
29	CA Gain on Sale of Assets	45,034				45,034
30	UT Gain on Sale of Assets	1,019,355	421.1	1,019,355		
31	ID Gain on Sale of Assets	156,434	182.3	156,434		
32	WY Gain on Sale of Assets	352,888	421.1	352,888		
33	Deferred Arch Coal Settlement (3)	3,053,860	557	1,836,574		1,217,286
34	Reg Liability - Reclassifications	1,948,992			5,536,681	7,485,673
35						
36						
37						
38						
39						
40						
41	TOTAL	76,456,654		41,489,642	29,197,243	64,164,255

Schedule Page: 278 Line No.: 34 Column: f

The following summarizes regulatory liabilities reclassifications:

	Year Ended December 31, 2009
Reclassified from Regulatory Assets to Regulatory Liabilities:	
California DSM Regulatory Asset	$ 2,099,141
Wyoming DSM Regulatory Asset	2,468,965
Sch 781 Direct Access Shopping Incentive	68,360
Deferred Excess Net Power Costs/ECAC - CA	2,604,371
Deferred Intervenor Funding Grants - OR	175,032
Deferred Independent Evaluator Fee - UT	12,573
SB 408 Regulatory Asset - MCBIT	22,043
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Washington Low Income Program	35,188
	$ 7,485,673

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,346,519,773	1,345,013,663
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,120,956,943	1,062,312,561
5	Large (or Ind.) (See Instr. 4)	976,991,304	998,397,465
6	(444) Public Street and Highway Lighting	20,913,398	19,865,594
7	(445) Other Sales to Public Authorities	19,032,148	18,443,905
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,484,413,566	3,444,033,188
11	(447) Sales for Resale	643,321,157	860,950,758
12	TOTAL Sales of Electricity	4,127,734,723	4,304,983,946
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,127,734,723	4,304,983,946
15	Other Operating Revenues		
16	(450) Forfeited Discounts	7,318,368	7,486,736
17	(451) Miscellaneous Service Revenues	6,909,893	7,079,770
18	(453) Sales of Water and Water Power	12,154	26,406
19	(454) Rent from Electric Property	19,158,931	20,579,425
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	128,935,328	78,876,459
22	(456.1) Revenues from Transmission of Electricity of Others	63,697,983	75,553,244
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	226,031,657	189,602,040
27	TOTAL Electric Operating Revenues	4,353,766,380	4,494,585,986

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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
15,998,640	16,221,455	1,466,724	1,457,645	2
				3
16,194,257	16,055,182	213,730	210,217	4
19,934,268	21,494,710	34,070	34,172	5
144,765	141,122	3,948	4,080	6
437,595	449,314	13	13	7
				8
				9
52,709,525	54,361,783	1,718,485	1,706,127	10
12,349,061	12,344,976			11
65,058,586	66,706,759	1,718,485	1,706,127	12
				13
65,058,586	66,706,759	1,718,485	1,706,127	14

Line 12, column (b) includes $ 213,989,000 of unbilled revenues.

Line 12, column (d) includes 3,380,278 MWH relating to unbilled revenues

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.: 17 Column: b

(451) Miscellaneous Service Revenues include the following items that are $250,000 or greater:

Account service charge - disconnects/reconnects	$ 4,609,636
Customer contract flat rate billings	2,188,111

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

(456) Other Electric Revenues include the following items that are $250,000 or greater:

Renewable energy credit sales	$50,793,765
Demand-side management revenue	50,259,795
Energy exchange credits	8,415,849
Ancillary services	7,216,814
Steam sales	4,857,715
Flyash/by-product sales	3,238,868
Phase shifting equipment fee from WECC	1,271,449
Power sale and exchange agreements	1,091,292
Revenue from generation interconnection and transmission service request studies	840,474
Maintenance charges for work on transmission facilities	423,133
Net profit on sales of materials and supplies inventory	361,448

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

	Page 300 Year ended December 31, 2009	Page 304 Year ended December 31, 2009	Variance Year ended December 31, 2009	
Sales of Electricity				
Residential Sales - Account (440)	$ 1,346,519,773	$ 1,346,519,773	$ -	
Commercial and Industrial Sales - Account (442)				
Small (Commercial)	1,120,956,943	1,120,956,943	-	
Large (Industrial)	976,991,304	976,991,304	-	(a)
Public Street and Highway Lighting - Account (444)	20,913,398	20,913,398	-	
Other Sales to Public Authorities - Account (445)	19,032,148	19,032,148	-	
Sales to Railroads and Railways - Account (446)	-	-	-	
Interdepartmental Sales - Account (448)	-	-	-	
Total Sales to Ultimate Consumers	3,484,413,566	3,484,413,566	-	
Sales for Resale - Account (447)	643,321,157	-	643,321,157	(b)
Total Sales of Electricity	4,127,734,723	3,484,413,566	643,321,157	
(Less) Provision for Rate Refunds - Account (449.1)	-	-	-	
Total Revenues Net of Provisions for Refunds	4,127,734,723	3,484,413,566	643,321,157	

Other Operating Revenues

Forfeited Discounts - Account (450)	7,318,368	7,318,368	-
Miscellaneous Service Revenues - Account (451)	6,908,893	6,908,893	-
Sales of Water and Water Power - Account (453)	12,154	12,154	-
Rent from Electric Property - Account (454)	19,158,931	19,158,931	-
Interdepartmental Rents - Account (455)	-	-	-
Other Electric Revenues - Account (456)	128,935,328	124,707,208	4,228,120 (c)
Revenues from Transmission of Electricity of Others (456.1)	63,697,983	-	63,697,983 (b)
Total Operating Revenues	$ 4,353,766,380	$ 3,642,519,120	$ 711,247,260

(a) The large industrial line on page 300 includes account 442.2 Industrial Sales of $891,577,996 and account 442.3 Irrigation Sales of $85,413,308.

(b) Sales for Resale and Revenues from Transmission of Electricity of Others are not included on page 304 Sales of Electricity by Rate Schedules as the revenues are included in pages 310-311 Sales for Resale and pages 328-330 Transmission of Electricity for Others, respectively, in this Form No. 1.

(c) The variance in Other Electric Revenues-Account (456) is as follows:

	Page 300	Page 304	Variance
Steam Sales	$ 4,857,715	$ -	$ 4,857,715
Materials and Supplies Inventory Net Profit	(629,595)	-	(629,595)
Other Electric Revenues - Account (456)	124,707,208	124,707,208	-
TOTAL Other Electric Revenues - Account (456)	$ 128,935,328	$ 124,707,208	$ 4,228,120

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

The following is a reconciliation of the unbilled revenue accrual at December 31, 2009 and the reversal of the December 31, 2008 unbilled revenue accrual.

	December 31, 2009
Current year unbilled revenue accrual	$ 213,989,000
Prior year unbilled revenue accrual reversal	(210,896,000)
Change in unbilled revenue accrual	$ 3,093,000

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

The following is a reconciliation of the unbilled MWh accrual at December 31, 2009 and the reversal of the December 31, 2008 unbilled MWh accrual.

	December 31, 2009
Current year unbilled MWh accrual	3,380,278
Prior year unbilled MWh accrual reversal	(3,440,267)
Change in MWh accrual	(59,989)

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R-CA RES CHECK M			1		
4	06LNX00102-LINE EXT 80% G		78			
5	06LNX00109-REF/NREF ADV+		76			
6	06NETMT135 - CA RES NET	177	20,610	17	10,412	0.1164
7	06OALT015R-OUTD AR LGT SR	349	75,055	381	916	0.2151
8	06RESD000D-RES SRVC	204,930	23,437,545	19,282	10,628	0.1144
9	06RESDDL06-CA LOW INCOME	102,250	11,616,537	8,847	11,558	0.1136
10	06RESDDM9M-MULTI FAMILY	268	29,660	8	33,500	0.1107
11	06RESDDS8M-MULT FAM SBMET	1,348	125,920	13	103,692	0.0934
12	ACQUISITION COMMITMENT-A and		24,929			
13	ACQUISTION COMMITMENT-WEST		15,564			
14	REVENUE ADJUSTMENT -		-1,415,755			
15	SMUD REVENUE IMPUTATIONS		55,652			
16	06RESD00DN - CA RES SRVC -	99,451	11,274,738	7,680	12,949	0.1134
17	UNBILLED REV - UNCOLLECTIBLE		-4,000			
18	UNBILLED REVENUE	-2,174	-42,000			0.0193
19	IDAHO					
20	07LNX00010-MNTHLY 80%GUAR		980			
21	07LNX00035-ADV 80%MO GUAR		2,959			
22	07NETMT135 - ID RESIDENTIAL	706	52,570	37	19,081	0.0745
23	07OALCO007-CUST OWN LIGHT	10	3,697	1	10,000	0.3697
24	07OALT07AR-SECURITY AR LG	111	43,941	140	793	0.3959
25	07RESD0001-RES SRVC	411,012	36,891,331	40,583	10,128	0.0898
26	07RESD0001-RES SRVC		1,187			
27	07RESD0036-RES SRVC-OPTIO	309,965	22,414,057	16,132	19,214	0.0723
28	07RESD0036-RES SRVC-OPTI		-1,078			
29	BPA BALANCING ACCOUNT		-196,539			
30	UNBILLED REV - UNCOLLECTIBLE		-14,000			
31	ACQUISITION COMMITMENT-A and		110,935			
32	ACQUISITION		107,642			
33	SMUD REVENUE IMPUTATIONS		108,347			
34	UNBILLED REVENUE	-5,455	-279,000			0.0511
35	OREGON					
36	01CHCK000R-RES CHECK MTR			1		
37	01COST0004 - 01RESD0004	5,451,610	243,004,718			0.0446
38	01HABIT004 - 01RESD0004	45,848	1,991,222			0.0434
39	01LNX00102-LINE EXT 80% G		17,725			
40	01LNX00105-CNTRCT $ MIN G		12			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	01LNX00109-REF/NREF ADV +		5,875			
2	01NETMT135-NET METERING		286,682	621		
3	01NETMT135-NET METERING		-25,585			
4	01OALT014R-OUTD AR LGT RE	2,627	381,472	2,937	894	0.1452
5	01OALT014R-OUTD AR LGT RE		-10,526			
6	01PTOU0004 - 01RESD0004	21,868	977,608			0.0447
7	01RENEW004 - 01RESD0004	198,375	8,519,890			0.0429
8	01RESD0004-RES SRVC		244,164,792	470,808		
9	01RESD0004-RES SRVC		-21,975,532			
10	01RESD004T - RES Time Option		925,082	1,396		
11	01RESD004T - RES Time Option		-84,473			
12	01UPPL000R-BASE SCH FALL			4		
13	BPA BALANCING ACCOUNT		-1,352,633			
14	OR GAIN ON SALE OF ASSET		484,373			
15	OR SB408 RECOVERY		4,732,592			
16	OR SB838 RECOVERY		-3,431,715			
17	SMUD REVENUE IMPUTATIONS		735,070			
18	UNBILLED REV - UNCOLLECTIBLE		-45,000			
19	UNBILLED REVENUE	-68,449	-4,032,000			0.0589
20	UTAH					
21	08BLSKY01R-BLUESKY ENERGY		-1			
22	08CFR00001-MTH FACILITY S		1,409			
23	08CHCK000R-UT RES CHECK M			1		
24	08COOLKPRR - Utah Cool Keeper			80,033		
25	08LNX00001-MTHLY 80% GUAR		3,028			
26	08LNX00005- MNTHLY MIN GUAR		132			
27	08LNX00013-80% MTHLY MIN		29,226			
28	08LNX00016 - 80% annual		368			
29	08LNX00108-ANN COST MTHLY		3,589			
30	08MHTP0025-MOBILE HOME &	12,083	849,834	11	1,098,455	0.0703
31	08NETMT135 - Net Metering	3,067	261,179	406	7,554	0.0852
32	08OALT007R-SECURITY AR LG	2,881	801,864	3,180	906	0.2783
33	08PTLD000R-POST TOP LIGHT	115	8,654	33	3,485	0.0753
34	08RESD0001-RES SRVC	6,275,021	536,785,256	670,678	9,356	0.0855
35	08RESD0002-RES SRVC-OPTIO	2,877	242,642	339	8,487	0.0843
36	08RESD0003-LIFELINE PRGRM	210,578	17,758,808	26,634	7,906	0.0843
37	08UPPL000R-BASE SCH FALL			4		
38	SMUD REVENUE IMPUTATIONS		-128,533			
39	UNBILLED REV - UNCOLLECTIBLE		-62,000			
40	UNBILLED REVENUE	-10,935	-358,000			0.0327
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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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	WASHINGTON					
2	02LNX00109-REF/NREF ADV +		203			
3	02NETMT135 - WA RES NET	176	12,189	9	19,556	0.0693
4	02NETMT135 - WA RES NET		-556			
5	02OALTB15R-WA OUTD AR LGT	1,107	148,783	1,192	929	0.1344
6	02OALTB15R-WA OUTD AR LGT		-3,218			
7	02RESD0016-WA RES SRVC	1,627,647	117,731,011	99,334	16,386	0.0723
8	02RESD0016-WA RES SRVC		-4,816,545			
9	02RESD0017-BILL ASSISTANC	71,240	5,155,472	4,101	17,371	0.0724
10	02RESD0017-BILL ASSISTANCE		-212,576			
11	02RESD0018-WA 3 PHASE RES	2,668	210,785	95	28,084	0.0790
12	02RESD0018-WA 3 PHASE RES		-7,821			
13	02RESD018X-WA 3 PHASE RES	583	45,322	23	25,348	0.0777
14	02RESD018X-WA 3 PHASE RES		-1,694			
15	02RFNDCENT - CENTRALIA RFND		-3			
16	02ZZMERGCR-MERGER CREDITS		1			
17	ACQUISITION COMMITMENT-A and		275			
18	BPA BALANCING ACCOUNT		-1,905,297			
19	SMUD REVENUE IMPUTATIONS		196,762			
20	WASHINGTON - CHEHALIS		7,920,000			
21	UNBILLED REV - UNCOLLECTIBLE		-15,000			
22	UNBILLED REVENUE	-28,567	-1,556,000			0.0545
23	WYOMING					
24	05LNX00109-REF/NREF ADV +		1,973			
25	05NETMT135 - EXPERIMENTAL	634	51,176	44	14,409	0.0807
26	05OALT015R-OUTD AR LGT SR	952	146,586	1,116	853	0.1540
27	05RES00002-WY OPTIONAL		-24			
28	05RESD0002-WY RES SRVC	928,952	76,856,694	95,900	9,687	0.0827
29	05RESD018X-RES 3 PHASE SR	10	857	1	10,000	0.0857
30	ACQUISITION COMMITMENT-A and		179,869			
31	ACQUISITION		161,021			
32	SMUD REVENUE IMPUTATIONS		90,916			
33	UNBILLED REV - UNCOLLECTIBLE		-12,000			
34	UNBILLED REVENUE	-13,819	-1,028,000			0.0744
35	05RESD0002-WY RES SRVC	136,508	11,194,392	12,588	10,844	0.0820
36	05UPPL000R-BASE SCH FALL			1		
37	09OALT207R-SECURITY AR LG	82	23,350	97	845	0.2848
38	05NETMT135 - EXPERIMENTAL	221	16,915	8	27,625	0.0765
39	09RES00002			2		
40	09RESD0002	-6	-787	4	-1,500	0.1312
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	UNBILLED REVENUE	-262	6,000			-0.0229
2	LESS MULTIPLE BILLINGS			-97,999		
3						
4	TOTAL RESIDENTIAL SALES	15,998,640	1,346,519,773	1,466,724	10,908	0.0842
5						
6	COMMERCIAL SALES					
7	CALIFORNIA					
8	06CHCK000N-CA NRES CHECK			1		
9	06GNSV0025-CA GEN SRVC	61,986	8,469,437	6,893	8,993	0.1366
10	06GNSV025F-GEN SRVC-< 20	907	139,139	92	9,859	0.1534
11	06GNSV0A32-GEN SRVC-20 KW	79,584	9,002,037	923	86,223	0.1131
12	06LGSV048T-LRG GEN SERV	69,161	5,071,910	11	6,287,364	0.0733
13	06LGSV0A36-LRG GEN SRVC-O	84,475	7,963,331	190	444,605	0.0943
14	06LNX00102-LINE EXT 80% G		12,260			
15	06LNX00103-LINE EXT 80% G		298			
16	06LNX00105-CNTRCT $ MIN G		4,596			
17	06LNX00109-REF/NREF ADV +		80,322			
18	06LNX00300 - 80% MONTHLY MIN		9,237			
19	06LNX00311 - LINE EXT 80%		2,870			
20	06NMT36135-CA GEN SVC NET	34	3,559	1	34,000	0.1047
21	06OALT015N-OUTD AR LGT SR	742	160,944	539	1,377	0.2169
22	06RCFL0042-AIRWAY & ATHLE	223	36,039	38	5,868	0.1616
23	06WHSV0031-COMM WTR HEATI	194	22,807	28	6,929	0.1176
24	06NMT25135-CA GEN SVC NET			1		
25	06NMT32135-CA GEN SVC NET	117	13,636	2	58,500	0.1165
26	ACQUISITION COMMITMENT-A and		18,404			
27	ACQUISITION		11,490			
28	REVENUE ADJUSTMENT -		-1,029,682			
29	SMUD REVENUE IMPUTATIONS		41,085			
30	06LNX00110-REF/NREF ADV +		6,630			
31	UNBILLED REVENUE	2,802	401,000			0.1431
32	IDAHO					
33	07CISH0019-COMM & IND SPA	7,506	504,657	131	57,298	0.0672
34	07GNSV0006-GEN SRVC-LRG P	192,961	12,513,109	943	204,625	0.0648
35	07GNSV0009-GEN SRVC-HI VO	39,816	1,787,561	1	39,816,000	0.0449
36	07GNSV0023-GEN SRVC-SML P	122,135	9,759,831	6,163	19,817	0.0799
37	07GNSV0035-GEN SRVCOPTION	515	26,310	2	257,500	0.0511
38	07GNSV006A-GEN SRVC-LRG P	28,892	1,998,210	214	135,009	0.0692
39	07GNSV023A-GEN SRVC-SML P	16,059	1,323,081	1,155	13,904	0.0824
40	07GNSV023F-GEN SRVC SML P	18	2,634	7	2,571	0.1463
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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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	07LNX00010-MNTHLY 80%GUAR		10,998			
2	07LNX00035-ADV 80%MO GUAR		327,533			
3	07LNX00040-ADV+REFCHG+80%		70,822			
4	07OALT007N-SECURITY AR LG	248	90,876	186	1,333	0.3664
5	07OALT07AN-SECURITY AR LG	12	4,713	14	857	0.3928
6	07LNX00312 - ID LINE EXT		3,911			
7	07NMT23135 - ID NET MTR -	49	3,870	2	24,500	0.0790
8	07LNX00015-ANNUAL 80%GUAR		3,440			
9	07LNX00311 - LINE EXT 80%		38,490			
10	07LNX00020 - ID MONTHLY		722			
11	07LNX00300 - 80% MONTHLY MIN		2,762			
12	ACQUISITION COMMITMENT-A and		64,495			
13	ACQUISITION		62,581			
14	BPA BALANCING ACCOUNT		40,396			
15	SMUD REVENUE IMPUTATIONS		60,241			
16	UNBILLED REVENUE	26,785	1,733,000			0.0647
17	OREGON					
18	01COST0023, OR GEN SRV, COST	982,083	44,445,674			0.0453
19	01COST0048 - 01LGSV0048	765,969	31,518,399			0.0411
20	01COST023F - OR GEN SRV -	3,300	158,204			0.0479
21	01COSTB023 - OR GEN SRV,	89,287	4,178,237			0.0468
22	01COSTL030 - OR LRG GEN SRV,	1,080,312	46,647,204			0.0432
23	01COSTS028, OR GEN SERV,	1,938,364	86,139,943			0.0444
24	01COSTS030 - OR GEN SRV CBS >	1,195	42,031			0.0352
25	01GNSB0023 - BPA DISC, < 30 kW		-346,826			
26	01GNSB0023, OR GEN SRV, BPA, <		4,959,174	14,375		
27	01GNSB0028 - OR GEN SRVC,		-520,063			
28	01GNSB0028, OR GEN SRV, BPA, >		2,767,720	568		
29	01GNSB023T - OR GEN SRV - TOU		27,446	53		
30	01GNSB023T - OR GEN SRVC,		-2,601			
31	01GNSV0023, OR GEN SRV, < 30		36,056,822	55,970		
32	01GNSV0028, OR GEN SRV > 30		39,545,373	9,024		
33	01GNSV023F - OR GEN SRV - FLAT	10,784	1,335,862	830	12,993	0.1239
34	01GNSV023M - OR GEN SRV,	19	1,622	1	19,000	0.0854
35	01GNSV023T, OR GEN SRV, TOU		152,595	237		
36	01HABT0023, OR HABITAT	2,327	106,619			0.0458
37	01HABTB023 - OR HABITAT	191	9,053			0.0474
38	01LGSB0030, GEN DEL SRV, > 200		-216,836			
39	01LGSB0030, GEN DEL SRV, > 200		793,713	30		
40	01LGSV0030 - OR LRG GEN SRV, >		16,556,310	662		
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	01LGSV0048-1000KW AND OVR		7,745,775	96		
2	01LGSV048M-LRG GEN SRVC 1	53,302	2,435,620	1	53,302,000	0.0457
3	01LNX00100-LINE EXT 60% G		5,221			
4	01LNX00102-LINE EXT 80% G		515,358			
5	01LNX00103-LINE EXT 80% G		3,276			
6	01LNX00105-CNTRCT $ MIN G		16,195			
7	01LNX00109-REF/NREF ADV +		1,927,031			
8	01LNX00110-REF/NREF ADV +		9,183			
9	01LNX00300 - LINE EXT 80%		124,552			
10	01LNX00311 - LINE EXT 80% G		81,021			
11	01LPRS047M-PART REQ SRVC	3,956	401,630	3	1,318,667	0.1015
12	01NMT23135 - OR NET MTR, GEN,		39,974	63		
13	01OALT014N-OUTD AR LGT NR	1,630	245,116	1,175	1,387	0.1504
14	01OALT014N-OUTD AR LGT NR		-6,306			
15	01OALT015N-OUTD AR LGT NR	6,148	791,688	3,110	1,977	0.1288
16	01PTOU0023, OR GEN SRV, TOU	3,842	171,176			0.0446
17	01PTOUB023, OR GEN SRV, TOU	695	30,234			0.0435
18	01RCFL0054-REC FIELD LGT	1,029	91,700	102	10,088	0.0891
19	01RENW0023, OR RENW USAGE	9,058	416,939			0.0460
20	01RENWB023 - OR RENEWABLE	547	26,045			0.0476
21	01STDAY023 - OR DAY STD OFR,	1,919	74,580			0.0389
22	01STDAY028 - OR DAY STD OFF,	7,040	270,547			0.0384
23	01STDAY030 - OR STD DAY OFF,	4,520	172,938			0.0383
24	01UPPL000N-BASE SCH FPACI		70			
25	BPA BALANCING ACCOUNT		-68,282			
26	01LGSB0048 - LG GEN SVC >		-13,518			
27	01LGSB0048 - LG GEN SVC >		48,289	1		
28	01NMT28135 - OR NET MTR, GEN,		121,901	26		
29	01NMT30135 - OR NET MTR, GEN,		96,640	4		
30	01LGSV028M - OR LGSV, <1000	602	41,313	1	602,000	0.0686
31	01GNSV030M - OR GEN SRV, 200	1,600	92,647	1	1,600,000	0.0579
32	01GNSV0728 - OR GEN SVC DIR		68,880	6		
33	01GNSV0730 -OR GEN SVC DIR		823,608	32		
34	01GNSV0748 LG GEN SVC DIR		2,600	2		
35	OR GAIN ON SALE OF ASSET		435,013			
36	OR SB408 RECOVERY		4,144,707			
37	OR SB 838 RECOVERY		-2,795,590			
38	SMUD REVENUE IMPUTATIONS		641,871			
39	UNBILLED REVENUE	39,405	3,634,000			0.0922
40	UTAH					
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	08CFR00051-MTH FAC SRVCHG		44,574			
2	08CFR00052-ANN FAC SVCCHG		2			
3	08COOLKPRN - A/C DIRECT LOAD			2,700		
4	08GNSV0006-GEN SRVC-DISTR	4,710,604	318,094,298	10,923	431,256	0.0675
5	08GNSV0009-GEN SRVC-HI VO	274,239	12,496,244	23	11,923,435	0.0456
6	08GNSV0023-GEN SRVC-DISTR	1,229,433	98,632,772	68,368	17,983	0.0802
7	08GNSV006A-GEN SRVC-ENERG	189,922	17,292,018	1,746	108,775	0.0910
8	08GNSV006B-GEN SRVC-DEM&	8,780	651,963	19	462,105	0.0743
9	08GNSV006M-MNL DIST VOLTG	3,691	200,889	7	527,286	0.0544
10	08GNSV009A-GEN SRVC HI VO	23,880	1,178,864	2	11,940,000	0.0494
11	08GNSV009M-MANL HIGH VOLT	1,672	63,865			0.0382
12	08GNSV023F-GEN SRVC FIXED	1,407	155,508	132	10,659	0.1105
13	08GNSV023M-GNSV DIST VOLT	106	8,778	6	17,667	0.0828
14	08GNSV06AM-MNL ENERGY TOD	180	30,307	1	180,000	0.1684
15	08GNSV06MN-GNSV DIST VOLT	26,303	1,628,817	440	59,780	0.0619
16	08LNX00002-MTHLY 80% GUAR		566,792			
17	08LNX00004-ANNUAL 80%GUAR		5,910			
18	08LNX00006-FIXD MTHLY MIN		16,639			
19	08LNX00014-80% MIN MNTHLY		2,207,051			
20	08LNX00017-ADV/REF&80%ANN		144,106			
21	08LNX00158-ANNUALCOST MTH		33,817			
22	08LNX00300 - LINE EXT 80% PLUS		143,760			
23	08LNX00310 - IRR, 80% ANNUAL		188			
24	08LNX00312 UT IRG LINE EXT		7,491			
25	08NMT06135 - UT NET MTR, GEN,	3,905	268,482	6	650,833	0.0688
26	08NMT08135 -NET METERING GEN	5,433	315,497	1	5,433,000	0.0581
27	08NMT23135 - UT NET MTR, GEN,	472	40,728	36	13,111	0.0863
28	08OALT007N-SECURITY AR LG	8,859	2,001,520	4,611	1,921	0.2259
29	08POLE0075-POLES W/LIGHT		12	1		
30	08PRSV031M-BKUP MNT&SUPPL	10,125	647,240	2	5,062,500	0.0639
31	08PTLD000N-POST TOP LIGHT	38	2,851	5	7,600	0.0750
32	08TOSS015F-TRAFFIC SIG NM	220	18,704	32	6,875	0.0850
33	08TOSS0015-TRAF & OTHER S	1,164	103,126	496	2,347	0.0886
34	08MONL0015-MTR OUTDONIGHT	12,794	886,457	326	39,245	0.0693
35	SMUD REVENUE IMPUTATIONS		-148,498			
36	08LNX00311 - LINE EXT 80%		188,519			
37	08GNSV0008 - UT GEN SVC TOU >	921,584	53,511,819	141	6,536,057	0.0581
38	08GNSV008M - UT GEN SVC TOU >	34,238	2,112,817	5	6,847,600	0.0617
39	UNBILLED REVENUE	19,106	1,926,000			0.1008
40	WASHINGTON					
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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1	02GNSB0024-WA GEN SRVC DO	42,138	3,255,593	3,194	13,193	0.0773
2	02GNSB0024-WA GEN SRVC DO		-123,173			
3	02GNSB024F-GEN SRVC DOM/F	154	15,211	6	25,667	0.0988
4	02GNSB024F-GEN SRVC DOM/F		-2			
5	02GNSB24FP-WA GEN SVC	185	95,242	101	1,832	0.5148
6	02GNSB24FP-WA GEN SVC		-570			
7	02GNSV0024-WA GEN SRVC	479,283	33,920,784	14,128	33,924	0.0708
8	02GNSV024F-WA GEN SRVC-FL	1,117	118,796	113	9,885	0.1064
9	02LGSB0036-LRG GEN SVC IRG	81,058	4,775,727	94	862,319	0.0589
10	02LGSB0036-LRG GENSVC IRG		-241,236			
11	02LGSV0036-WA LRG GEN SRV	713,397	42,892,027	836	853,346	0.0601
12	02LGSV048T-LRG GEN SRVC 1	135,161	7,383,037	25	5,406,440	0.0546
13	02LNX00102-LINE EXT 80% G		65,142			
14	02LNX00103-LINE EXT 80% G		6,579			
15	02LNX00105-CNTRCT $ MIN G		-596			
16	02LNX00109-REF/NREF ADV +		327,338			
17	02LNX00110-REF/NREF ADV +		13,155			
18	02LNX00112-YR INCURRED CH		669			
19	02LNX00300-LINE EXT 80% G		2,663			
20	02LNX00310 - IRG, 80% ANNUAL		2,685			
21	02LNX00311 - LINE EXT 80%		23,939			
22	02OALT015N-WA OUTD AR LGT	1,671	207,735	863	1,936	0.1243
23	02OALTB15N-WA OUTD AR LGT	613	81,808	538	1,139	0.1335
24	02OALTB15N-WA OUTD AR LGT		-1,788			
25	02RCFL0054-WA REC FIELD L	259	21,297	29	8,931	0.0822
26	02RFNDCENT - CENTRALIA RFND		5			
27	02ZZMERGCR-MERGER CREDITS		2			
28	02NMT24135, Net metering, WA	71	5,270	3	23,667	0.0742
29	02NMT36135-WA NET METER LRG	36	3,299	1	36,000	0.0916
30	ACQUISITION COMMITMENT-A and		244			
31	BPA BALANCING ACCOUNT		-143,821			
32	SMUD REVENUE IMPUTATIONS		170,832			
33	WASHINGTON - CHEHALIS		6,120,000			
34	UNBILLED REVENUE	25,266	1,683,000			0.0666
35	WYOMING					
36	05CHCK000N-WY NRES			1		
37	05GNSC0025 - WY SMALL	87	6,119	14	6,214	0.0703
38	05GNSV0025-WY GEN SRVC	532,548	38,153,917	18,008	29,573	0.0716
39	05GNSV0028-GEN SVC > 15 KW	577,716	42,333,671	4,475	129,099	0.0733
40	05GNSV025F-GEN SRVC-FL RA	987	125,909	190	5,195	0.1276
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
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1	05LGSV0046-WY LRG GEN SRV	180,748	10,313,334	19	9,513,053	0.0571
2	05LGSV046M-WY LRG GEN SERV	36,691	2,025,659	1	36,691,000	0.0552
3	05LGSV048T-LRG GENSRV TIM	9,898	582,181	1	9,898,000	0.0588
4	05LNX00100-LINE EXT 60% G		46			
5	05LNX00102-LINE EXT 80% G		513,295			
6	05LNX00103-LINE EXT 80%		808			
7	05LNX00105-CNTRCT $ MIN G		5,343			
8	05LNX00109-REF/NREF ADV +		635,421			
9	05LNX00110-REF/NREF ADV+		580			
10	05LNX00114-TEMP SVC 12MO>		5,076			
11	05NMT25135 - WY NET MTR, GEN,	243	20,200	5	48,600	0.0831
12	05NMT28135-NET MTR SMALL	381	36,040	4	95,250	0.0946
13	05OALT015N-OUTD AR LGT SR	2,944	449,626	1,764	1,669	0.1527
14	05RCFL0054-WY REC FIELD L	683	54,614	52	13,135	0.0800
15	05LNX00300 - LINE EXT 80%		225,224			
16	05LNX00311 - LINE EXT 80%		44,341			
17	ACQUISITION COMMITMENT-A and		246,065			
18	ACQUISITION		220,280			
19	SMUD REVENUE IMPUTATIONS		126,750			
20	UNBILLED REVENUE	-6,656	-140,000			0.0210
21	05GNSC0025 - WY SMALL	25	1,630	3	8,333	0.0652
22	05GNSV0025 - WY GEN SRVC	72,639	5,112,017	2,209	32,883	0.0704
23	05GNSV0028-GEN SVC > 15 KW	68,820	5,073,601	645	106,698	0.0737
24	05GNSV025F-GEN SRVC-FL RA	191	18,758	32	5,969	0.0982
25	05GNSV028M-GEN SVC > 15 KW	1,098	75,362	1	1,098,000	0.0686
26	05LNX00102-LINE EXT 80% G		6,415			
27	05LNX00109-REF/NREF ADV +		146,890			
28	05LNX00110-REF/NREF ADV +		840			
29	05LNX00114-TEMP SVC		335			
30	09GNSV0025-GEN SVC-SINGLE	-20	-19,669	2	-10,000	0.9835
31	09GNSV025F-GEN SVC-FIXED	3	288	6	500	0.0960
32	09GNSV025M-GEN SVC-MANUAL	981	66,190	1	981,000	0.0675
33	05NMT25135 - WY NET MTR, GEN,	45	2,747	1	45,000	0.0610
34	05NMT28135-NET MTR SMALL	63	4,576	1	63,000	0.0726
35	09OALT207N-SECURITY AR LG	267	70,810	143	1,867	0.2652
36	09MONL0213-WY MTR OUTDOOR	6	1,051	2	3,000	0.1752
37	09SLCU2123-MTR OUTDONIGHT	7	444	2	3,500	0.0634
38	05LNX00300 - LINE EXT 80%		32,608			
39	05LNX00311 - LINE EXT 80%		5,822			
40	UNBILLED REVENUE	953	116,000			0.1217
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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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	LESS MULTIPLE BILLINGS			-27,722		
2						
3	TOTAL COMMERCIAL SALES	16,194,257	1,120,956,943	213,730	75,770	0.0692
4						
5	INDUSTRIAL SALES					
6	CALIFORNIA					
7	06GNSV0025-CA GEN SRVC	599	87,146	93	6,441	0.1455
8	06GNSV0A32-GEN SRVC-20 KW	1,904	244,988	29	65,655	0.1287
9	06LGSV048T-LRG GEN SERV	39,534	2,885,422	5	7,906,800	0.0730
10	06LGSV0A36-LRG GEN SRVC-O	5,247	554,742	15	349,800	0.1057
11	06LNX00109-REF/NREF ADV +		1,482			
12	ACQUISITION COMMITMENT-A and		3,935			
13	ACQUISITION		2,457			
14	REVENUE ADJUSTMENT -		-195,132			
15	SMUD REVENUE IMPUTATIONS		7,862			
16	UNBILLED REVENUE	-1,032	-40,000			0.0388
17	IDAHO					
18	07CFR00001-MTH FACILITY S		2,011			
19	07CISH0019-COMM & IND	153	10,824	3	51,000	0.0707
20	07GNS80006-IDAHO GEN	669	37,700	1	669,000	0.0564
21	07GNSV0006-GEN SRVC-LRG P	96,219	5,319,611	118	815,415	0.0553
22	07GNSV0008-GEN SRVC-MEDIU	328	17,182	1	328,000	0.0524
23	07GNSV0009-GEN SRVC-HI VO	73,460	3,483,571	11	6,678,182	0.0474
24	07GNSV0023-GEN SRVC-SML P	9,383	733,412	353	26,581	0.0782
25	07GNSV0035-GEN SRVCOPTION	1,234	57,879	1	1,234,000	0.0469
26	07GNSV006A-GEN SRVC-LRG P	4,841	328,112	32	151,281	0.0678
27	07GNSV023A-GEN SRVC-SML P	2,098	191,327	247	8,494	0.0912
28	07GNSV023S-IDAHO TRAFFIC	8	1,101	3	2,667	0.1376
29	07LNX00035-ADV 80%MO GUAR		1,525			
30	07LNX00108-ANN COST MTHLY		1,996			
31	07LNX00300 - 80% MONTHLY MIN		2,723			
32	07OALT007N-SECURITY AR LG	13	4,805	17	765	0.3696
33	07OALT07AN-SECURITY AR LG	2	706	3	667	0.3530
34	07SPCL0001	1,015,300	44,056,231	1	1,015,300,000	0.0434
35	07SPCL0002	89,536	3,697,685	1	89,536,000	0.0413
36	ACQUISITION COMMITMENT-A and		275,815			
37	ACQUISITION		267,629			
38	BPA BALANCING ACCOUNT		1,942			
39	SMUD REVENUE IMPUTATIONS		249,187			
40	UNBILLED REVENUE	8,284	321,000			0.0387
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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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	OREGON					
2	01COST0023, OR GEN SRV, COST	20,779	944,948			0.0455
3	01COST0048 - 01LGSV0048	1,278,099	51,846,060			0.0406
4	01COST023F - OR GEN SRV -	3	168			0.0560
5	01COSTB023 - OR GEN SRV,	400	18,584			0.0465
6	01COSTL030 - OR LRG GEN SRV,	190,973	8,305,961			0.0435
7	01COSTS028, OR GEN SERV,	99,307	4,411,299			0.0444
8	01GNSB0023 - BPA DISC, < 30		-1,526			
9	01GNSB0023, OR GEN SRV, BPA, <		24,669	65		
10	01GNSB0028 - OR GEN SRVC,		-2,565			
11	01GNSB0028, OR GEN SRV, BPA, >		20,253	6		
12	01GNSV0023, OR GEN SRV, < 30		816,718	1,146		
13	01GNSV0028, OR GEN SRV > 30		2,647,912	516		
14	01GNSV023F - OR GEN SRV - FLAT	3	850	3	1,000	0.2833
15	01GNSV023M - OR GEN SRV,	14	2,292	1	14,000	0.1637
16	01GNSV023T, OR GEN SRV, TOU		2,805	4		
17	01HABT0023, OR HABITAT	4	201			0.0503
18	01LGSV0030 - OR LRG GEN SRV, >		4,548,369	165		
19	01LGSV0048-1000KW AND OVR		12,386,712	108		
20	01LGSV048M-LRG GEN SRVC 1	490,770	21,669,676	6	81,795,000	0.0442
21	01LNX00102-LINE EXT 80% G		3,904			
22	01LNX00105-CNTRCT $ MIN		1,659			
23	01LNX00109-REF/NREF ADV		663			
24	01LNX00300 - LINE EXT 80%		21,491			
25	01LPRS047M-PART REQ	395,217	17,706,309	4	98,804,250	0.0448
26	01NMT28135 - OR NET MTR, GEN,		6,422	2		
27	01OALT014N-OUTD AR LGT NR	5	611	5	1,000	0.1222
28	01OALT014N-OUTD AR LGT		-18			
29	01OALT015N-OUTD AR LGT	358	44,064	148	2,419	0.1231
30	01PTOU0023, OR GEN SRV, TOU	64	2,848			0.0445
31	01RENW0023, OR RENW USAGE	226	10,343			0.0458
32	01RENWB023 - OR RENEWABLE		23			
33	BPA BALANCING ACCOUNT		-283			
34	01STDAY023 - OR DAY STD OFR,	31	1,200			0.0387
35	OR GAIN ON SALE OF ASSET		300,645			
36	OR SB 408 RECOVERY		2,676,175			
37	OR SB 838 RECOVERY		-1,632,118			
38	SMUD REVENUE IMPUTATIONS		388,340			
39	UNBILLED REVENUE	5,975	1,052,000			0.1761
40	UTAH					
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	08CFR00051-MTH FAC SRVCHG		15,948			
2	08EFOP0021-ELEC FURNACE O	1,960	147,704	2	980,000	0.0754
3	08EFOP021M-ELEC FURNACE O	1,176	135,521	3	392,000	0.1152
4	08GNSV0006-GEN SRVC-DISTR	689,915	50,067,071	1,239	556,832	0.0726
5	08GNSV0009-GEN SRVC-HI VO	2,569,357	109,132,227	112	22,940,688	0.0425
6	08GNSV0023-GEN SRVC-DISTR	61,032	4,966,984	3,705	16,473	0.0814
7	08GNSV006A-GEN SRVC-ENERG	49,619	4,829,373	248	200,077	0.0973
8	08GNSV006B-GEN	6,969	511,429	10	696,900	0.0734
9	08GNSV009A-GEN SRVC HI VO	15,183	1,019,312	6	2,530,500	0.0671
10	08GNSV009M-MANL HIGH	970,492	38,376,088	11	88,226,545	0.0395
11	08GNSV023F-GEN SRVC FIXED	4	1,656	1	4,000	0.4140
12	08GNSV06MN-GNSV DIST VOLT	1,165	83,183	30	38,833	0.0714
13	08GNSV09AM-MAN TOD HIVOLT	1,262	106,993	1	1,262,000	0.0848
14	08LNX00002-MTHLY 80% GUAR		23,777			
15	08LNX00004-ANNUAL 80%GUAR		12,464			
16	08LNX00014-80% MIN		73,478			
17	08LNX00017-ADV/REF&80%ANN		3,410			
18	08LNX00311 - LINE EXT 80%		1,660			
19	08LNX00300 - LINE EXT 80% PLUS		99,349			
20	08LNX00310 - IRR, 80% ANNUAL		6			
21	08OALT007N-SECURITY AR	1,471	305,190	519	2,834	0.2075
22	08TOSS0015-TRAF & OTHER S	32	2,574	9	3,556	0.0804
23	08MONL0015-MTR OUTDONIGHT	12	2,763	6	2,000	0.2303
24	08NMT23135 - UT NET MTR,GEN,	62	4,026	1	62,000	0.0649
25	08SPCL0001	363,446	14,459,495	1	363,446,000	0.0398
26	08SPCL0002	695,212	19,125,460	1	695,212,000	0.0275
27	08SPCL0003	778,970	26,953,532	1	778,970,000	0.0346
28	08SPCL0005	253,662	9,281,595	1	253,662,000	0.0366
29	SMUD REVENUE IMPUTATIONS		-164,928			
30	08GNSV06AM-MNL ENERGY TOD	189	20,505	2	94,500	0.1085
31	08GNSV0008 - UT GEN SVC TOU >	887,483	54,512,084	114	7,784,939	0.0614
32	08GNSV008M - UT GEN SVC TOU >	60,130	3,578,503	7	8,590,000	0.0595
33	UNBILLED REVENUE	-10,914	1,058,000			-0.0969
34	WASHINGTON					
35	02GNSB0024-WA GEN SRVC	2,760	206,876	98	28,163	0.0750
36	02GNSB0024-WA GEN SRVC DO		-7,726			
37	02GNSB24FP-WA GEN SVC	5	1,899	1	5,000	0.3798
38	02GNSB24FP-WA GEN SVC		-13			
39	02GNSV0024-WA GEN SRVC	16,583	1,199,690	370	44,819	0.0723
40	02GNSV024F-WA GEN	33	6,647	4	8,250	0.2014
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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1	02LGSV0036-WA LRG GEN SRV	128,361	7,853,744	123	1,043,585	0.0612
2	02LGSV048M-WA LRG GEN SRV	17,243	1,224,200	1	17,243,000	0.0710
3	02LGSV048T-LRG GEN SRVC 1	660,556	31,950,527	32	20,642,375	0.0484
4	02OALT015N-WA OUTD AR LGT	119	13,846	42	2,833	0.1164
5	02OALTB15N-WA OUTD AR LGT	29	3,830	18	1,611	0.1321
6	02OALTB15N-WA OUTD AR LGT		-81			
7	02PRSV47TM-LRG PART REQMT	1,540	167,035	1	1,540,000	0.1085
8	02LGSB0036-LRG GEN SVC IRG	4,581	430,088	29	157,966	0.0939
9	02LGSB0036-LRG GENSVC IRG		-13,424			
10	ACQUISITION COMMITMENT-A and		182			
11	BPA BALANCING ACCOUNT		-8,560			
12	SMUD REVENUE IMPUTATIONS		105,570			
13	WASHINGTON - CHEHALIS		3,060,000			
14	UNBILLED REVENUE	16,578	1,224,000			0.0738
15	WYOMING					
16	05GNSV0025-WY GEN SRVC	124,314	7,996,854	1,247	99,690	0.0643
17	05GNSV0028-GEN SRVC > 15 KW	161,489	10,332,054	567	284,813	0.0640
18	05GNSV025F-GEN SRVC-FL RA	41	4,447	9	4,556	0.1085
19	05LGSV0046-WY LRG GEN	1,414,349	75,513,111	55	25,715,436	0.0534
20	05LGSV046M-WY LRG GEN	257,076	13,010,600	2	128,538,000	0.0506
21	05LGSV048M-TOU>1000KW MAN	1,227,254	50,339,493	3	409,084,667	0.0410
22	05LGSV048T-LRG GENSRV TIM	1,154,020	47,902,084	10	115,402,000	0.0415
23	05LNX00100-LINE EXT 60% G		34,628			
24	05LNX00102-LINE EXT 80% G		195,024			
25	05LNX00105-CNTRCT $ MIN G		48,277			
26	05LNX00109-REF/NREF ADV +		125,478			
27	05OALT015N-OUTD AR LGT SR	88	12,350	46	1,913	0.1403
28	05PRSV033M-PART SERV REQ	851,027	43,455,703	4	212,756,750	0.0511
29	ACQUISITION COMMITMENT-A and		1,099,870			
30	ACQUISITION		984,617			
31	SMUD REVENUE IMPUTATIONS		557,577			
32	05LNX00300 - LINE EXT 80%		27,315			
33	UNBILLED REVENUE	-58,285	-2,857,000			0.0490
34	05GNSV0025-WY GEN SRVC	15,953	1,102,839	311	51,296	0.0691
35	05GNSV0028-GEN SVC > 15 KW	20,972	1,422,569	94	223,106	0.0678
36	05GNSV025M - General Service	75	6,574	1	75,000	0.0877
37	05GNSV028M-GEN SVC > 15 KW	3,288	174,821	4	822,000	0.0532
38	05LGSV0046-WY LRG GEN SRV	29,444	1,771,952	4	7,361,000	0.0602
39	05LGSV048M-TOU>1000KW MAN	328,405	13,568,473	3	109,468,333	0.0413
40	05LGSV048T-LRG GENSRV	1,055,644	45,089,419	9	117,293,778	0.0427
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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1	05LNX00102-LINE EXT 80% G		18			
2	05LNX00109-REF/NREF ADV		11			
3	05PRSV033M-PART SERV REQ	45,571	2,307,902	3	15,190,333	0.0506
4	09GNSV0025-GEN SVC-SINGLE	-139	-11,288			0.0812
5	09GNSV025M-GEN SVC-MANUAL	2,256	122,705	3	752,000	0.0544
6	09OALT207N-SECURITY AR	5	1,057	3	1,667	0.2114
7	09PRSV033M	365	105,160	1	365,000	0.2881
8	UNBILLED REVENUE	2,583	124,000			0.0480
9	LESS MULTIPLE BILLINGS			-1,258		
10						
11	TOTAL INDUSTRIAL SALES	18,712,080	891,577,996	10,983	1,703,731	0.0476
12						
13	IRRIGATION SALES					
14	CALIFORNIA					
15	06APSV0020-AG PMP SRVC	66,143	6,987,098	1,353	48,886	0.1056
16	06LNX00102-LINE EXT 80% G		961			
17	06LNX00103-LINE EXT 80% G		8,351			
18	06LNX00110-REF/NREF ADV +		40,825			
19	06LNX00310 - IRG, 80% ANNUAL		553			
20	06LNX00312 - CA IRG LINE EXT		693			
21	06USBR0040-KLAM IRG ONPRJ	26,820	2,404,084	671	39,970	0.0896
22	06LNX00109-REF/NREF ADV +		247			
23	IRRIGATION UNBILLED	-2				
24	IDAHO					
25	07APSA010L - IRG & Pump BPA		-826			
26	07APSA010L - IRG & Pump Large	391,887	28,925,349	3,247	120,692	0.0738
27	07APSA010S - IRG & PUMP BPA		-912			
28	07APSA010S - IRG & Pump Small	4,066	379,529	400	10,165	0.0933
29	07APSAL10X - IRG & PUMP - Large	73,169	5,513,630	788	92,854	0.0754
30	07APSAS10X - IRG & PUMP - Small	1,663	169,036	219	7,594	0.1016
31	07APSB010L - IRG & Pump BPA		285			
32	07APSB010L - IRG & Pump Large	-7	-873			0.1247
33	07APSC010L - IRG PUMP Srv BPA		492			
34	07APSC010L - IRG PUMP Srv Large	-11	-1,096			0.0996
35	07APSCL10X - IRG&PUMP LARGE		-9			
36	07APSVCNLL-LRG LOAD CANAL	25,857	1,728,923	81	319,222	0.0669
37	07APSVCNLS-SML LOAD CANAL	147	13,262	18	8,167	0.0902
38	07LNX00015-ANNUAL 80%GUAR		5,943			
39	07LNX00040-ADV+REFCHG+80%		186,950			
40	07LNX00107-SUBD ADV & AIC		1,097			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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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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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	07LNX00310 80% ANNUAL		1,185			
2	07LNX00312 - ID LINE EXT		18,501			
3	07APSN010L - ID LG IRR & PUMP	3,145	262,487	51	61,667	0.0835
4	07APSN010S - IRRIGATION,	336	28,025	17	19,765	0.0834
5	07APSNS10X - IRRIGATION,	3	702	2	1,500	0.2340
6	07ZZMERGCR-MERGER CREDITS		-1			
7	IRRIGATION BPA BAL ACCT		309,762			
8	UNBILLED REV - IRRIGATION	5				
9	OREGON					
10	01APSV0041-AG PMP SRVC BP		1,866,458	4,696		
11	01APSV0041-AG PMP SRVC BP		-167,941			
12	01APSV041L-OR Pumping Serv		2,620,778	1,101		
13	01APSV041L-OR Pumping Serv BPA		-284,328			
14	01APSV041T - AGR PUMP SRV		-2,324			
15	01APSV041T - AGR PUMP		27,259	59		
16	01APSV041X-AG PMP SRVC		83,828	248		
17	01APSV41XL-OR Pumping Serv no		163,644	55		
18	01BPADEBIT-BPA ADJUST FEE		36,673			
19	01COST0041 -01APSV0041	130,370	5,800,578			0.0445
20	01COST0048 - 01LGSV0048	8,412	340,126			0.0404
21	01COSTS028, OR GEN SERV,	230	10,477			0.0456
22	01GNSV0028, OR GEN SRV > 30		6,038	2		
23	01HABIT041 - 01APSV0041 AG	4	194			0.0485
24	01LGSB0048 - LG GEN SVC >		-31,372			
25	01LGSB0048 - LG GEN SVC >		71,829	1		
26	01LNX00102-LINE EXT 80% G		84			
27	01LNX00103-LINE EXT 80% G		18,749			
28	01LNX00109-REF/NREF ADV +		6,324			
29	01LNX00110-REF/NREF ADV +		115,656			
30	01LNX00310-LINE EXTENSION		2,392			
31	01PTOU0041 - 01APSV0041 AG	657	25,756			0.0392
32	01RENEW041 - 01APSV0041 AG	120	5,406			0.0451
33	01SLX00005-KLAMATH FALLS		180,210			
34	01SLX00013-K FALLS IRG MI		9,033			
35	01SLX00014-K FALLS IRG MI		2,542			
36	01STDAY041 - Daily Standard Offer	47	985			0.0210
37	01USBGV033-KLAMATH IRG TOU		-31			
38	01USBOF033-KLAMATH BASIN	44,836	1,225,153	652	68,767	0.0273
39	01USBON033-KLAMATH BASIN		-125,299			
40	01USBON033-KLAMATH BASIN	52,490	1,296,725	1,397	37,573	0.0247
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	01USBON033-KLAMATH BASIN		-145,198			
2	01USBGV033-IRG TOU W/O BPA	2,964	51,910	10	296,400	0.0175
3	IRRIGATION BPA BAL ACCT		-7,116			
4	IRRIGATION UNBILLED	76	5,000			0.0658
5	01LNX00312 - OR IRG LINE EXT		9,315			
6	01NMT33135 - OR NET MTR -			1		
7	01NMT41135 - NETMTR AG PMP			1		
8	01ZZMERGCR-MERGER CREDITS		5			
9	OR GAIN ON SALE OF ASSET		22,685			
10	OR Irrigation - BPA adjustment		17,167			
11	OR SB408 RECOVERY		218,391			
12	OR SB 838 RECOVERY		-199,960			
13	UTAH					
14	08APSV0010-IRR & SOIL DRA	185,190	10,874,683	2,618	70,737	0.0587
15	08APSV10NS- Irg Soil Drain Pump N	14,842	832,491	88	168,659	0.0561
16	08LNX00002-MTHLY 80% GUAR		985			
17	08LNX00004-ANNUAL 80%GUAR		26,710			
18	08LNX00014-80% MIN MNTHLY		1,811			
19	08LNX00017-ADV/REF&80%ANN		181,918			
20	08LNX00300 - LINE EXT 80% PLUS		-255			
21	08LNX00310 - IRR, 80% ANNUAL		6,823			
22	08LNX00312 UT IRG LINE EXT		4,208			
23	08NMT10135-UT IRR_SOIL DRNG	19	1,420	1	19,000	0.0747
24	UNBILLED REV - IRRIGATION	225	14,000			0.0622
25	WASHINGTON					
26	02APSV0040-WA AG PMP SRVC	144,135	9,711,488	4,615	31,232	0.0674
27	02APSV0040-WA AG PMP SRVC		-384,070			
28	02APSV040X-WA AG PMP SRVC	24,724	1,655,638	698	35,421	0.0670
29	02BPADEBIT-BPA ADJUST FEE		9,693			
30	02LNX00102-LINE EXT 80% G		878			
31	02LNX00103-LINE EXT 80% G		10,482			
32	02LNX00105-CNTRCT $ MIN G		30			
33	02LNX00109-REF/NREF ADV +		39			
34	02LNX00110-REF/NREF ADV +		100,557			
35	02LNX00310 - IRG, 80% ANNUAL		1,703			
36	02LNX00312 - WA IRG LINE EXT		7,011			
37	02ZZMERGCR-MERGER CREDITS		3			
38	WASHINGTON - CHEHALIS		720,000			
39	IRRIGATION BPA BAL ACCT		-162,641			
40	IRRIGATION UNBILLED	57	3,000			0.0526
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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1	WYOMING					
2	05APS00040-AG PUMPING SVC	16,256	1,194,669	606	26,825	0.0735
3	05LNX00110-REF/NREF ADV +		58,635			
4	05LNX00103-LINE EXT 80% G		8,725			
5	05LNX00312 - WY IRG LINE EXT		357			
6	IRRIGATION UNBILLED	17	1,000			0.0588
7	05LNX00110-REF/NREF ADV +		15,544			
8	09APSV0210-IRR & SOIL DRA	3,296	253,719	65	50,708	0.0770
9	LESS MULTIPLE BILLINGS			-674		
10						
11	TOTAL IRRIGATION SALES	1,222,188	85,413,308	23,087	52,938	0.0699
12						
13	PUBLIC STREET&HIGHWAY					
14	CALIFORNIA					
15	06COSL0052-CO-OWND STR LG	8	6,834	5	1,600	0.8543
16	06CUSL053F-SPECIAL CUST O	1,225	155,279	120	10,208	0.1268
17	06CUSL058F-CUST OWND STR	242	34,578	23	10,522	0.1429
18	06HPSV0051-HI PRESSURE SO	681	168,687	73	9,329	0.2477
19	UNBILLED REVENUE	31	6,000			0.1935
20	IDAHO					
21	07GNSV023S-IDAHO TRAFFIC	160	15,572	25	6,400	0.0973
22	07SLCO0011-STR LGT CO-OWN	110	48,239	30	3,667	0.4385
23	07SLCU012E-ENGY STR	123	13,486	9	13,667	0.1096
24	07SLCU012F-FULL MNT STR	1,946	365,705	279	6,975	0.1879
25	07SLCU012P-PART MNT STR LGT	194	26,697	16	12,125	0.1376
26	UNBILLED REVENUE	24	3,000			0.1250
27	OREGON					
28	01COSL0052-STR LGT SRVC C	978	116,267	63	15,524	0.1189
29	01CUSL0053-CUS-OWNED MTRD	809	55,106	69	11,725	0.0681
30	01CUSL053E-STR LGT SVC	8,316	566,525	166	50,096	0.0681
31	01CUSL053F-STR LGT SRVC C	267	27,778	22	12,136	0.1040
32	01HPSV0051-HI PRESSURE SO	17,811	3,402,344	681	26,154	0.1910
33	01MVSL0050-MERC VAPSTR LG	9,949	1,196,804	267	37,262	0.1203
34	01OALT014N-OUTD AR LGT NR	3	616	3	1,000	0.2053
35	01OALT014N-OUTD AR LGT NR		-12			
36	01OALT015N-OUTD AR LGT NR	8	1,065	4	2,000	0.1331
37	BPA BALANCING ACCOUNT		-1			
38	OR GAIN ON SALE OF ASSET		3,739			
39	OR SB408 RECOVERY		33,054			
40	OR SB 838 RECOVERY		-17,255			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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1	UNBILLED REVENUE	464	68,000			0.1466
2	UTAH					
3	08CFR00012-STR LGTS (CONV		54			
4	08CFR00051-MTH FAC SRVCHG		4,529			
5	08CFR00061-U/G AREA LIGHT		85			
6	08CFR00062-STREET LIGHTS		79			
7	08HAXT0060-LIGHTNG-HAXTON		38	1		
8	08OALT007N-SECURITY AR LG	5	1,536	5	1,000	0.3072
9	08TOSS015F-TRAFFIC SIG NM	1,142	83,934	126	9,063	0.0735
10	08SLCO0011-STR LGT CO-OWN	23,085	6,709,431	1,019	22,655	0.2906
11	08TOSS0015-TRAF & OTHER S	2,997	277,747	1,528	1,961	0.0927
12	08MONL0015-MTR OUTDONIGHT	1,057	81,564	54	19,574	0.0772
13	08SLCU012P-STR LGT CUST-O	6,585	815,501	242	27,211	0.1238
14	08SLCU012F-STR LGT CUST-O	3,389	467,142	148	22,899	0.1378
15	08SLD13ES1-DECOR CUST-OWN		-2			
16	08SLCU012E-DECOR CUST-OWN	39,501	2,519,984	410	96,344	0.0638
17	08THIK0077-STR LIGHT SPEC	141	17,277	1	141,000	0.1225
18	UNBILLED REVENUE	323	51,000			0.1579
19	WASHINGTON					
20	02CFR00012-STR LGTS (CONV		91			
21	02COSL0052-WA STR LGT SRV	443	59,009	19	23,316	0.1332
22	02CUSL053F-WA STR LGT SRV	3,675	234,714	107	34,346	0.0639
23	02CUSL053M-WA STR LGT SRV	1,158	73,232	93	12,452	0.0632
24	02HPSV0051-WA HI PRESSURE	3,103	562,958	148	20,966	0.1814
25	02MVSL0057-WA MERC VAPSTR	2,013	225,704	46	43,761	0.1121
26	WASHINGTON - CHEHALIS		180,000			
27	UNBILLED REVENUE	780	90,000			0.1154
28	WYOMING					
29	05COSL0057-CO-OWND STR LG	320	67,201	21	15,238	0.2100
30	05CUSL058F-CUST OWND STR	418	28,309	37	11,297	0.0677
31	05CUSL058M-CUST OWND STR	70	4,611	10	7,000	0.0659
32	05CUSL0E58-WY CUST OWNED	705	45,340	31	22,742	0.0643
33	05CUSL0M58-CUST OWNED	38	2,999	5	7,600	0.0789
34	05HPSV0051-HI PRESSURE SO	4,636	1,009,517	154	30,104	0.2178
35	05OALT015N-OUTD AR LGT SR		3			
36	05MVS00053-MERCURY VAPOR	3,963	515,059	267	14,843	0.1300
37	UNBILLED REVENUE	166	26,000			0.1566
38	09MONL0213-WY MTR OUTDOOR	26	2,257	1	26,000	0.0868
39	09SLCO0211-STR LGT CO-OWN	1,388	386,956	48	28,917	0.2788
40	09SLCU2121-STR LGT CUST-O	35	4,324	10	3,500	0.1235
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
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1	09SLCU2122-TRAF & OTHER S	24	1,255	14	1,714	0.0523
2	09SLCU2123-MTR OUTDONIGHT	4	278	1	4,000	0.0695
3	09SLCUP212-CUST OWNED	46	7,847	9	5,111	0.1706
4	09TOSS0213-WY TRAF & OTHER	39	1,728	13	3,000	0.0443
5	UNBILLED REVENUE	141	56,000			0.3972
6	LESS MULTIPLE BILLINGS			-2,475		
7						
8	TOTAL PUBLIC STREET &	144,765	20,913,398	3,948	36,668	0.1445
9						
10	OTHER SALES TO PUBLIC AUTH					
11	UTAH					
12	08GNSV0006-GEN SRVC-DISTR	2,338	155,904	4	584,500	0.0667
13	08GNSV0023-GEN SRVC-DISTR	29	2,785	3	9,667	0.0960
14	08GNSV009M-MANL HIGH VOLT	438,695	18,893,014	4	109,673,750	0.0431
15	08OALT007N-SECURITY AR LG	18	4,445	2	9,000	0.2469
16	UNBILLED REVENUE	-3,485	-24,000			0.0069
17						
18	TOTAL OTHER SALES TO PUBLIC	437,595	19,032,148	13	33,661,154	0.0435
19						
20	FORFEITED DISCOUNTS					
21	CALIFORNIA					
22	Late Fees		267,617			
23	IDAHO					
24	Late Fees		411,562			
25	OREGON					
26	Late Fees		2,566,024			
27	UTAH					
28	Late Fees		2,947,238			
29	WASHINGTON					
30	Late Fees		556,652			
31	WYOMING					
32	Late Fees		569,275			
33						
34	TOTAL FORFEITED DISCOUNTS		7,318,368			
35						
36	MISCELLANEOUS SERVICE REV					
37	CALIFORNIA					
38	06CFR00003-MTH MAINTENANC		1,454			
39	06CONN0300-CA RECONNECTIO		115,750			
40	06FCBUYOUT		196,359			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
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1	06RCHK0300-CA RET CHK CHR		15,276			
2	06TAMP0300-CA TAMP & UNAU		2,625			
3	06TEMP0300-CA TEMP SRVC C		2,665			
4	06TRBL0300-CA TROUBLE CAL		90			
5	06XMTRTAMP-TAMPERING -		521			
6	Home Comfort		1,224			
7	Other		2,679			
8	IDAHO					
9	07CFR00001-MTH FAC SRVCHG		2,056			
10	07CONN0300-ID RECONNECTIO		114,605			
11	07FCBUYOUT - FAC CHG BUYOUT		1,723			
12	07RCHK0300-ID RET CHK CHR		37,080			
13	07TAMP0300		1,575			
14	07TEMP0014-TEMP SRVC CONN		10,315			
15	07XMTRTAMP-TAMPERING -		97			
16	Weatherization Loans ID		629			
17	Other		-4			
18	OREGON					
19	01CFR00001-MTH FACILITY S		61,966			
20	01CFR00003-MTH MAINTENANC		26,039			
21	01CFR00004-EMRGNCY ST&BY		25,056			
22	01CFR00005-INTERMTNT		42,230			
23	01CFR00013-MTH MISC CHRG		2,284			
24	01CFR00014-YR MISC CHRG		5			
25	01CONN0300-RECONNECTION C		628,510			
26	01DPAC0300-DEMAND PULSE		3,000			
27	01ESSC0600 - ESS charges		7,150			
28	01FCBUYOUT-FAC CHG BUYOUT		395,537			
29	01RCHK0300-RETURNED CHECK		300,800			
30	01TAMP0300-TAMP & UNAUTH		11,850			
31	01TEMP0300-TEMP SRVC CHRG		79,065			
32	01TRBL0300-TROUBLE CALL C		40			
33	01XMTRTAMP-TAMPERING -		6,532			
34	Other		2,959			
35	UTAH					
36	08CFR00013-MTH MISC CHRG		147,885			
37	08CFR00051-MTH FAC SRVCHG		74,695			
38	08CFR00052-ANN FAC SVCCHG		424			
39	08CFR00053-MTHLY MAINTFEE		10,575			
40	08CFR00063-MTH MISC CHARG		3,301			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/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.
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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	08CFR00064-ANN MISC CHARG		6,660			
2	08CONN0300-RECONN&DISCONN		254,970			
3	08CONTSERV-3RD PARTY O/S		292,533			
4	08FCBUYOUT-FAC CHG BUYOUT		518,434			
5	08NCON0300-UT FEE NRES RE		6,455			
6	08RCHK0300-UT RET CHK CHR		458,280			
7	08RCON0001-CONNECT FEE		1,534,970			
8	08TAMP0300-TAMPERING&UNAU		16,950			
9	08TEMP0014-TEMP SRVC CONN		284,670			
10	08XMTRTAMP-TAMPERING -		12,482			
11	Energy Finanswer 12,000		942			
12	Energy Finanswer new Com		36,875			
13	Other		23,275			
14	08GNSV0009-GEN SRVC-HI VO		-3,654			
15	08VISIT300 - UT Visit, Service Ca		279,910			
16	WASHINGTON					
17	02CFR00003-MTH MAINTENANC		1,320			
18	02CFR00004-EMRGNCY ST&BY		5,900			
19	02CFR00005-INTERMTNT SRVC		4,313			
20	02CONN0300-WA RECONNECTIO		124,085			
21	02FCBUYOUT - FAC CHG BUYOUT		5,163			
22	02RCHK0300-WA RET CHK CHR		62,360			
23	02TAMP0300-WA TAMP & UNAU		5,775			
24	02TEMP0300-WA TEMP SRVC C		20,045			
25	02XMTRTAMP-TAMPERING -		1,857			
26	Energy Finanswer new Com		4,084			
27	Home Comfort		4,701			
28	Other		-19,420			
29	WYOMING					
30	05CFR00003-MTH MAINTENANC		8,032			
31	05CFR00004-EMRGNCY ST&BY		19,472			
32	05CFR00005-INTERMTNT SRVC		10,607			
33	05CFR00013-MTH MISC CHRG		3,186			
34	05CONN0300-WY RECONNECTIO		131,330			
35	05FCBUYOUT - FAC CHG BUYOUT		111,601			
36	05LONGFORM-BILL PRINT		80			
37	05RCHK0300-WY RET CHK CHR		68,490			
38	05TAMP0300		1,650			
39	05TEMP0300-WY TEMP SRVC C		28,875			
40	Other		-7,237			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	05XMTRTAMP-TAMPERING -		201			
2	09CFR00005-INTERMTNT SRVC		339			
3	05CONN0300-WY RECONNECTIO		27,760			
4	05FCBUYOUT - FAC CHG BUYOUT		206,838			
5	05RCHK0300-WY RET CHK CHR		11,190			
6	05SERV0300-WY SRVC CALLS		120			
7	05TAMP0300		150			
8	05TEMP0300-WY TEMP SRVC C		1,700			
9	09CFR00001-MTH FAC SRVCHG		5,393			
10	09CFR00014-YR MISC CHRG		3			
11	Energy Finanswer 12,000		425			
12	Other		-1,869			
13						
14	TOTAL MISC SERVICE REV		6,908,893			
15						
16	SALES OF WATER AND WTR PWR					
17	UTAH		3,254			
18	WYOMING		8,900			
19	TOTAL WATER AND WATER PWR		12,154			
20						
21	RENT FROM ELEC PROPERTIES					
22	CALIFORNIA					
23	06CFR00006-MTH RNTAL CHRG		1,710			
24	RENT REV-TRANSMISS		55			
25	Rent Revenue - Subleases		17,123			
26	Joint use		545,902			
27	IDAHO					
28	07CFR00009-YR LSE CHRG-EQ		789			
29	07INVCHG00-INVEST MNT CHG		180			
30	07LOOP0014-MTH FEE PRE-AS		-2,870			
31	07POLE0075-STEEL POLES US		281			
32	07XTRN0013-RNT/LSE L& PRO		103,108			
33	RENT REVENUE-HYDRO		13,750			
34	Rent Revenue - Subleases		2,216			
35	Joint use		198,816			
36	OREGON					
37	01CFR00006-MTH RNTAL CHRG		519,151			
38	RENTS - COMMON		432,563			
39	Rents - Non Common		25			
40	MCI FOGWIRE REVENUE		3,347,013			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Rent Revenue - Subleases		333,190			
2	RENT REVENUE-HYDRO		28,543			
3	RENT REV-TRANSMISS		224,663			
4	RENT REV-DISTRIBUT		35,364			
5	RENT REV-GEN(COMM)		61,259			
6	Joint use		4,382,214			
7	UTAH					
8	08CFR00056-MTH EQUIP RENT		33			
9	08CFR00058-MTH EQUIP LEAS		709,502			
10	08INVCHG0N-INVEST MNT CHG		4,682			
11	08INVCHG0R-INVEST MNT CHG		301			
12	08LOOP014N-TEMP SERV CONN		-4,067			
13	08POLE0004-POLE ATTACHMEN		2,004			
14	08POLE0075-STEEL POLES US		64,248			
15	08XTRN0013-RNT/LSE L& PRO		75,184			
16	RENTS - COMMON		-19,690			
17	Rents - Non Common		12,288			
18	RENT REVENUE-STEAM		94,943			
19	RENT REVENUE-HYDRO		134,964			
20	RENT REV-TRANSMISS		746,163			
21	RENT REV-DISTRIBUT		484,488			
22	RENT REV-GEN(COMM)		8,607			
23	Rent Revenue - Subleases		2,441,325			
24	Joint use		1,971,364			
25	WASHINGTON					
26	02CFR00001-MTH FACILITY S		2,104			
27	02CFR00006-MTH RNTAL CHRG		-14,415			
28	RENT REVENUE-HYDRO		633,841			
29	RENT REV-DISTRIBUT		15,624			
30	RENT REV-GEN(COMM)		37,032			
31	RENT REV-TRANSMISS		7,263			
32	Rent Revenue - Subleases		44,159			
33	Joint use		987,309			
34	WYOMING					
35	05CFR00001-MTH FACILITY S		11,438			
36	05CFR00006-MTH RNTAL CHRG		2,521			
37	RENT REVENUE-STEAM		41,068			
38	RENT REVENUE-HYDRO		14,644			
39	RENT REV-TRANSMISS		850			
40	RENT REV-DISTRIBUT		7,513			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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SALES OF ELECTRICITY BY RATE SCHEDULES

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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	Rent Revenue - Subleases		18,070			
2	Joint use		347,572			
3	09LOOP0214-MTH FEE PRE-AS		180			
4	09POLE0075-STEEL POLES US		20,128			
5	RENT REVENUE-STEAM		5,453			
6	Joint Use		5,193			
7						
8	TOTAL RENT FROM ELEC PROP		19,158,931			
9						
10	OTHER ELEC ESTIMATE		-375,040			
11	RENEWABLE ENERGY CREDIT		50,793,765			
12	NON-WHEELING SYSTEM		9,622,751			
13	Other Elec (exclud Wheel)		7,262,676			
14	CALIFORNIA					
15	DSM REV-CA SBC OFF		-1,097,786			
16	Fish, Wildlife, Recr		6,669			
17	IDAHO					
18	DSM REV-ID SBC		5,010,486			
19	Other Elec (exclud Wheel)		123			
20	OREGON					
21	3RD PARTY TRANS		423,133			
22	DSM REVENUE - OREGON ECC		8,579,678			
23	Other Elec (exclud Wheel)		2,248,385			
24	Other Elec DSR carry chrg		317,738			
25	01XTRN0011-SALE ORDERS (I		3,775			
26	UTAH					
27	ELEC INC-OTHR		81,577			
28	FLYASH SALES		2,198,373			
29	DSM REV-UT SBC OFFSET		36,046,587			
30	Fish, Wildlife, Recr		2,280			
31	08XTRN0011-SALE ORDERS (I		21,288			
32	M&S INVENTORY REVENUE		965,154			
33	WASHINGTON					
34	Fish, Wildlife, Recr		3,356			
35	Wash Colstrip 3		-52,188			
36	WYOMING					
37	FLYASH SALES		1,020,891			
38	WY Regulatory Recovery Fee		200,015			
39	DSM REVENUE - WY SBC - CAT 1		468,221			
40	DSM REVENUE - WY SBC - CAT 2		230,731			
41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

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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	DSM REVENUE - WY SBC - CAT 3		97,384			
2	Other Elec (exclud Wheel)		-2			
3	FLYASH SALES		19,604			
4	DSM REVENUE - WY SBC - CAT 1		214,311			
5	DSM REVENUE - WY SBC - CAT 2		125,656			
6	DSM REVENUE - WY SBC - CAT 3		266,792			
7	05XTRN0011 - SALES ORDERS INV		825			
8	TOTAL OTHER ELEC REVENUE		124,707,208			
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41	TOTAL Billed	52,769,514	3,639,426,120	1,718,485	30,707	0.0690
42	Total Unbilled Rev.(See Instr. 6)	-59,989	3,093,000	0	0	-0.0516
43	TOTAL	52,709,525	3,642,519,120	1,718,485	30,672	0.0691

Schedule Page: 304 Line No.: 41 Column: b

The following table is a reconciliation of the billed and unbilled MWh for the year 2009.

	MWh
Total billed in 2009	52,769,514
12/31/2008 unbilled MWh reversal	(3,440,267)
Total MWh earned and billed in 2009	49,329,247
12/31/2009 unbilled MWh accrual	3,380,278
Total MWh (unbilled and billed) in 2009	52,709,525

Schedule Page: 304 Line No.: 41 Column: c

The following table is a reconciliation of the billed and unbilled revenue for the year 2009.

	Revenue
Total billed in 2009	$ 3,639,426,120
12/31/2008 unbilled revenue reversal	(210,896,000)
Total revenue earned and billed in 2009	3,428,530,120
12/31/2009 unbilled revenue accrual	213,989,000
Total revenue (unbilled and billed) in 2009	$ 3,642,519,120

Schedule Page: 304 Line No.: 42 Column: c

For further discussion on unbilled revenue refer to page 300, Electric Operating Revenues, line 12, column (b).

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Requirement Sales					
2	Brigham City	RQ	T-12	19	18	17
3	Deaver, Town of	RQ	T-4	0.2	0.1	0.1
4	Helper City	RQ	T-6	1	1	0.9
5	Helper City Annex	RQ	T-6	0.7	0.6	0.6
6	Navajo Tribal Util Auth (Mexican Hat)	RQ	T-6	0.2	0.2	0.2
7	Navajo Tribal Util Auth (Red Mesa)	RQ	T-6	1	1	1
8	Portland General Electric Company	RQ	147	NA	NA	NA
9	Price City	RQ	T-12	13	12	11
10	Accrual True-up	RQ	NA	NA	NA	NA
11						
12	Nonrequirement Sales					
13	Anaheim, City of	SF	WSPP	NA	NA	NA
14	Arizona Public Service Company	AD	T-12	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
					1
101,762	1,833,836	2,102,756		3,936,592	2
1,038	15,767	18,640		34,407	3
7,973	115,285	110,781	62,130	288,196	4
3,702	72,092	65,508		137,600	5
1,165	20,762	20,292		41,054	6
8,181	126,713	142,507		269,220	7
11,327		1,003,932	9,426	1,013,358	8
73,238	1,233,188	1,499,326		2,732,514	9
-2,778			-100,300	-100,300	10
					11
					12
2,400		75,560		75,560	13
190			17,980	17,980	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Arizona Public Service Company	SF	T-12	NA	NA	NA
2	Avista Corporation	SF	T-13	NA	NA	NA
3	Avista Corporation	SF	WSPP	NA	NA	NA
4	BP Energy Company	AD	WSPP	NA	NA	NA
5	BP Energy Company	SF	WSPP	NA	NA	NA
6	Barclays Bank PLC	AD	T-12	NA	NA	NA
7	Barclays Bank PLC	SF	T-12	NA	NA	NA
8	Basin Electric Power Cooperative	LF	T-11	NA	NA	NA
9	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
10	Basin Electric Power Cooperative	SF	WSPP	NA	NA	NA
11	Black Hills Power, Inc.	LF	441	50	50	41
12	Black Hills Power, Inc.	OS	WSPP	NA	NA	NA
13	Black Hills Power, Inc.	SF	WSPP	NA	NA	NA
14	Bonneville Power Administration	AD	T-13	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	04/14/2010	End of 2009/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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
93,193		2,590,803		2,590,803	1
69			2,120	2,120	2
74,299		2,353,049		2,353,049	3
440			17,932	17,932	4
225,424		11,817,291		11,817,291	5
467			39,550	39,550	6
1,471,517		94,724,053		94,724,053	7
816			28,663	28,663	8
1,178			31,427	31,427	9
33,415		1,222,031		1,222,031	10
358,074	6,212,723	5,652,158		11,864,881	11
19,298		593,945		593,945	12
36,447		1,548,181		1,548,181	13
			-8	-8	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Bonneville Power Administration	LF	368	NA	NA	NA
2	Bonneville Power Administration	LF	T-11	NA	NA	NA
3	Bonneville Power Administration	LU	T-12	NA	NA	NA
4	Bonneville Power Administration	SF	T-13	NA	NA	NA
5	Bonneville Power Administration	SF	WSPP	NA	NA	NA
6	British Columbia Transmission Corp.	SF	T-13	NA	NA	NA
7	Burbank, City of	SF	WSPP	NA	NA	NA
8	California Independent System Operator	AD	T-12	NA	NA	NA
9	California Independent System Operator	SF	T-12	NA	NA	NA
10	Cargill Power Markets, LLC	AD	T-12	NA	NA	NA
11	Cargill Power Markets, LLC	OS	T-12	NA	NA	NA
12	Cargill Power Markets, LLC	SF	T-11	NA	NA	NA
13	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
14	Chelan County PUD #1	SF	T-13	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
2,030			62,677	62,677	1
3,109			98,345	98,345	2
32,961		2,068,632		2,068,632	3
73			1,896	1,896	4
150,204		5,047,995		5,047,995	5
47			1,043	1,043	6
17,248		556,250		556,250	7
720			-526,130	-526,130	8
491,019		14,587,376		14,587,376	9
801			42,393	42,393	10
50		3,900		3,900	11
9,126			245,134	245,134	12
1,466,084		49,668,637	1,000	49,669,637	13
2			55	55	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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:
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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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	Citigroup Energy, Inc.	AD	T-12	NA	NA	NA
2	Citigroup Energy, Inc.	SF	T-11	NA	NA	NA
3	Citigroup Energy, Inc.	SF	T-12	NA	NA	NA
4	Clatskanie People's Utility District	SF	WSPP	NA	NA	NA
5	Colorado River Commission of Nevada	SF	WSPP	NA	NA	NA
6	Colorado Springs Utilities	SF	WSPP	NA	NA	NA
7	Conoco Inc.	SF	T-12	NA	NA	NA
8	Constellation Energy Commodities Group	AD	T-12	NA	NA	NA
9	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
10	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
11	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
12	Credit Suisse Energy LLC	AD	T-12	NA	NA	NA
13	Credit Suisse Energy LLC	SF	T-12	NA	NA	NA
14	DB Energy Trading LLC	AD	T-12	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,line 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.
157			9,598	9,598	1
7			185	185	2
1,047,752		70,879,167		70,879,167	3
2,191		66,862		66,862	4
48,800		1,493,280		1,493,280	5
492		22,611		22,611	6
188,160		6,517,979		6,517,979	7
223			12,341	12,341	8
3,678			128,378	128,378	9
77			2,840	2,840	10
461,195		15,969,630		15,969,630	11
985			72,575	72,575	12
972,715		64,525,611		64,525,611	13
6			255	255	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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:
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SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	DB Energy Trading LLC	SF	T-12	NA	NA	NA
2	Douglas County PUD #1	SF	WSPP	NA	NA	NA
3	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
4	El Paso Electric Company	AD	WSPP	NA	NA	NA
5	El Paso Electric Company	SF	WSPP	NA	NA	NA
6	Endure Energy, LLC	SF	T-11	NA	NA	NA
7	Endure Energy, LLC	SF	WSPP	NA	NA	NA
8	Eugene Water & Electric Board	SF	T-11	NA	NA	NA
9	Eugene Water & Electric Board	SF	WSPP	NA	NA	NA
10	Gila River Power, L.P.	SF	T-11	NA	NA	NA
11	Gila River Power, L.P.	SF	WSPP	NA	NA	NA
12	Glendale, City of	SF	WSPP	NA	NA	NA
13	Grant County PUD #2	SF	T-13	NA	NA	NA
14	Grant County PUD #2	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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
160,598		5,241,436		5,241,436	1
80		2,560		2,560	2
301,590		11,056,072		11,056,072	3
16			608	608	4
31,962		1,149,178		1,149,178	5
56			1,807	1,807	6
21,181		599,242		599,242	7
271			10,767	10,767	8
8,300		284,785		284,785	9
17			585	585	10
24,941		762,659		762,659	11
35		1,750		1,750	12
36			1,184	1,184	13
17,467		564,165		564,165	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Hurricane, City of	LF	T-12	NA	NA	NA
2	Iberdrola Renewables, Inc.	LF	T-11	NA	NA	NA
3	Iberdrola Renewables, Inc.	SF	T-11	NA	NA	NA
4	Iberdrola Renewables, Inc.	SF	T-12	NA	NA	NA
5	Idaho Power Company	AD	WSPP	NA	NA	NA
6	Idaho Power Company	LF	T-11	NA	NA	NA
7	Idaho Power Company	SF	T-11	NA	NA	NA
8	Idaho Power Company	SF	T-13	NA	NA	NA
9	Idaho Power Company	SF	WSPP	NA	NA	NA
10	Integrys Energy Services, Inc.	SF	T-11	NA	NA	NA
11	Integrys Energy Services, Inc.	SF	WSPP	NA	NA	NA
12	Intermountain Renewable Power, LLC	LF	T-11	NA	NA	NA
13	Intermountain Renewable Power, LLC	LF	T-11	NA	NA	NA
14	J. Aron & Company	AD	T-12	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
186		13,950		13,950	1
33			1,105	1,105	2
9,660			308,907	308,907	3
565,093		18,828,432		18,828,432	4
9			414	414	5
688			20,686	20,686	6
1,772			48,431	48,431	7
485			17,455	17,455	8
36,770		1,255,554		1,255,554	9
8			305	305	10
2,000		78,900		78,900	11
219			5,059	5,059	12
926			34,053	34,053	13
80			9,452	9,452	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	J. Aron & Company	SF	T-12	NA	NA	NA
2	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
3	J.P. Morgan Ventures Energy Corporation	SF	T-12	NA	NA	NA
4	Los Angeles Dept. of Water & Power	LU	301	NA	NA	NA
5	Los Angeles Dept. of Water & Power	SF	WSPP	NA	NA	NA
6	Macquarie Cook Power Inc.	SF	T-11	NA	NA	NA
7	Macquarie Cook Power Inc.	SF	WSPP	NA	NA	NA
8	Metropolitan Water District of S. Cal.	SF	WSPP	NA	NA	NA
9	Modesto Irrigation District	SF	WSPP	NA	NA	NA
10	Morgan Stanley Capital Group, Inc.	AD	T-12	NA	NA	NA
11	Morgan Stanley Capital Group, Inc.	SF	T-11	NA	NA	NA
12	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
13	Municipal Energy Agency of Nebraska	SF	WSPP	NA	NA	NA
14	Nevada Power Company	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
207,579		10,828,769		10,828,769	1
2			71	71	2
315,370		11,468,024		11,468,024	3
577,331		25,739,038		25,739,038	4
295,242		9,891,247		9,891,247	5
			20	20	6
137,732		4,366,479		4,366,479	7
3,400		77,750		77,750	8
63,722		2,319,751		2,319,751	9
3,628			169,184	169,184	10
5,649			187,308	187,308	11
2,209,690		128,070,164	65,880	128,136,044	12
9,652		322,522		322,522	13
60,000		2,641,160		2,641,160	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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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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	NextEra Energy Power Marketing, LLC	LF	T-11	NA	NA	NA
2	NextEra Energy Power Marketing, LLC	SF	WSPP	NA	NA	NA
3	NorthWestern Energy	SF	T-13	NA	NA	NA
4	NorthWestern Energy	SF	WSPP	NA	NA	NA
5	Northern California Power Agency	SF	WSPP	NA	NA	NA
6	Northpoint Energy Solutions Inc.	SF	WSPP	NA	NA	NA
7	PPL EnergyPlus, LLC	SF	WSPP	NA	NA	NA
8	PPL Montana, LLC	SF	T-11	NA	NA	NA
9	Pacific Gas & Electric Company	SF	T-11	NA	NA	NA
10	Pacific Gas & Electric Company	SF	WSPP	NA	NA	NA
11	Pacific Northwest Generating Coop	SF	WSPP	NA	NA	NA
12	Pacific Summit Energy LLC	AD	T-12	NA	NA	NA
13	Pacific Summit Energy LLC	SF	T-12	NA	NA	NA
14	Portland General Electric Company	AD	T-12	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.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
288			12,164	12,164	1
76,055		2,905,590		2,905,590	2
167			5,123	5,123	3
1,647		65,530		65,530	4
5,261		198,723		198,723	5
28,638		1,023,674		1,023,674	6
83,389		2,575,245		2,575,245	7
453			15,794	15,794	8
6			208	208	9
238,823		10,316,353		10,316,353	10
2,325		68,050		68,050	11
18			983	983	12
94,525		4,064,323		4,064,323	13
11			363	363	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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.
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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	Portland General Electric Company	SF	T-11	NA	NA	NA
2	Portland General Electric Company	SF	T-12	NA	NA	NA
3	Portland General Electric Company	SF	T-13	NA	NA	NA
4	Powerex Corporation	AD	WSPP	NA	NA	NA
5	Powerex Corporation	LF	T-11	NA	NA	NA
6	Powerex Corporation	SF	T-11	NA	NA	NA
7	Powerex Corporation	SF	WSPP	NA	NA	NA
8	Public Service Company of Colorado	AD	320	NA	NA	NA
9	Public Service Company of Colorado	AD	WSPP	NA	NA	NA
10	Public Service Company of Colorado	LF	320	107	101	84
11	Public Service Company of Colorado	SF	T-11	NA	NA	NA
12	Public Service Company of Colorado	SF	WSPP	NA	NA	NA
13	Public Service Company of New Mexico	OS	WSPP	NA	NA	NA
14	Public Service Company of New Mexico	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	04/14/2010	End of 2009/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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
19			783	783	1
153,727		6,499,591		6,499,591	2
125			4,811	4,811	3
190			17,445	17,445	4
17,339			527,349	527,349	5
12,345			378,505	378,505	6
911,432		25,956,721		25,956,721	7
			-1,471,182	-1,471,182	8
1,462			79,952	79,952	9
700,179	14,367,960	34,658,860		49,026,820	10
1,522			34,234	34,234	11
91,502		2,707,206		2,707,206	12
			3,000	3,000	13
118,977		3,880,082		3,880,082	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
2	Puget Sound Energy, Inc.	SF	WSPP	NA	NA	NA
3	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
4	Rainbow Energy Marketing Corporation	SF	WSPP	NA	NA	NA
5	Raser Power Systems, LLC	SF	T-11	NA	NA	NA
6	Redding, City of	SF	WSPP	NA	NA	NA
7	Riverside, City of	SF	WSPP	NA	NA	NA
8	Sacramento Municipal Utility District	AD	250	NA	NA	NA
9	Sacramento Municipal Utility District	AD	WSPP	NA	NA	NA
10	Sacramento Municipal Utility District	LF	250	NA	NA	NA
11	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
12	Sacramento Municipal Utility District	SF	WSPP	NA	NA	NA
13	Salt River Project	AD	WSPP	NA	NA	NA
14	Salt River Project	IF	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 ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
32			1,119	1,119	1
185,580		5,754,449		5,754,449	2
2,421			73,600	73,600	3
84,210		2,606,038		2,606,038	4
35			761	761	5
3,361		119,056		119,056	6
1,440		56,160		56,160	7
-1,208			258,776	258,776	8
1,208			71,816	71,816	9
564,109		12,833,480		12,833,480	10
5			214	214	11
162,447		5,764,953		5,764,953	12
63			1,641	1,641	13
219,000		6,690,484		6,690,484	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Salt River Project	SF	T-11	NA	NA	NA
2	Salt River Project	SF	WSPP	NA	NA	NA
3	San Diego Gas & Electric Company	SF	WSPP	NA	NA	NA
4	Santa Clara, City of	SF	WSPP	NA	NA	NA
5	Seattle City Light	LF	T-11	NA	NA	NA
6	Seattle City Light	SF	T-13	NA	NA	NA
7	Seattle City Light	SF	WSPP	NA	NA	NA
8	Sempra Energy Solutions, LLC	SF	WSPP	NA	NA	NA
9	Sempra Energy Trading LLC	AD	T-12	NA	NA	NA
10	Sempra Energy Trading LLC	SF	T-12	NA	NA	NA
11	Sempra Generation	SF	T-12	NA	NA	NA
12	Shell Energy North America (US), L.P.	AD	WSPP	NA	NA	NA
13	Shell Energy North America (US), L.P.	SF	T-11	NA	NA	NA
14	Shell Energy North America (US), L.P.	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
695			15,302	15,302	1
48,303		1,345,628		1,345,628	2
454,678		16,217,612		16,217,612	3
2,685		82,525		82,525	4
281			9,306	9,306	5
9			311	311	6
35,735		1,003,545		1,003,545	7
5,864		157,656		157,656	8
24			2,003	2,003	9
1,372,078		74,249,459		74,249,459	10
2,240		61,900		61,900	11
100			4,200	4,200	12
198			7,063	7,063	13
1,101,172		52,884,326		52,884,326	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Sierra Pacific Power Company	AD	258	NA	NA	NA
2	Sierra Pacific Power Company	LF	258	75	75	75
3	Sierra Pacific Power Company	LF	T-11	NA	NA	NA
4	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
5	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
6	Snohomish Public Utility District No. 1	SF	WSPP	NA	NA	NA
7	Southern California Edison Company	SF	T-12	NA	NA	NA
8	Southwestern Public Service Company	SF	WSPP	NA	NA	NA
9	State of California Department of Water	SF	WSPP	NA	NA	NA
10	Tacoma, City of	SF	WSPP	NA	NA	NA
11	The Energy Authority	SF	T-11	NA	NA	NA
12	The Energy Authority	SF	WSPP	NA	NA	NA
13	TransAlta Energy Marketing Inc.	AD	T-12	NA	NA	NA
14	TransAlta Energy Marketing Inc.	IF	T-12	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
			-194,965	-194,965	1
74,340	2,521,500	3,065,782		5,587,282	2
884			27,375	27,375	3
246			10,797	10,797	4
344			12,396	12,396	5
53,805		2,976,238		2,976,238	6
129,029		4,609,129		4,609,129	7
7,250		219,500		219,500	8
600		27,092		27,092	9
2,100		61,375		61,375	10
			18	18	11
22,965		734,520		734,520	12
11			1,183	1,183	13
1,315,190		48,195,982		48,195,982	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	TransAlta Energy Marketing Inc.	SF	T-11	NA	NA	NA
2	TransAlta Energy Marketing Inc.	SF	T-12	NA	NA	NA
3	TransCanada Energy Sales Ltd.	SF	WSPP	NA	NA	NA
4	Tri-State Generation & Transmission	SF	T-11	NA	NA	NA
5	Tri-State Generation & Transmission	SF	WSPP	0.7	0.7	0.1
6	Tucson Electric Power Company	SF	WSPP	NA	NA	NA
7	Turlock Irrigation District	SF	T-13	NA	NA	NA
8	Turlock Irrigation District	SF	WSPP	NA	NA	NA
9	UBS Warburg Energy LLC	AD	T-12	NA	NA	NA
10	UBS Warburg Energy LLC	SF	T-12	NA	NA	NA
11	UNS Electric, Inc.	SF	WSPP	NA	NA	NA
12	Utah Associated Municipal Power Systems	OS	WSPP	NA	NA	NA
13	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
14	Utah Associated Municipal Power Systems	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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
440			15,075	15,075	1
271,045		8,605,025	6,763	8,611,788	2
1,960		88,800		88,800	3
639			17,068	17,068	4
121,877	32,468	4,088,869		4,121,337	5
196,173		6,022,201		6,022,201	6
1			33	33	7
28,540		933,695		933,695	8
15			820	820	9
138,575		9,796,612		9,796,612	10
156,825		4,194,337		4,194,337	11
15,994		639,760		639,760	12
4			142	142	13
1,170		41,345		41,345	14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	Utah Municipal Power Agency	LF	433	34	34	34
2	Utah Municipal Power Agency	SF	T-3	NA	NA	NA
3	Western Area Power Administration	SF	T-11	NA	NA	NA
4	Western Area Power Administration	SF	WSPP	NA	NA	NA
5	Test Generation	AD	NA	NA	NA	NA
6	Bookout Sales	AD	NA	NA	NA	NA
7	Trade Sales	AD	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
204,722	4,396,200	4,757,739		9,153,939	1
16,035		532,769		532,769	2
2,722			89,496	89,496	3
129,142		4,375,853		4,375,853	4
-8,553			-212,166	-212,166	5
-9,811,672			-314,938,843	-314,938,843	6
			-45,464,949	-45,464,949	7
-6,770			575,818	575,818	8
					9
					10
					11
					12
					13
					14
205,608	3,417,643	4,963,742	-28,744	8,352,641	
12,143,453	27,530,851	966,262,430	-358,824,765	634,968,516	
12,349,061	**30,948,494**	**971,226,172**	**-358,853,509**	**643,321,157**	

FOOTNOTE DATA

Schedule Page: 310 Line No.: 4 Column: j

Settlement Adjustment.

Schedule Page: 310 Line No.: 6 Column: a

Complete name is Navajo Tribal Utility Authority (Mexican Hat).

Schedule Page: 310 Line No.: 7 Column: a

Complete name is Navajo Tribal Utility Authority (Red Mesa).

Schedule Page: 310 Line No.: 8 Column: j

Settlement Adjustment.

Schedule Page: 310 Line No.: 10 Column: j

Represents the difference between actual requirement sales revenues for the period as reflected on the individual line items within this schedule, and the accruals charged to account 447 during the period.

Schedule Page: 310 Line No.: 14 Column: b

Settlement Adjustment.

Schedule Page: 310 Line No.: 14 Column: j

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 2 Column: j

Reserve Share.

Schedule Page: 310.1 Line No.: 4 Column: b

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 4 Column: j

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 6 Column: j

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 8 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.: 8 Column: j

Transmission Losses.

Schedule Page: 310.1 Line No.: 9 Column: j

Transmission Losses.

Schedule Page: 310.1 Line No.: 11 Column: b

Black Hills Power & Light Company - FERC 441 - Contract termination date: December 31, 2023.

Schedule Page: 310.1 Line No.: 12 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 14 Column: b

Settlement Adjustment.

Schedule Page: 310.1 Line No.: 14 Column: j

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 1 Column: b

Bonneville Power Administration - FERC 368 [Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with BPA] - Contract termination date: Upon mutual agreement.

Schedule Page: 310.2 Line No.: 1 Column: j

Transmission Losses.

Schedule Page: 310.2 Line No.: 2 Column: b

Bonneville Power Administration - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179)] - Contract termination date: September 30, 2025.

Schedule Page: 310.2 Line No.: 2 Column: j

Transmission Losses.

Schedule Page: 310.2 Line No.: 3 Column: b

Bonneville Power Administration - FERC T-12 - Contract termination date: April 22, 2024.

Schedule Page: 310.2 Line No.: 4 Column: j

Reserve Share.

Schedule Page: 310.2 Line No.: 6 Column: a

Complete name is British Columbia Transmission Corporation.

Schedule Page: 310.2 Line No.: 6 Column: j

Reserve Share.

Schedule Page: 310.2 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 8 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

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.2 Line No.: 12 Column: j

Transmission Losses.

Schedule Page: 310.2 Line No.: 13 Column: j

Pond Sale.

Schedule Page: 310.2 Line No.: 14 Column: a

Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.2 Line No.: 14 Column: j

Reserve Share.

Schedule Page: 310.3 Line No.: 1 Column: b

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 1 Column: j

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 2 Column: j

Transmission Losses.

Schedule Page: 310.3 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CONSTELLATION ENERGY COMMODITIES GROUP" ON PAGES 310-310.13:

Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 310.3 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 8 Column: j

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 9 Column: j

Transmission Losses.

Schedule Page: 310.3 Line No.: 10 Column: j

Unauthorized use charges.

Schedule Page: 310.3 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 12 Column: j

Settlement Adjustment.

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

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 14 Column: j

Settlement Adjustment.

Schedule Page: 310.4 Line No.: 2 Column: a

Complete name is Public Utility District No. 1 of Douglas County.

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

Settlement Adjustment.

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

Settlement Adjustment.

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

Transmission Losses.

Schedule Page: 310.4 Line No.: 8 Column: j

Transmission Losses.

Schedule Page: 310.4 Line No.: 10 Column: j

Transmission Losses.

Schedule Page: 310.4 Line No.: 13 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "GRANT COUNTY PUD #2" ON PAGES 310-310.13:
Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 310.4 Line No.: 13 Column: j

Reserve Share.

Schedule Page: 310.5 Line No.: 1 Column: b

Hurricane, City of - FERC T-12 - Contract termination date: August 31, 2007.

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

Iberdola Renewables, Inc. - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279)] - Contract termination date: April 30, 2009.

Schedule Page: 310.5 Line No.: 2 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 3 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 5 Column: b

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 5 Column: j

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 6 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, 2012.

Schedule Page: 310.5 Line No.: 6 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 7 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 8 Column: j

Reserve Share.

Schedule Page: 310.5 Line No.: 10 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 12 Column: b

Intermountain Renewable Power, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 509)] - Contract termination date: April 30, 2029.

Schedule Page: 310.5 Line No.: 12 Column: j

Transmission Losses.

Schedule Page: 310.5 Line No.: 13 Column: b

Intermountain Renewable Power, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 509)] - Contract termination date: April 30, 2029.

Schedule Page: 310.5 Line No.: 13 Column: j

Unauthorized use charges.

Schedule Page: 310.5 Line No.: 14 Column: b

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 14 Column: j

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 2 Column: j

Transmission Losses.

Schedule Page: 310.6 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "LOS ANGELES DEPT. OF WATER & POWER" ON PAGES 310-310.13:

Complete name is Los Angeles Department of Water and Power.

Schedule Page: 310.6 Line No.: 4 Column: b

Los Angeles Department of Water and Power - FERC 301 - Contract termination date: June 15, 2027.

Schedule Page: 310.6 Line No.: 6 Column: j

Transmission Losses.

Schedule Page: 310.6 Line No.: 8 Column: a

Complete name is Metropolitan Water District of Southern California.

Schedule Page: 310.6 Line No.: 10 Column: b

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 10 Column: j

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 11 Column: j

Transmission Losses.

Schedule Page: 310.6 Line No.: 12 Column: j

Liquidated Damages.

Schedule Page: 310.7 Line No.: 1 Column: b

NextEra Energy Power Marketing, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 626)] - Contract termination date: December 31, 2011.

Schedule Page: 310.7 Line No.: 1 Column: j

Transmission Losses.

Schedule Page: 310.7 Line No.: 3 Column: j

Reserve Share.

Schedule Page: 310.7 Line No.: 8 Column: j

Transmission Losses.

Schedule Page: 310.7 Line No.: 9 Column: j

Transmission Losses.

Schedule Page: 310.7 Line No.: 11 Column: a

Complete name is Pacific Northwest Generating Cooperative.

Schedule Page: 310.7 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.7 Line No.: 12 Column: j

Settlement Adjustment.

Schedule Page: 310.7 Line No.: 14 Column: b

Settlement Adjustment.

Schedule Page: 310.7 Line No.: 14 Column: j

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 1 Column: j

Transmission Losses.

Schedule Page: 310.8 Line No.: 3 Column: j

Reserve Share.

Schedule Page: 310.8 Line No.: 4 Column: b

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 4 Column: j

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 5 Column: b

PowerEx - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 363)] - Contract termination date: September 30, 2012.

Schedule Page: 310.8 Line No.: 5 Column: j

Transmission Losses.

Schedule Page: 310.8 Line No.: 6 Column: j

Transmission Losses.

Schedule Page: 310.8 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 8 Column: j

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 9 Column: j

Settlement Adjustment.

Schedule Page: 310.8 Line No.: 10 Column: b

Public Service Company of Colorado - FERC 320 - Contract termination date: December 31, 2011.

Schedule Page: 310.8 Line No.: 11 Column: j

Transmission Losses.

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 Reserve.

Schedule Page: 310.9 Line No.: 1 Column: j

Reserve Share.

Schedule Page: 310.9 Line No.: 3 Column: j

Transmission Losses.

Schedule Page: 310.9 Line No.: 5 Column: j

Transmission Losses.

Schedule Page: 310.9 Line No.: 8 Column: b

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 8 Column: j

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 9 Column: j

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 10 Column: b

Sacramento Municipal Utility District - FERC 250 - Contract termination date: December 31, 2014.

Schedule Page: 310.9 Line No.: 11 Column: j

Reserve Share.

Schedule Page: 310.9 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 13 Column: j

Settlement Adjustment.

Schedule Page: 310.9 Line No.: 14 Column: b

Salt River Project - WSPP - Contract termination date: December 31, 2009.

Schedule Page: 310.10 Line No.: 1 Column: j

Transmission Losses.

Schedule Page: 310.10 Line No.: 5 Column: b

Seattle City Light - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 289)] - Contract termination date: October 31, 2014.

Schedule Page: 310.10 Line No.: 5 Column: j

Transmission Losses.

Schedule Page: 310.10 Line No.: 6 Column: j

Reserve Share.

Schedule Page: 310.10 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 9 Column: j

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 12 Column: j

Settlement Adjustment.

Schedule Page: 310.10 Line No.: 13 Column: j

Transmission Losses.

Schedule Page: 310.11 Line No.: 1 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 1 Column: j

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 2 Column: b

Sierra Pacific Power Company - FERC 258 - Contract termination date: February 28, 2009.

Schedule Page: 310.11 Line No.: 3 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.: 3 Column: j

Transmission Losses.

Schedule Page: 310.11 Line No.: 4 Column: j

Transmission Losses.

Schedule Page: 310.11 Line No.: 5 Column: j

Reserve Share.

Schedule Page: 310.11 Line No.: 6 Column: a

Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.11 Line No.: 9 Column: a

Complete name is State of California Department of Water Resources.

Schedule Page: 310.11 Line No.: 11 Column: j

Transmission Losses.

Schedule Page: 310.11 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 13 Column: j

Settlement Adjustment.

Schedule Page: 310.11 Line No.: 14 Column: b

TransAlta Energy Marketing, Inc. - FERC T-12 - Contract termination date: December 31, 2010.

Schedule Page: 310.12 Line No.: 1 Column: j

Transmission Losses.

Schedule Page: 310.12 Line No.: 2 Column: j

Liquidated Damages.

Schedule Page: 310.12 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GENERATION & TRANSMISSION" ON PAGES

FOOTNOTE DATA

310-310.13:
Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.12 Line No.: 4 Column: j

Transmission Losses.

Schedule Page: 310.12 Line No.: 7 Column: j

Reserve Share.

Schedule Page: 310.12 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 310.12 Line No.: 9 Column: j

Settlement Adjustment.

Schedule Page: 310.12 Line No.: 12 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.12 Line No.: 13 Column: j

Unauthorized use charges.

Schedule Page: 310.13 Line No.: 1 Column: b

Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.13 Line No.: 3 Column: j

Transmission Losses.

Schedule Page: 310.13 Line No.: 5 Column: b

Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.13 Line No.: 5 Column: j

The negative revenue reported on this line reflects test energy generated at the Glenrock, High Plains and MacFadden Ridge 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: 310.13 Line No.: 6 Column: j

Recognition and reporting of gains and losses on bookouts under authoritative accounting guidance.

Schedule Page: 310.13 Line No.: 7 Column: j

Recognition and reporting of gains and losses on energy trading contracts under authoritative accounting guidance.

Schedule Page: 310.13 Line No.: 8 Column: j

Represents the difference between actual nonrequirement sales revenues for the period as reflected on the individual line items within this schedule, and the accruals charged to account 447 during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	21,376,391	21,838,417
5	(501) Fuel	620,266,055	624,912,062
6	(502) Steam Expenses	35,509,089	37,487,518
7	(503) Steam from Other Sources	3,597,576	3,371,385
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,904,528	4,303,303
10	(506) Miscellaneous Steam Power Expenses	43,559,253	43,572,425
11	(507) Rents	450,415	281,381
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	728,663,307	735,766,491
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,970,114	6,008,903
16	(511) Maintenance of Structures	22,825,065	24,834,108
17	(512) Maintenance of Boiler Plant	94,433,581	86,675,457
18	(513) Maintenance of Electric Plant	33,727,522	28,874,080
19	(514) Maintenance of Miscellaneous Steam Plant	12,681,273	12,753,101
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	169,637,555	159,145,649
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	898,300,862	894,912,140
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	9,385,219	8,826,196
45	(536) Water for Power	290,209	301,387
46	(537) Hydraulic Expenses	3,518,610	4,090,454
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	15,385,413	15,930,741
49	(540) Rents	183,444	141,239
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	28,762,895	29,290,017
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	84,358	2,681
54	(542) Maintenance of Structures	1,207,112	1,225,169
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,600,540	1,437,284
56	(544) Maintenance of Electric Plant	1,515,716	1,572,617
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,539,316	2,151,781
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,947,042	6,389,532
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	35,709,937	35,679,549

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	316,964	218,466
63	(547) Fuel	461,743,015	466,962,755
64	(548) Generation Expenses	15,739,485	17,845,036
65	(549) Miscellaneous Other Power Generation Expenses	18,635,853	10,943,849
66	(550) Rents	1,861,264	6,739,843
67	TOTAL Operation (Enter Total of lines 62 thru 66)	498,296,581	502,709,949
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	1,544,031	1,280,348
71	(553) Maintenance of Generating and Electric Plant	14,986,840	5,911,258
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,321,906	482,926
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	17,852,777	7,674,532
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	516,149,358	510,384,481
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	456,211,649	754,189,849
77	(556) System Control and Load Dispatching	1,514,461	1,997,891
78	(557) Other Expenses	49,819,215	56,143,944
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	507,545,325	812,331,684
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,957,705,482	2,253,307,854
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	6,088,583	7,808,710
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,347,455	7,114,390
87	(561.3) Load Dispatch-Transmission Service and Scheduling		83,728
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	76,671	73,289
91	(561.7) Generation Interconnection Studies	899,582	1,264,738
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,506,478	1,869,851
94	(563) Overhead Lines Expenses	245,152	93,337
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	117,161,210	121,167,183
97	(566) Miscellaneous Transmission Expenses	2,393,112	1,795,131
98	(567) Rents	1,656,975	822,667
99	TOTAL Operation (Enter Total of lines 83 thru 98)	138,375,218	142,093,024
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	35,453	9,822
102	(569) Maintenance of Structures	788	3,284
103	(569.1) Maintenance of Computer Hardware	79,505	290,283
104	(569.2) Maintenance of Computer Software	974,621	636,171
105	(569.3) Maintenance of Communication Equipment	3,005,647	3,199,160
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	10,549,624	11,093,119
108	(571) Maintenance of Overhead Lines	19,620,066	16,204,998
109	(572) Maintenance of Underground Lines	51,599	
110	(573) Maintenance of Miscellaneous Transmission Plant	182,001	480,533
111	TOTAL Maintenance (Total of lines 101 thru 110)	34,499,304	31,917,370
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	172,874,522	174,010,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	19,654,389	20,296,814
135	(581) Load Dispatching	13,439,746	12,782,671
136	(582) Station Expenses	3,879,687	4,574,167
137	(583) Overhead Line Expenses	5,794,824	5,392,347
138	(584) Underground Line Expenses	305	403
139	(585) Street Lighting and Signal System Expenses	207,152	222,030
140	(586) Meter Expenses	6,713,560	7,204,688
141	(587) Customer Installations Expenses	12,459,259	11,063,638
142	(588) Miscellaneous Expenses	7,441,400	8,389,281
143	(589) Rents	3,196,255	3,038,169
144	TOTAL Operation (Enter Total of lines 134 thru 143)	72,786,577	72,964,208
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	7,535,970	6,421,892
147	(591) Maintenance of Structures	2,015,990	2,030,161
148	(592) Maintenance of Station Equipment	12,800,357	11,547,226
149	(593) Maintenance of Overhead Lines	83,336,655	85,001,337
150	(594) Maintenance of Underground Lines	22,486,595	23,539,909
151	(595) Maintenance of Line Transformers	1,105,880	1,116,622
152	(596) Maintenance of Street Lighting and Signal Systems	4,217,687	4,138,856
153	(597) Maintenance of Meters	5,637,023	5,212,174
154	(598) Maintenance of Miscellaneous Distribution Plant	3,546,007	3,391,891
155	TOTAL Maintenance (Total of lines 146 thru 154)	142,682,164	142,400,068
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	215,468,741	215,364,276
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,554,096	2,477,949
160	(902) Meter Reading Expenses	22,520,219	25,289,712
161	(903) Customer Records and Collection Expenses	56,280,326	56,637,149
162	(904) Uncollectible Accounts	12,175,795	14,674,714
163	(905) Miscellaneous Customer Accounts Expenses	254,571	229,561
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	93,785,007	99,309,085

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/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	286,417	247,987
168	(908) Customer Assistance Expenses	66,102,006	51,829,080
169	(909) Informational and Instructional Expenses	4,924,267	4,101,589
170	(910) Miscellaneous Customer Service and Informational Expenses	150,054	63,857
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	71,462,744	56,242,513
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	72,874,820	67,200,789
182	(921) Office Supplies and Expenses	11,031,087	11,470,988
183	(Less) (922) Administrative Expenses Transferred-Credit	25,866,775	21,538,493
184	(923) Outside Services Employed	11,039,350	11,890,876
185	(924) Property Insurance	23,970,317	31,882,383
186	(925) Injuries and Damages	7,434,336	9,475,122
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	16,464,747	11,630,262
190	(929) (Less) Duplicate Charges-Cr.	3,420,842	3,987,182
191	(930.1) General Advertising Expenses	35,761	35,163
192	(930.2) Miscellaneous General Expenses	19,659,625	18,540,495
193	(931) Rents	6,199,584	6,318,703
194	TOTAL Operation (Enter Total of lines 181 thru 193)	139,422,010	142,919,106
195	Maintenance		
196	(935) Maintenance of General Plant	23,197,501	27,125,031
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	162,619,511	170,044,137
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,673,916,007	2,968,278,259

FOOTNOTE DATA

Schedule Page: 320 Line No.: 187 Column: b

Pensions and benefits are charged to functional accounts, which is consistent with where labor is charged. The following table summarizes the pension and benefit expense that was charged to the functional accounts.

	Years Ended December 31, 2009	2008
Pension & Benefits Expense	$ 143,975,955	$ 145,242,536

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Power Purchases					
2	AES Wind Generation, Inc.	LU		NA	NA	NA
3	Albany, City of	AD		NA	NA	NA
4	Albany, City of	LU		NA	NA	NA
5	Anaheim, City of	OS		NA	NA	NA
6	Anaheim, City of	SF		NA	NA	NA
7	Arizona Public Service Company	AD		NA	NA	NA
8	Arizona Public Service Company	LF		NA	NA	NA
9	Arizona Public Service Company	OS		NA	NA	NA
10	Arizona Public Service Company	SF		NA	NA	NA
11	Avista Corporation	OS		NA	NA	NA
12	Avista Corporation	SF		NA	NA	NA
13	Azusa, City of	SF		NA	NA	NA
14	BP Energy Company	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
134,819				4,783,383		4,783,383	2
5					284	284	3
660				42,080		42,080	4
25				300		300	5
2,966				101,804		101,804	6
125					7,500	7,500	7
59,100				1,788,275		1,788,275	8
3,700				110,200		110,200	9
90,828				2,778,332		2,778,332	10
					500	500	11
103,505				3,087,419	7,887	3,095,306	12
2				36		36	13
120,072				4,333,194	-13,877,372	-9,544,178	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ballard Hog Farms Inc.	AD		NA	NA	NA
2	Ballard Hog Farms Inc.	LU		0.01	NA	NA
3	Barclays Bank PLC	AD		NA	NA	NA
4	Barclays Bank PLC	SF		NA	NA	NA
5	Beaver City	LF		NA	NA	NA
6	Bell Mountain Hydro, LLC	LU		NA	NA	NA
7	Amy Ranch Hydro	LU		NA	NA	NA
8	Benton County Public Utility District	SF		NA	NA	NA
9	Big Top, LLC	LU		NA	NA	NA
10	Biomass One, L.P.	LU		22.5	18.7	15.0
11	Birch Creek Hydro	LU		NA	NA	NA
12	Black Hills Power, Inc.	AD		NA	NA	NA
13	Black Hills Power, Inc.	LU		NA	NA	NA
14	Black Hills Power, Inc.	OS		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					47	47	1
107			277	5,515		5,792	2
349					27,735	27,735	3
529,132				20,190,571	-25,952,421	-5,761,850	4
68				5,657		5,657	5
219				17,163	-4,551	12,612	6
1,497				76,617		76,617	7
4,000				42,000		42,000	8
822				48,265		48,265	9
127,002			2,399,625	17,165,610	5,526,235	25,091,470	10
12,029				656,408		656,408	11
-73					88,677	88,677	12
2,450					1,159,656	1,159,656	13
40				1,340		1,340	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Black Hills Power, Inc.	SF		NA	NA	NA
2	Black Hills Wyoming, Inc.	SF		NA	NA	NA
3	Blanding City	LF		NA	NA	NA
4	Harold Foster & Robert Walker	LU		NA	NA	NA
5	Bonneville Power Administration	AD		NA	NA	NA
6	Bonneville Power Administration	LF		575	575	478
7	Bonneville Power Administration	LF		NA	NA	NA
8	Bonneville Power Administration	OS		NA	NA	NA
9	Bonneville Power Administration	AD		NA	NA	NA
10	Bonneville Power Administration	SF		NA	NA	NA
11	Burbank, City of	AD		NA	NA	NA
12	Burbank, City of	SF		NA	NA	NA
13	Butter Creek Power, LLC	LU		NA	NA	NA
14	CDM Hydroelectric Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
29,438				1,067,124		1,067,124	1
3,895				116,590		116,590	2
400				29,966		29,966	3
1,006				34,808		34,808	4
					-47,083	-47,083	5
			49,697,250			49,697,250	6
					1,845,106	1,845,106	7
					331,217	331,217	8
					80	80	9
304,490				5,987,323	90,715	6,078,038	10
286					17,117	17,117	11
26,026				934,213		934,213	12
5,011				223,705		223,705	13
30,019				1,634,595		1,634,595	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	California Independent System Operator	AD		NA	NA	NA
2	California Independent System Operator	SF		NA	NA	NA
3	Cargill Power Markets, LLC	AD		NA	NA	NA
4	Cargill Power Markets, LLC	OS		NA	NA	NA
5	Cargill Power Markets, LLC	SF		NA	NA	NA
6	Central Oregon Irrigation District	LU		4.4	4.1	3.3
7	Chelan County PUD #1	LU		NA	NA	NA
8	Chelan County PUD #1	SF		NA	NA	NA
9	Chevron U.S.A. Inc.	LU		NA	NA	NA
10	Citigroup Energy, Inc.	AD		NA	NA	NA
11	Citigroup Energy, Inc.	SF		NA	NA	NA
12	City of Buffalo	LU		0.2	0.2	0.2
13	Clatskanie People's Utility District	SF		NA	NA	NA
14	Colorado River Commission of Nevada	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
750					19,795	19,795	1
513,351				18,029,512		18,029,512	2
314					11,387	11,387	3
1,328				28,608		28,608	4
1,591,545				48,538,541		48,538,541	5
28,427			456,550	2,618,115		3,074,665	6
353,761					3,686,164	3,686,164	7
36,873				865,140	2,664	867,804	8
6,122				329,217		329,217	9
227					9,248	9,248	10
548,286				16,467,483	-8,082,194	8,385,289	11
1,870			28,884	153,704		182,588	12
3,391				100,780		100,780	13
350					14,778	14,778	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Colorado River Commission of Nevada	SF		NA	NA	NA
2	Colorado Springs Utilities	SF		NA	NA	NA
3	Commercial Energy Management, Inc.	LU		NA	NA	NA
4	Conoco Inc.	SF		NA	NA	NA
5	Constellation Energy Commodities Group	AD		NA	NA	NA
6	Constellation Energy Commodities Group	OS		NA	NA	NA
7	Constellation Energy Commodities Group	SF		NA	NA	NA
8	Cottonwood Hydro LLC	IU		0.3	0.4	0.3
9	Cowlitz County PUD #1	OS		NA	NA	NA
10	Credit Suisse Energy LLC	AD		NA	NA	NA
11	Credit Suisse Energy LLC	SF		NA	NA	NA
12	Cameron A. Curtiss	LU		NA	NA	NA
13	DB Energy Trading LLC	SF		NA	NA	NA
14	DR Johnson Lumber Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
175				8,062		8,062	1
80				4,560		4,560	2
1,596				83,543		83,543	3
87,238				3,174,667		3,174,667	4
1,171					180,242	180,242	5
14,157				619,091		619,091	6
215,818				9,549,874	-11,836,097	-2,286,223	7
2,625			6,080	135,178		141,258	8
					489,437	489,437	9
647					61,767	61,767	10
333,801				18,489,790	-8,455,728	10,034,062	11
99				6,409		6,409	12
207,045				6,071,390		6,071,390	13
56,756				3,672,439		3,672,439	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Davis County Waste Management	AD		NA	NA	NA
2	Davis County Waste Management	LU		NA	NA	NA
3	Deschutes Valley Water District	LU		5.8	4.0	2.7
4	Deseret Power Electric Cooperative	LF		100	100	89
5	Deutsche Bank AG	SF		NA	NA	NA
6	Douglas County Forest Products	AD		NA	NA	NA
7	Douglas County Forest Products	IU		NA	NA	NA
8	Douglas County PUD #1	AD		NA	NA	NA
9	Douglas County PUD #1	AD		NA	NA	NA
10	Douglas County PUD #1	LU		NA	NA	NA
11	Douglas County PUD #1	OS		NA	NA	NA
12	Douglas County PUD #1	SF		NA	NA	NA
13	Douglas County Public Works	LU		0.5	0.6	0.3
14	Draper Irrigation Company	IU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6					307	307	1
899				46,284		46,284	2
26,184			571,014	2,712,673		3,283,687	3
736,900			13,856,971	13,018,626	3,655,828	30,531,425	4
					-2,819,636	-2,819,636	5
					-1,645	-1,645	6
1,308				42,644		42,644	7
					-37,974	-37,974	8
					-92,949	-92,949	9
214,192					2,871,143	2,871,143	10
38,224				757,381		757,381	11
14,825				468,700	567	469,267	12
3,407			53,513	395,265		448,778	13
513				28,422		28,422	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Dry Creek LLC	LU		NA	NA	NA
2	Dynegy Power Marketing	SF		NA	NA	NA
3	EDF Trading North America, LLC	OS		NA	NA	NA
4	EDF Trading North America, LLC	SF		NA	NA	NA
5	Eagle Point Irrigation District	LU		0.7	0.5	0.3
6	El Paso Electric Company	AD		NA	NA	NA
7	El Paso Electric Company	SF		NA	NA	NA
8	Endure Energy, LLC	SF		NA	NA	NA
9	Eugene Water & Electric Board	SF		NA	NA	NA
10	Eurus Combine Hills I, LLC	LU		NA	NA	NA
11	Evergreen BioPower, LLC	AD		NA	NA	NA
12	Evergreen BioPower, LLC	LU		NA	NA	NA
13	ExxonMobile Production Company	LU		NA	NA	NA
14	Falls Creek H.P. Limited Partnership	LU		3.1	3.4	1.4
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
11,809				606,928		606,928	1
24,525				864,675		864,675	2
3,100				192,200		192,200	3
95,193				2,812,921	-5,691,159	-2,878,238	4
2,901			38,860	316,151		355,011	5
-37					-2,505	-2,505	6
43,319				1,056,212	79	1,056,291	7
20,687				651,636		651,636	8
33,842				863,230		863,230	9
104,572				3,631,783		3,631,783	10
2,787					145,417	145,417	11
40,372				1,971,619		1,971,619	12
645,863				30,821,131		30,821,131	13
15,942			199,567	1,629,316		1,828,883	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Farmers Irrigation District	LU		3.6	3.4	2.0
2	Loyd Fery	LU		NA	NA	NA
3	Fillmore City	LF		NA	NA	NA
4	Finley BioEnergy, LLC	LU		NA	NA	NA
5	Fortis Energy Marketing & Trading GP	SF		NA	NA	NA
6	Four Corners Windfarm, LLC	LU		NA	NA	NA
7	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
8	Shoshone Irrigation District	LU		2.5	1.4	1.0
9	General Chemical Corporation	OS		NA	NA	NA
10	George DeRuyter & Sons Dairy	IU		0.7	1.0	0.7
11	Georgetown Irrigation Company	LU		NA	NA	NA
12	Gila River Power, L.P.	OS		NA	NA	NA
13	Gila River Power, L.P.	SF		NA	NA	NA
14	Glendale, City of	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
22,859			308,228	2,354,510		2,662,738	1
246				15,943		15,943	2
182				19,680		19,680	3
27,365				1,765,302		1,765,302	4
35,600				1,197,430	-246,513	950,917	5
5,304				271,267		271,267	6
5,652				282,143		282,143	7
9,596			157,630	375,589		533,219	8
1,792				26,700		26,700	9
6,427			2,014	324,304		326,318	10
2,358				126,441		126,441	11
785				28,400		28,400	12
145,607				4,588,713		4,588,713	13
24				1,008		1,008	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grand Valley Power	LF		NA	NA	NA
2	Grant County PUD #2	AD		NA	NA	NA
3	Grant County PUD #2	AD		NA	NA	NA
4	Grant County PUD #2	LF		14	NA	NA
5	Grant County PUD #2	LU		NA	NA	NA
6	Grant County PUD #2	OS		NA	NA	NA
7	Grant County PUD #2	SF		NA	NA	NA
8	Heber Light & Power Company	LF		NA	NA	NA
9	Hermiston Generating Company, L.P.	AD		NA	NA	NA
10	Hermiston Generating Company, L.P.	LU		240	240	218
11	Hill Air Force Base	LU		NA	NA	NA
12	Hurricane, City of	LF		NA	NA	NA
13	Iberdrola Renewables, Inc.	AD		NA	NA	NA
14	Iberdrola Renewables, Inc.	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
83				13,975		13,975	1
					-520,156	-520,156	2
					-91,767	-91,767	3
87,600			84,063	5,436,614	325,807	5,846,484	4
1,124,741				12,153,646	2,638,046	14,791,692	5
					2,500	2,500	6
37,744				1,129,583	3,155	1,132,738	7
6,106				516,520		516,520	8
-1					224,032	224,032	9
1,550,652			34,971,330	53,986,161	289,434	89,246,925	10
12,317				572,234		572,234	11
1,885				141,345		141,345	12
457					10,409	10,409	13
439,515				18,949,325	-2,043,816	16,905,509	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Idaho Falls, City of	LU		NA	NA	NA
2	Idaho Power Company	AD		NA	NA	NA
3	Idaho Power Company	OS		NA	NA	NA
4	Idaho Power Company	SF		NA	NA	NA
5	Idaho Power Company	SF		NA	NA	NA
6	Integrys Energy Services, Inc.	SF		NA	NA	NA
7	Intermountain Power Agency	LU		NA	NA	NA
8	International Paper	OS		NA	NA	NA
9	J. Aron & Company	AD		NA	NA	NA
10	J. Aron & Company	SF		NA	NA	NA
11	J.P. Morgan Ventures Energy Corp.	OS		NA	NA	NA
12	J.P. Morgan Ventures Energy Corp.	SF		NA	NA	NA
13	JPMorgan Chase Bank, National Assoc.	SF		NA	NA	NA
14	Kennecott Utah Copper LLC	IU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
48,419					2,784,700	2,784,700	1
-16					-752	-752	2
4,550				60,425		60,425	3
36,425					1,290,992	1,290,992	4
21,675				759,204	2,535	761,739	5
1,200				42,600		42,600	6
577,331				25,739,038		25,739,038	7
357,354				23,669,663		23,669,663	8
11					1,183	1,183	9
49,197				1,766,945	-6,891,389	-5,124,444	10
50				1,250		1,250	11
401,229				12,904,411	-242,633	12,661,778	12
					-2,541,248	-2,541,248	13
183,993				13,818,803		13,818,803	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Kennecott Utah Copper LLC	LU		NA	NA	NA
2	L&M Angus Ranch, LLC	LU		NA	NA	NA
3	Lacomb Irrigation District	LU		NA	NA	NA
4	Box Canyon Limited Partnership	LU		2.3	2.9	1.3
5	Los Angeles Dept. of Water & Power	AD		NA	NA	NA
6	Los Angeles Dept. of Water & Power	OS		NA	NA	NA
7	Los Angeles Dept. of Water & Power	SF		NA	NA	NA
8	Lower Valley Energy, Inc.	IU		NA	NA	NA
9	Luckey, Paul	LU		NA	NA	NA
10	Macquarie Cook Power Inc.	SF		NA	NA	NA
11	Magnesium Corporation of America	IU		NA	NA	NA
12	Magnesium Corporation of America	LF		NA	NA	NA
13	Marsh Valley Hydro & Electric Company	LU		NA	NA	NA
14	Middle Fork Irrigation District	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					9,735,404	9,735,404	1
1,421				77,761		77,761	2
4,717				155,616	32,869	188,485	3
14,593			219,747	1,578,567		1,798,314	4
32					2,334	2,334	5
840				6,720	38,270	44,990	6
110,676				3,300,523	5,893	3,306,416	7
1,815				105,464		105,464	8
287				34,081		34,081	9
62,884				2,216,834	-304,027	1,912,807	10
119,269				3,717,889		3,717,889	11
					1,537,460	1,537,460	12
5,229				285,891		285,891	13
22,904				1,110,981		1,110,981	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Mink Creek Hydro	LU		NA	NA	NA
2	Mirant Americas Energy Marketing, L.P.	SF		NA	NA	NA
3	Modesto Irrigation District	SF		NA	NA	NA
4	Monsanto Company	IU		NA	NA	NA
5	Morgan City	LF		NA	NA	NA
6	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
7	Morgan Stanley Capital Group, Inc.	IF		100	100	100
8	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
9	Mountain Energy, Inc.	LU		NA	NA	NA
10	Mountain Wind Power II, LLC	AD		NA	NA	NA
11	Mountain Wind Power II, LLC	LU		NA	NA	NA
12	Mountain Wind Power, LLC	LU		NA	NA	NA
13	Nephi City	LF		NA	NA	NA
14	Nevada Power Company	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,537				558,838		558,838	1
120				6,960		6,960	2
400				42,800		42,800	3
					13,410,115	13,410,115	4
27				3,187		3,187	5
3,482					155,040	155,040	6
328,800			1,515,000	17,709,840		19,224,840	7
1,390,765				63,709,915	-16,960,502	46,749,413	8
79				5,056		5,056	9
812					33,618	33,618	10
202,840				13,116,241	-8,166	13,108,075	11
128,330				7,199,623		7,199,623	12
16				1,558		1,558	13
-11					-537	-537	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Nevada Power Company	SF		NA	NA	NA
2	Nicholson Sunnybar Ranch	AD		NA	NA	NA
3	Nicholson Sunnybar Ranch	LU		NA	NA	NA
4	HDI Associates V, LP	LU		0.4	0.5	0.2
5	NorthWestern Energy	SF		NA	NA	NA
6	Northpoint Energy Solutions Inc.	SF		NA	NA	NA
7	Nucor Corporation	IF		NA	NA	NA
8	O.J. Power Company	LU		NA	NA	NA
9	Occidental Power Services, Inc.	SF		NA	NA	NA
10	Odell Creek Hydroelectric Investors	LU		0.03	0.04	0.02
11	Oregon Environmental Industries, LLC	LU		NA	NA	NA
12	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
13	PPL EnergyPlus, LLC	SF		NA	NA	NA
14	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
33,764				1,321,610	63,232	1,384,842	1
					1,188	1,188	2
1,726				93,519		93,519	3
1,928			38,035	205,760		243,795	4
1,118				22,932	10,228	33,160	5
18,993				610,487		610,487	6
					4,722,600	4,722,600	7
767				38,324		38,324	8
11,350				370,372		370,372	9
151			2,797	14,260		17,057	10
18,367				891,523		891,523	11
10,188				441,349		441,349	12
21,116				882,746		882,746	13
6,435				287,528		287,528	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Pacific Gas & Electric Company	SF		NA	NA	NA
2	Pacific Northwest Generating Coop.	SF		NA	NA	NA
3	Pacific Summit Energy LLC	AD		NA	NA	NA
4	Pacific Summit Energy LLC	SF		NA	NA	NA
5	Pasadena, City of	OS		NA	NA	NA
6	Payson City Corporation	LF		NA	NA	NA
7	Platte River Power Authority	SF		NA	NA	NA
8	Portland General Electric Company	AD		NA	NA	NA
9	Portland General Electric Company	LF		NA	NA	NA
10	Portland General Electric Company	SF		NA	NA	NA
11	Powerex Corporation	SF		NA	NA	NA
12	Preston City Hydro	LU		NA	NA	NA
13	Provo City	LF		NA	NA	NA
14	Public Service Company of Colorado	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,816				260,230		260,230	1
4,419				188,931		188,931	2
11					456	456	3
127,842				4,723,877		4,723,877	4
2,376				14,200		14,200	5
14				1,531		1,531	6
3,088					87,848	87,848	7
					537,165	537,165	8
12,024					359,000	359,000	9
122,653				4,452,438	14,704	4,467,142	10
232,672				10,424,398		10,424,398	11
1,869				91,864		91,864	12
143				11,429		11,429	13
581					41,365	41,365	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Public Service Company of Colorado	SF		NA	NA	NA
2	Public Service Company of New Mexico	SF		NA	NA	NA
3	PUD #1 of Lewis County	AD		NA	NA	NA
4	PUD #1 of Lewis County	LF		NA	NA	NA
5	Puget Sound Energy, Inc.	SF		NA	NA	NA
6	RRI Energy Services, Inc.	SF		NA	NA	NA
7	Rainbow Energy Marketing Corporation	OS		NA	NA	NA
8	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
9	Ralphs Ranch, Inc.	LU		NA	NA	NA
10	Redding, City of	SF		NA	NA	NA
11	Riverside, City of	OS		NA	NA	NA
12	Rocky Mountain Generation Cooperative	SF		NA	NA	NA
13	Roseburg Forest Products Co.	LU		NA	NA	NA
14	Rough & Ready Lumber Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,640				390,767		390,767	1
134,616				3,607,841	122,818	3,730,659	2
669					18,153	18,153	3
6,267				166,177		166,177	4
175,631				6,018,315	13,463	6,031,778	5
2,100				113,400		113,400	6
912				38,660		38,660	7
79,733				2,003,087		2,003,087	8
217				25,757		25,757	9
780				44,500		44,500	10
2,585				21,105		21,105	11
13,278				313,383		313,383	12
163,561				9,337,270		9,337,270	13
8,557				553,304		553,304	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Roush Hydro, Inc.	LU		NA	NA	NA
2	Sacramento Municipal Utility District	AD		NA	NA	NA
3	Sacramento Municipal Utility District	LF		NA	NA	NA
4	Sacramento Municipal Utility District	OS		NA	NA	NA
5	Sacramento Municipal Utility District	SF		NA	NA	NA
6	Salt River Project	AD		NA	NA	NA
7	Salt River Project	SF		NA	NA	NA
8	San Diego Gas & Electric Company	SF		NA	NA	NA
9	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
10	Santiam Water Control District	LU		0.2	0.2	0.2
11	Seattle City Light	SF		NA	NA	NA
12	Sempra Energy Solutions LLC	SF		NA	NA	NA
13	Sempra Energy Trading LLC	SF		NA	NA	NA
14	Sempra Generation	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
213				13,793		13,793	1
					199,170	199,170	2
219,000				3,519,330		3,519,330	3
					143,800	143,800	4
20,422				736,687		736,687	5
49					1,531	1,531	6
235,642				7,963,852	40	7,963,892	7
6,435				241,930		241,930	8
9,349				407,621		407,621	9
1,524			13,632	140,837		154,469	10
92,734				2,692,027	4,628	2,696,655	11
2,400				54,736		54,736	12
511,504				25,579,036	-18,603,346	6,975,690	13
5,907				212,358		212,358	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy North America (US), L.P.	AD		NA	NA	NA
2	Shell Energy North America (US), L.P.	SF		NA	NA	NA
3	Sierra Pacific Power Company	AD		NA	NA	NA
4	Sierra Pacific Power Company	SF		NA	NA	NA
5	Simplot Phosphates, LLC	LU		10	12	9
6	Slate Creek Hydro Company, Inc.	LU		2.3	1.6	1.0
7	Snohomish Public Utility District No.1	SF		NA	NA	NA
8	Southern California Edison Company	AD		NA	NA	NA
9	Southern California Edison Company	OS		NA	NA	NA
10	Southern California Edison Company	SF		NA	NA	NA
11	Southwestern Public Service Company	SF		NA	NA	NA
12	Spanish Fork City	LF		NA	NA	NA
13	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
14	Springville City	LF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
25					4,547	4,547	1
443,320				17,209,750	-18,626,851	-1,417,101	2
-136					-7,190	-7,190	3
9,075				259,015	20,414	279,429	4
72,205			395,200	2,749,243		3,144,443	5
7,860			119,741	754,531		874,272	6
77,639				2,219,045		2,219,045	7
7					280	280	8
41,793				832,487		832,487	9
67,226				2,225,499		2,225,499	10
1,249				38,885		38,885	11
41				3,786		3,786	12
46,415				2,407,176		2,407,176	13
29				3,748		3,748	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
2	Strawberry Electric Service District	LF		NA	NA	NA
3	Sunderland Dairy Inc.	LU		0.02	0.02	0.02
4	Sunnyside Cogeneration Associates	LU		51.8	52.7	49.6
5	Tacoma, City of	SF		NA	NA	NA
6	Tesoro Refining and Marketing Company	IU		NA	NA	NA
7	Thayn Hydro LLC	LU		0.3	0.4	0.3
8	The Energy Authority	SF		NA	NA	NA
9	Three Buttes Windpower, LLC	LU		NA	NA	NA
10	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
11	TransAlta Energy Marketing Inc.	AD		NA	NA	NA
12	TransAlta Energy Marketing Inc.	IF		NA	NA	NA
13	TransAlta Energy Marketing Inc.	SF		NA	NA	NA
14	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,035				67,939		67,939	1
56				4,639		4,639	2
100			1,296	3,238		4,534	3
410,935			10,377,743	14,657,326		25,035,069	4
38,657				986,016	2,149	988,165	5
191,926				14,317,423		14,317,423	6
2,701			69,204	192,828		262,032	7
42,638				1,489,506		1,489,506	8
39,975				2,399,390		2,399,390	9
8,109				271,709		271,709	10
195					10,510	10,510	11
1,315,200				46,552,378	-628,752	45,923,626	12
244,194				7,718,296		7,718,296	13
8,400				389,500		389,500	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Tri-State Generation & Transmission	LF		35	33	30
2	Tri-State Generation & Transmission	OS		NA	NA	NA
3	Tri-State Generation & Transmission	SF		NA	NA	NA
4	Tucson Electric Power Company	OS		NA	NA	NA
5	Tucson Electric Power Company	SF		NA	NA	NA
6	Turlock Irrigation District	SF		NA	NA	NA
7	UBS Securities LLC	SF		NA	NA	NA
8	UBS Warburg Energy LLC	SF		25	NA	NA
9	UNS Electric, Inc.	SF		NA	NA	NA
10	Utah Assoc. Municipal Power Systems	SF		NA	NA	NA
11	Utah Municipal Power Agency	OS		NA	NA	NA
12	Utah Municipal Power Agency	SF		NA	NA	NA
13	Wadeland South LLC	LU		0.03	0.01	0.01
14	Wagon Trail, LLC	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
199,507			8,395,800	4,560,730		12,956,530	1
770				28,040		28,040	2
39,732				1,358,380	17,655	1,376,035	3
1,125				13,700		13,700	4
52,471				1,503,409	1,862	1,505,271	5
2,402				75,419		75,419	6
					-15,264	-15,264	7
800			662,250	29,000	-4,321,432	-3,630,182	8
616				24,320		24,320	9
30				900		900	10
7,194				253,433		253,433	11
2,937				105,689		105,689	12
41			571	1,314		1,885	13
2,332				109,673		109,673	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Walla Walla, City of	LU		2.0	1.7	1.5
2	Ward Butte Windfarm, LLC	LU		NA	NA	NA
3	Warm Springs Forest Products	LU		NA	NA	NA
4	Weber County, State of Utah	LU		NA	NA	NA
5	Western Area Power Administration	AD		NA	NA	NA
6	Western Area Power Administration	OS		NA	NA	NA
7	Western Area Power Administration	SF		NA	NA	NA
8	Wolverine Creek Energy LLC	LU		NA	NA	NA
9	Yakima-Tieton Irrigation District	LU		NA	NA	NA
10	Accrual True-up	NA		NA	NA	NA
11	Line Loss Return	AD		NA	NA	NA
12	Bookout Purchases	AD		NA	NA	NA
13	MWH Settlement	AD		NA	NA	NA
14	Trade Purchases	AD		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
12,276			140,750	1,620,407		1,761,157	1
6,297				281,294		281,294	2
1,682				41,284		41,284	3
5,669				256,936		256,936	4
16							5
55				1,375		1,375	6
29,684				675,131	11,146	686,277	7
153,761				8,392,264		8,392,264	8
7,012				425,826		425,826	9
					19,889,611	19,889,611	10
					-1,081,438	-1,081,438	11
-9,811,714					-314,938,844	-314,938,844	12
					-1,128,353	-1,128,353	13
					-45,464,949	-45,464,949	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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	Liquidated Damage	AD		NA	NA	NA
2						
3	Power Exchanges					
4	Arizona Public Service Company	AD	306	NA	NA	NA
5	Arizona Public Service Company	EX	306	NA	NA	NA
6	Avista Corporation	EX	554	NA	NA	NA
7	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
8	Black Hills Power, Inc.	EX	246	NA	NA	NA
9	Bonneville Power Administration	AD	237	NA	NA	NA
10	Bonneville Power Administration	AD	NA	NA	NA	NA
11	Bonneville Power Administration	AD	T-11	NA	NA	NA
12	Bonneville Power Administration	AD	T-12	NA	NA	NA
13	Bonneville Power Administration	EX	237	NA	NA	NA
14	Bonneville Power Administration	EX	256	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-500,000	-500,000	1
							2
							3
	285				10,120	10,120	4
	570,761	571,592			11,045,321	11,045,321	5
	1,621						6
	16,022	3,804			338,429	338,429	7
	179						8
		61,320			200	200	9
					-1,136,133	-1,136,133	10
	20	194			-9,075	-9,075	11
	3,016				286,667	286,667	12
					-87,922	-87,922	13
	6,920	6,920			-55,360	-55,360	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Bonneville Power Administration	EX	347	NA	NA	NA
2	Bonneville Power Administration	EX	368	NA	NA	NA
3	Bonneville Power Administration	EX	554	NA	NA	NA
4	Bonneville Power Administration	EX	(16)	NA	NA	NA
5	Bonneville Power Administration	EX	T-11	NA	NA	NA
6	Bonneville Power Administration	EX	T-12	NA	NA	NA
7	Chelan County PUD #1	EX	554	NA	NA	NA
8	Chelan County PUD #1	NA	NA	NA	NA	NA
9	Chelan County PUD #1	EX	T-12	NA	NA	NA
10	Colockum Transmission Company	EX	T-12	NA	NA	NA
11	Constellation Energy Commodities Group	EX	T-11	NA	NA	NA
12	Cowlitz County PUD #1	EX	554	NA	NA	NA
13	Deseret Power Electric Cooperative	AD	280	NA	NA	NA
14	Deseret Power Electric Cooperative	EX	280	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	1,449,700	1,442,869			-140,000	-140,000	1
	238,802	238,802					2
	226,808	40,793					3
	9,600,926	9,600,926			-32,071,635	-32,071,635	4
	12,223	8,732			67,935	67,935	5
	98,817	86,417			823,209	823,209	6
		16,969					7
		856					8
		30,809					9
		268,153					10
	1,711	1,610			2,487	2,487	11
	170,681	205,669					12
	408	-3,546			149,873	149,873	13
	32,326	63,968			-1,287,341	-1,287,341	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Emerald Peoples Utility District	AD	351	NA	NA	NA
2	Emerald Peoples Utility District	EX	351	NA	NA	NA
3	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
4	Grant County PUD #2	EX	554	NA	NA	NA
5	Iberdrola Renewables, Inc.	EX	T-11	NA	NA	NA
6	Idaho Power Company	EX	380	NA	NA	NA
7	Intermountain Renewable Power, LLC	EX	T-11	NA	NA	NA
8	Los Angeles Dept. of Water & Power	EX	OV-1	NA	NA	NA
9	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
11	Portland General Electric Company	EX	554	NA	NA	NA
12	Powerex Corporation	EX	T-11	NA	NA	NA
13	Public Service Company of Colorado	EX	319	NA	NA	NA
14	Public Service Company of Colorado	EX	320	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
		-4			93	93	1
		451			-11,283	-11,283	2
	16,435	16,559			-13,283	-13,283	3
		37,574					4
	14,605	9,039			140,424	140,424	5
	263,500	237,712					6
	1,827	1,754			4,938	4,938	7
	1,360				84,693	84,693	8
		1,360			-84,693	-84,693	9
	10,897	538			362,528	362,528	10
	154,417	153,258					11
	909	496			11,916	11,916	12
	6,095						13
	437,975	437,565			1,800,000	1,800,000	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Public Service Company of Colorado	NA	NA	NA	NA	NA
2	Public Service Company of Colorado	EX	T-12	NA	NA	NA
3	Redding, City of	EX	364	NA	NA	NA
4	Seattle City Light	EX	554	NA	NA	NA
5	Sempra Energy Solutions LLC	AD	T-11	NA	NA	NA
6	Sempra Energy Solutions LLC	EX	T-11	NA	NA	NA
7	Tri-State Generation & Transmission	AD	319	NA	NA	NA
8	Tri-State Generation & Transmission	EX	319	NA	NA	NA
9	Tucson Electric Power Company	NA	NA	NA	NA	NA
10	Utah Assoc. Municipal Power Systems	AD	T-11	NA	NA	NA
11	Utah Assoc. Municipal Power Systems	EX	T-11	NA	NA	NA
12	Utah Municipal Power Agency	AD	T-11	NA	NA	NA
13	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
14	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
		2,522					1
	71,133	75,545			-374,024	-374,024	2
	116,859	117,279			18,811	18,811	3
	295,482	301,430			-744,715	-744,715	4
	71	-377			17,988	17,988	5
	6,259	2,484			90,678	90,678	6
					8,085	8,085	7
	6,095				40,200	40,200	8
		10,589					9
	346	-1,554			92,951	92,951	10
	132,153	53,618			2,324,771	2,324,771	11
	1				19	19	12
	45,825	3,256			1,393,600	1,393,600	13
	2,125	5,969			-131,098	-131,098	14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administration	AD	LAS-4	NA	NA	NA
2	Western Area Power Administration	EX	262	NA	NA	NA
3	Western Area Power Administration	EX	LAS-4	NA	NA	NA
4						
5	System Deviation	NA		NA	NA	NA
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
	3,136	-5,112			234,105	234,105	1
	678						2
	8,249	104,801			-918,019	-918,019	3
							4
31,357							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
11,462,391	14,027,658	14,213,609	124,783,622	782,136,868	-450,708,841	456,211,649	

FOOTNOTE DATA

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326 Line No.: 5 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326 Line No.: 7 Column: l

Settlement adjustment.

Schedule Page: 326 Line No.: 8 Column: b

Arizona Public Service - Contract Termination Date: October 31, 2020.

Schedule Page: 326 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326 Line No.: 11 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326 Line No.: 12 Column: l

Reserve Share.

Schedule Page: 326 Line No.: 14 Column: l

Financial Swap.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.1 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.1 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.1 Line No.: 4 Column: l

Financial Swap.

Schedule Page: 326.1 Line No.: 5 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.1 Line No.: 6 Column: l

Damages for non-delivery of generation.

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

Complete name is Public Utility District No. 1 of Benton County.

Schedule Page: 326.1 Line No.: 10 Column: l

Non-generation agreement.

Schedule Page: 326.1 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.1 Line No.: 12 Column: l

Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 13 Column: l

Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.2 Line No.: 3 Column: b

Blanding City - Contract Termination Date: March 31, 2012.

Schedule Page: 326.2 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 5 Column: l

Operating reserves.

Schedule Page: 326.2 Line No.: 6 Column: b

Bonneville Power Administration - Contract Termination Date: August 31, 2011.

Schedule Page: 326.2 Line No.: 7 Column: b

Bonneville Power Administration - Contract Termination Date: 30 days written notice.

Schedule Page: 326.2 Line No.: 7 Column: l

Operating reserves.

Schedule Page: 326.2 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.2 Line No.: 8 Column: l

Operating reserves.

Schedule Page: 326.2 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 9 Column: l

Reserve Share.

Schedule Page: 326.2 Line No.: 10 Column: l

Reserve Share.

Schedule Page: 326.2 Line No.: 11 Column: b

1Settlement adjustment.

Schedule Page: 326.2 Line No.: 11 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 1 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 4 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.3 Line No.: 7 Column: a

1THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CHELAN COUNTY PUD #1" ON PAGES 326-326.24:
Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 326.3 Line No.: 7 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.3 Line No.: 8 Column: l

Reserve Share.

Schedule Page: 326.3 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 11 Column: l

Financial Swap.

Schedule Page: 326.3 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 14 Column: l

Settlement adjustment.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CONSTELLATION ENERGY COMMODITIES GROUP" ON PAGES 326-326.24:
Complete name is Constellation Energy Commodities Group, Inc.

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

Settlement adjustment.

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

Settlement adjustment.

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

Secondary, economy and/or non-firm.

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

Financial Swap.

Schedule Page: 326.4 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "COWLITZ COUNTY PUD #1" ON PAGES 326-326.24:
Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 326.4 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.4 Line No.: 9 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.4 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.4 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.4 Line No.: 11 Column: l

Financial Swap.

Schedule Page: 326.5 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 1 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 4 Column: b

Deseret Generation & Transmission - Contract Termination Date: September 30, 2024.

Schedule Page: 326.5 Line No.: 4 Column: l

Operation and maintenance expense associated with a coal fired generating facility located in Vernal, Utah.

Schedule Page: 326.5 Line No.: 5 Column: l

Financial Swap.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.5 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DOUGLAS COUNTY PUD #1" ON PAGES 326-326.24:
Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 326.5 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 8 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 9 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.5 Line No.: 10 Column: l

Operating expense, bond interest, amortization and taxes.

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

Secondary, economy and/or non-firm.

Schedule Page: 326.5 Line No.: 12 Column: l

Reserve Share.

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

Secondary, economy and/or non-firm.

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

Financial Swap.

Schedule Page: 326.6 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.6 Line No.: 6 Column: l

Line loss.

Schedule Page: 326.6 Line No.: 7 Column: l

Line loss.

Schedule Page: 326.6 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.6 Line No.: 11 Column: l

Settlement adjustment.

Schedule Page: 326.7 Line No.: 3 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.7 Line No.: 5 Column: l

Financial Swap.

Schedule Page: 326.7 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.7 Line No.: 12 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.8 Line No.: 1 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 2 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "GRANT COUNTY PUD #2" ON PAGES 326-326.24:
Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 326.8 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 2 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.8 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 3 Column: l

Ancillary services and cost recovery adjustment.

Schedule Page: 326.8 Line No.: 4 Column: b

Grant County Public Utility District No. 2 - Contract Termination Date: 2 years written notice.

Schedule Page: 326.8 Line No.: 4 Column: l

Ancillary services and cost recovery adjustment.

Schedule Page: 326.8 Line No.: 5 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.8 Line No.: 6 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.8 Line No.: 6 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.8 Line No.: 7 Column: l

Reserve Share.

Schedule Page: 326.8 Line No.: 8 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 9 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Generating Plant.

Schedule Page: 326.8 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 9 Column: l

Settlement adjustment. On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.8 Line No.: 10 Column: a

Hermiston Generating Company, L.P. operates the Hermiston Generating Plant, which is jointly owned. PacifiCorp owns 50% of the plant. See page 402.3 column (c) of this Form No. 1 for further information on the Hermiston Generating Plant.

Schedule Page: 326.8 Line No.: 10 Column: l

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.8 Line No.: 12 Column: b

Hurricane, City of - Contract Termination Date: August 31, 2012.

Schedule Page: 326.8 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.8 Line No.: 14 Column: l

Financial Swap.

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

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.9 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.9 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.9 Line No.: 3 Column: b

Secondary, economy and/or non-firm.

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

Line loss.

Schedule Page: 326.9 Line No.: 5 Column: l

Reserve Share.

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

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.9 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.9 Line No.: 10 Column: l

Financial Swap.

Schedule Page: 326.9 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "J.P. MORGAN VENTURES ENERGY CORP." ON PAGES 326-326.24:

Complete name is J.P. Morgan Ventures Energy Corporation.

Schedule Page: 326.9 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 12 Column: l

Financial Swap.

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

Complete name is JPMorgan Chase Bank, National Association.

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

Financial Swap.

Schedule Page: 326.10 Line No.: 1 Column: l

Compensation for self-generation.

Schedule Page: 326.10 Line No.: 3 Column: l

Fixed annual payment.

Schedule Page: 326.10 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "LOS ANGELES DEPT. OF WATER & POWER" ON PAGES 326-326.24:

Complete name is Los Angeles Department of Water and Power.

Schedule Page: 326.10 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 5 Column: l

Settlement adjustment.

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

Secondary, economy and/or non-firm.

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

Operating reserves.

Schedule Page: 326.10 Line No.: 7 Column: l

Line loss.

Schedule Page: 326.10 Line No.: 10 Column: l

Financial Swap.

Schedule Page: 326.10 Line No.: 12 Column: b

Magnesium Corporation of America - Contract Termination Date: December 31, 2009.

Schedule Page: 326.10 Line No.: 12 Column: l

Operating reserves.

Schedule Page: 326.11 Line No.: 4 Column: l

Compensation for interuptible service and operating reserves.

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

Under Electric Service Agreement subject to termination upon timely notification.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.11 Line No.: 8 Column: l

Financial Swap.

Schedule Page: 326.11 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 10 Column: l

Settlement adjustment.

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

Damages for non-delivery of generation.

Schedule Page: 326.11 Line No.: 13 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.11 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.11 Line No.: 14 Column: l

Line loss.

Schedule Page: 326.12 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.12 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.12 Line No.: 5 Column: l

Reserve Share.

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

Operating reserves.

Schedule Page: 326.12 Line No.: 10 Column: a

Complete name is Odell Creek Hydroelectric Investors, Ltd.

Schedule Page: 326.13 Line No.: 2 Column: a

Complete name is Pacific Northwest Generating Cooperative.

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

Settlement adjustment.

Schedule Page: 326.13 Line No.: 3 Column: l

Settlement adjustment.

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

Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 6 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 7 Column: l

Line loss.

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

Settlement adjustment.

Schedule Page: 326.13 Line No.: 8 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.13 Line No.: 9 Column: b

Portland General Electric Company - Contract Termination Date: Round Butte project no longer operating for power production purposes.

Schedule Page: 326.13 Line No.: 9 Column: l

Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.13 Line No.: 10 Column: l

Reserve Share.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.13 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.14 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.14 Line No.: 3 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUD #1 OF LEWIS COUNTY" ON PAGES 326-326.24:
Complete name is Public Utility District No.1 of Lewis County.

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

Settlement adjustment.

Schedule Page: 326.14 Line No.: 3 Column: l

Settlement adjustment.

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

Public Utility District No. 1 of Lewis County - Contract Termination Date: 60 days written notice.

FOOTNOTE DATA

Schedule Page: 326.14 Line No.: 5 Column: l
Reserve Share.

Schedule Page: 326.14 Line No.: 7 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.14 Line No.: 11 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.15 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.15 Line No.: 3 Column: b
Sacramento Municipal Utility District - Contract Termination Date: December 31, 2014.

Schedule Page: 326.15 Line No.: 4 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 4 Column: l
Operating reserves.

Schedule Page: 326.15 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.15 Line No.: 6 Column: l
Settlement adjustment.

Schedule Page: 326.15 Line No.: 7 Column: l
Line loss.

Schedule Page: 326.15 Line No.: 11 Column: l
Reserve Share.

Schedule Page: 326.15 Line No.: 13 Column: l
Financial Swap.

Schedule Page: 326.16 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.16 Line No.: 2 Column: l
Financial Swap.

Schedule Page: 326.16 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.16 Line No.: 4 Column: l
Reserve Share and Line loss.

Schedule Page: 326.16 Line No.: 7 Column: a
Complete name is Public Utiltiy District No. 1 of Snohomish County.

Schedule Page: 326.16 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 326.16 Line No.: 8 Column: l
Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.16 Line No.: 12 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.16 Line No.: 14 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.17 Line No.: 2 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.17 Line No.: 5 Column: l

Reserve Share.

Schedule Page: 326.17 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 11 Column: l

Settlement adjustment.

Schedule Page: 326.17 Line No.: 12 Column: l

Operating reserve reimbursement.

Schedule Page: 326.18 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GENERATION & TRANSMISSION" ON PAGES 326-326.24:

Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 326.18 Line No.: 1 Column: b

Tri-State Generation & Transmission - Contract Termination Date: December 31, 2020.

Schedule Page: 326.18 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 3 Column: l

Line loss.

Schedule Page: 326.18 Line No.: 4 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.18 Line No.: 5 Column: l

Line loss.

Schedule Page: 326.18 Line No.: 7 Column: l

Financial Swap.

Schedule Page: 326.18 Line No.: 8 Column: l

Financial Swap.

Schedule Page: 326.18 Line No.: 10 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UTAH ASSOC. MUNICIPAL POWER SYSTEMS" ON PAGES 326-326.24:

Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 326.18 Line No.: 11 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.19 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 6 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.19 Line No.: 7 Column: l

Reserve Share and Line loss.

Schedule Page: 326.19 Line No.: 10 Column: l

Represents the difference between actual purchase expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to account 555 during this period and excess net power cost deferrals.

Schedule Page: 326.19 Line No.: 11 Column: l

Delivery of energy to settle loss dispute.

Schedule Page: 326.19 Line No.: 12 Column: l

Recognition and reporting of gains and losses on bookouts under authoritative guidance.

Schedule Page: 326.19 Line No.: 13 Column: l

Liability associated with settlement for unmetered megawatt hours.

Schedule Page: 326.19 Line No.: 14 Column: l

Recognition and reporting of gains and losses on energy trading contracts under authoritative guidance.

Schedule Page: 326.20 Line No.: 1 Column: l

Damages associated with Naughton plant overhaul delay.

Schedule Page: 326.20 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 4 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 5 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 7 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 9 Column: l

Load factoring and storage charges.

Schedule Page: 326.20 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 10 Column: l

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.20 Line No.: 11 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 11 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 12 Column: l

Exchange energy expense and Imbalance energy.

Schedule Page: 326.20 Line No.: 13 Column: l

Load factoring and storage charges.

Schedule Page: 326.20 Line No.: 14 Column: l

Load factoring and storage charges.

Schedule Page: 326.21 Line No.: 1 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 4 Column: h

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.21 Line No.: 4 Column: i

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.21 Line No.: 4 Column: l

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.21 Line No.: 5 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 6 Column: l

Exchange energy expense and Imbalance energy.

Schedule Page: 326.21 Line No.: 8 Column: b

Not applicable: adjustment for inadvertent interchange.

Schedule Page: 326.21 Line No.: 11 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 14 Column: l

Imbalance energy.

FOOTNOTE DATA

Schedule Page: 326.22 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.22 Line No.: 1 Column: l
Load factoring and storage charges.

Schedule Page: 326.22 Line No.: 2 Column: l
Load factoring and storage charges.

Schedule Page: 326.22 Line No.: 3 Column: l
Exchange energy expense.

Schedule Page: 326.22 Line No.: 5 Column: l
Imbalance energy.

Schedule Page: 326.22 Line No.: 7 Column: l
Imbalance energy.

Schedule Page: 326.22 Line No.: 8 Column: l
Station service for third party wind project.

Schedule Page: 326.22 Line No.: 9 Column: l
Reimbursement for providing station service to third party wind project.

Schedule Page: 326.22 Line No.: 10 Column: l
Imbalance energy.

Schedule Page: 326.22 Line No.: 12 Column: l
Imbalance energy.

Schedule Page: 326.22 Line No.: 14 Column: l
Load factoring and storage charges.

Schedule Page: 326.23 Line No.: 1 Column: b
Not applicable: adjustment for inadvertent interchange.

Schedule Page: 326.23 Line No.: 2 Column: l
Exchange energy expense.

Schedule Page: 326.23 Line No.: 3 Column: l
Exchange energy expense.

Schedule Page: 326.23 Line No.: 4 Column: l
Exchange energy expense.

Schedule Page: 326.23 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 5 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 6 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 7 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 8 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 9 Column: b
Not applicable: adjustment for inadvertent interchange.

Schedule Page: 326.23 Line No.: 10 Column: b
Settlement adjustment.

Schedule Page: 326.23 Line No.: 10 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 11 Column: l
Imbalance energy.

Schedule Page: 326.23 Line No.: 12 Column: b

FOOTNOTE DATA

Settlement adjustment.

Schedule Page: 326.23 Line No.: 12 Column: l

Imbalance energy.

Schedule Page: 326.23 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.23 Line No.: 14 Column: l

Imbalance energy.

Schedule Page: 326.24 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.24 Line No.: 1 Column: l

Imbalance energy.

Schedule Page: 326.24 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.24 Line No.: 5 Column: b

Not applicable: adjustment for inadvertent interchange.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corp.	FNO
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corp.	AD
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corp.	FNO
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corp.	AD
5	Basin Electric Power Cooperative			NF
6	Bear Energy, LP			AD
7	Black Hills/Colorado Elec. Ut. Co.			SFP
8	Black Hills/Colorado Elec. Ut. Co.			NF
9	Black Hills, Inc.			NF
10	Black Hills, Inc.			AD
11	Black Hills, Inc.	PacifiCorp	Montana-Dakota Utilities Co.	FNO
12	Black Hills, Inc.	PacifiCorp	Montana-Dakota Utilities Co.	AD
13	Black Hills, Inc.	PacifiCorp	Black Hills, Inc.	LFP
14	Black Hills, Inc.	PacifiCorp	Black Hills, Inc.	AD
15	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
16	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
17	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
18	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
19	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
20	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
21	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
22	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
23	Bonneville Power Administration	Bonneville Power Administration	Umatilla Elec Coop & Columbia	FNO
24	Bonneville Power Administration	United States Bureau of Reclam.	Bonneville Power Administration	LFP
25	Bonneville Power Administration	United States Bureau of Reclam.	Bonneville Power Administration	AD
26	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
27	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
28	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
29	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
30	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
31	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
32	Bonneville Power Administration			NF
33	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
34	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-3,4	Yellowtail Sub	Sheridan Sub	22	134,691	134,691	1
7V11-3,4	Yellowtail Sub	Sheridan Sub		9,997	9,997	2
7V11	Yellowtail Sub	Sheridan Sub	11	53,955	53,955	3
7V11	Yellowtail Sub	Sheridan Sub		4,550	4,550	4
7V11-8	Various	Various		26,300	26,300	5
7V11-8	7V11-8	7V11-8				6
7V11-7	Various	Various		26	26	7
7V11-8	Various	Various		328	328	8
7V11-8	Various	Various		33,062	33,062	9
7V11-8	Various	Various		1,616	1,616	10
7V11	Various	Sheridan Sub	43	131,401	131,401	11
7V11	Various	Sheridan Sub		28,575	28,575	12
7V11-7	Various	Wyodak Sub	50	157,764	157,764	13
7V11-7	Various	Wyodak Sub		15,384	15,384	14
R.S. 237	Various	Various	310	1,432,798	1,432,798	15
R.S. 237	Various	Various		132,958	132,958	16
R.S. 324	Lost Creek Hydro Plt	Various		261,370	261,370	17
R.S. 324	Lost Creek Hydro Plt	Various		15,778	15,778	18
7V11-3,4	Bonneville Power Ad	Gazley Substation	3	23,861	23,861	19
7V11-3	Bonneville Power Ad	Gazley Substation		2,274	2,274	20
7V11-3,4	Bonneville Power Ad	Tieton Substation	2	1,829	1,829	21
7V11-3,4	Bonneville Power Ad	Tieton Substation		594	594	22
7V11-3,4	McNary Substation	Hinkle Substation	1	412	412	23
7V11-7	USBR Green Springs	Bonneville Power Adm	18	63,825	63,825	24
7V11-7	USBR Green Springs	Bonneville Power Adm		4,124	4,124	25
R.S. 368	Malin Sub	Malin Sub		612,811	612,811	26
R.S. 368	Malin Sub	Malin Sub		63,418	63,418	27
7V11-3,4	Bonneville Power Adm	White Swan/Toppenish	6	36,204	36,204	28
7V11-3,4	Bonneville Power Adm	White Swan/Toppenish		3,643	3,643	29
R.S. 299	Various	Various	217	1,349,203	1,349,203	30
R.S. 299	Various	Various		214,768	214,768	31
7V11-8	Various	Various				32
7V11-3,4	Cardwell-Merwin	Chelatchie/View	24	107,692	107,692	33
7V11-3,4	Cardwell-Merwin	Chelatchie/View		16,537	16,537	34
			1,969	**14,464,153**	**14,464,153**	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
250,418		67,221	317,639	1
		25,567	25,567	2
157,100			157,100	3
		14,620	14,620	4
	138,212		138,212	5
		6	6	6
	152		152	7
	1,997		1,997	8
	118,042		118,042	9
		10,188	10,188	10
624,376			624,376	11
		57,417	57,417	12
1,113,750			1,113,750	13
		101,250	101,250	14
3,967,708		55,593	4,023,301	15
		375,653	375,653	16
		286,253	286,253	17
		26,023	26,023	18
43,798		132,903	176,701	19
		16,005	16,005	20
27,030		676	27,706	21
		2,512	2,512	22
14,705		67	14,772	23
400,950			400,950	24
		36,450	36,450	25
		246,946	246,946	26
		22,450	22,450	27
80,824		120,735	201,559	28
		14,327	14,327	29
955,342		1,024,573	1,979,915	30
		181,871	181,871	31
	12		12	32
333,460		21,214	354,674	33
		37,511	37,511	34
25,608,245	**9,402,623**	**28,687,115**	**63,697,983**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Cargill Power Markets, LLC			NF
2	Cargill Power Markets, LLC			AD
3	Cargill Power Markets, LLC			SFP
4	CitiGroup Energy, Inc.			NF
5	Colorado Springs Utilities			NF
6	Constellation Energy Commodities Group			NF
7	Constellation Energy Commodities Group			AD
8	Constellation Energy Commodities Group			AD
9	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
10	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
11	Deseret Gen. & Trans. Coop	Deseret Gen. & Trans. Coop	Deseret Gen. & Trans. Coop	OS
12	Deseret Gen. & Trans. Coop	Deseret Gen. & Trans. Coop	Deseret Gen. & Trans. Coop	AD
13	Endure Energy, LLC			NF
14	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
15	Eugene Water & Electric Board			NF
16	Eugene Water & Electric Board			AD
17	Fall River Rural Electric Coop.	Marysville Hydro Partners	Idaho Power Company	OS
18	Fall River Rural Electric Coop.	Marysville Hydro Partners	Idaho Power Company	AD
19	Flathead Electric Coop., Inc.	Western Area Power Administration	Flathead Electric Coop., Inc.	AD
20	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	OS
21	Foote Creek III, LLC	Foote Creek III, LLC	PacifiCorp	AD
22	Gila River Power, L.P.			NF
23	Iberdrola Renewables Inc.			NF
24	Iberdrola Renewables Inc.			AD
25	Iberdrola Renewables Inc.			SFP
26	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.	OS
27	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.	AD
28	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.		OS
29	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.		AD
30	Iberdrola Renewables Inc.	Exxon Mobile Corporation	Nevada Power Company	LFP
31	Iberdrola Renewables Inc.	Exxon Mobile Corporation	Nevada Power Company	AD
32	Idaho Power Company	Nevada Power Company	Idaho Power Company	LFP
33	Idaho Power Company	Nevada Power Company	Idaho Power Company	AD
34	Idaho Power Company			SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8	Various	Various		278,389	278,389	1
7V11-8	Various	Various		31,846	31,846	2
7V11-7	Various	Various		1,200	1,200	3
7V11-8	Various	Various		148	148	4
7V11-8	Various	Various				5
	Various	Various		80,367	80,367	6
7V11-8	Various	Various		43,603	43,603	7
7V11-7	Various	Various		96	96	8
R.S. 234	Swift Unit No. 2	Woodland Sub				9
R.S. 234	Swift Unit No. 2	Woodland Sub				10
R.S. 280	Various	Various	105	1,563,223	1,563,223	11
R.S. 280	Various	Various		150,925	150,925	12
7V11-8	Various	Various		1,251	1,251	13
7V11-7	Enel Cove Fort	Mona	25			14
7V11-8	Various	Various		5,046	5,046	15
7V11-8	Various	Various		153	153	16
R.S. 322	Targhee Sub	Goshen Sub				17
R.S. 322	Targhee Sub	Goshen Sub				18
7V11-3	Yellowtail Sub	Various	2	423	423	19
S.A. 264	Foote Creek Sub	Various				20
S.A. 264	Foote Creek Sub	Various				21
7V11-8	Various	Various		379	379	22
7V11-8	Various	Various		108,915	108,915	23
7V11-8	Various	Various		12,915	12,915	24
7V11-7	Various	Various		21,366	21,366	25
7V11-5, 9	Wallula Sub	Wallula Sub				26
7V11-8	Wallula Sub	Wallula Sub				27
7V11-5, 9						28
7V11-5, 9						29
7V11-7	Exxon Metering Statn	Harry Allen/Mona Sub	30	74,272	74,272	30
7V11-7	Exxon Metering Statn	Harry Allen/Mona Sub		17,102	17,102	31
7V11-7	Red Butte	Borah/Brady	75	19,616	19,616	32
7V11-7	Red Butte	Borah/Brady				33
7V11-7	Various	Various		12,474	12,474	34
			1,969	**14,464,153**	**14,464,153**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,318,897		1,318,897	1
		272,695	272,695	2
	6,420		6,420	3
	882		882	4
	6		6	5
	388,276	81,806	470,082	6
		272,236	272,236	7
		372	372	8
		100,149	100,149	9
		9,048	9,048	10
2,206,655		1,273,687	3,480,342	11
		297,032	297,032	12
	6,331		6,331	13
		131,625	131,625	14
	30,006		30,006	15
		894	894	16
		138,699	138,699	17
		12,609	12,609	18
		3,074	3,074	19
		33,168	33,168	20
		3,015	3,015	21
	2,797		2,797	22
	1,231,492		1,231,492	23
		61,206	61,206	24
	290,229		290,229	25
		68,093	68,093	26
		7,253	7,253	27
		255,709	255,709	28
		42,144	42,144	29
1,032,750			1,032,750	30
		151,875	151,875	31
665,386			665,386	32
		-2,177	-2,177	33
	1,012,646		1,012,646	34
25,608,245	**9,402,623**	**28,687,115**	**63,697,983**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Idaho Power Company			NF
2	Idaho Power Company			AD
3	Idaho Power Company			OS
4	Idaho Power Company			AD
5	Idaho Power Company			OS
6	Idaho Power Company			AD
7	Integrys Energy Services, Inc.			NF
8	Integrys Energy Services, Inc.			AD
9	Intermountain Renewable Power LLC	Intermountain Renewable Power LLC	Intermountain Renewable Power LLC	LFP
10	JPM Ventures Energy			NF
11	Macquarie Cook Power, Inc.			NF
12	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
13	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
14	JP Morgan Ventures Energy Cooperation			NF
15	JP Morgan Ventures Energy Cooperation			AD
16	JP Morgan Ventures Energy Cooperation			SFP
17	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
18	Pacific Gas & Electric Company			OS
19	Pacific Gas & Electric Company			OS
20	Pacific Gas & Electric Company			NF
21	Portland General Electric Company			NF
22	Powerex Corporation	Bonneville Power Administration	CAISO	OS
23	Powerex Corporation	Bonneville Power Administration	CAISO	AD
24	Powerex Corporation			NF
25	Powerex Corporation			AD
26	Powerex Corporation			SFP
27	Powder River Energy Corporation			OS
28	Powder River Energy Corporation			AD
29	PPL EnergyPlus, LLC			NF
30	PPL EnergyPlus, LLC			AD
31	Public Service Co. of Colorado			SFP
32	Public Service Co. of Colorado			NF
33	Public Service Co. of Colorado			AD
34	Rainbow Energy Marketing			SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8	Various	Various		27,146	27,146	1
7V11-8	Various	Various		28	28	2
R.S. 257	Antelope Sub	Antelope Sub				3
R.S. 257	Antelope Sub	Antelope Sub				4
S.A. 203	Jim Bridger Sub	Bridger Pump Station				5
S.A. 203	Jim Bridger Sub	Bridger Pump Station				6
7V11-8	Various	Various		15	15	7
7V11-8	Various	Various		125	125	8
7V11-7, 9	Sigurd-345KV bus	Mona	11	18,414	18,414	9
7V11-8	Various	Various		50	50	10
7V11-8	Various	Various				11
R.S. 302	Duchesne	Duchesne		14,499	14,499	12
R.S. 302	Duchesne	Duchesne		1,213	1,213	13
7V11-8	Various	Various		113,276	113,276	14
7V11-8	Various	Various		6,830	6,830	15
	Various	Various				16
7V11-7, 9	Wallula Sub	Wala-Mid-C	80	800	800	17
R.S. 607	Malin Sub	Indian Springs				18
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				19
7V11-8	Various	Various		140	140	20
7V11-8	Various	Various		427	427	21
7V11-7	Bonneville Power Adm	Weed Jct. Sub	80	345,953	345,953	22
7V11-7	Bonneville Power Adm	Weed Jct. Sub		23,710	23,710	23
	Various	Various		412,139	412,139	24
7V11-8	Various	Various		25,562	25,562	25
7V11-7	Various	Various		434	434	26
R.S. 123	Various	Buffalo Sub				27
R.S. 123	Various	Buffalo Sub				28
7V11-8	Various	Various		9,044	9,044	29
7V11-8	Various	Various		554	554	30
7V11-7	Various	Various		31,600	31,600	31
7V11-8	Various	Various		2,332	2,332	32
7V11-8	Various	Various		800	800	33
7V11-7	Various	Various		35,949	35,949	34
			1,969	**14,464,153**	**14,464,153**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	156,935		156,935	1
		1,659	1,659	2
		67,672	67,672	3
		6,152	6,152	4
		14,927	14,927	5
		1,357	1,357	6
	1,343		1,343	7
		730	730	8
155,925		44,681	200,606	9
	292		292	10
	6		6	11
		18,221	18,221	12
		1,563	1,563	13
	804,598		804,598	14
		51,036	51,036	15
	619		619	16
162,000		5,806	167,806	17
		20,000,000	20,000,000	18
		327,547	327,547	19
	981		981	20
	2,756		2,756	21
1,690,875			1,690,875	22
		131,625	131,625	23
	2,244,774	32,814	2,277,588	24
		143,058	143,058	25
	2,638		2,638	26
		159	159	27
		16	16	28
	53,412		53,412	29
		3,434	3,434	30
	139,742		139,742	31
	16,282		16,282	32
		4,672	4,672	33
	115,164		115,164	34
25,608,245	**9,402,623**	**28,687,115**	**63,697,983**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Rainbow Energy Marketing			NF
2	Rainbow Energy Marketing			AD
3	Raser Power Systems LLC			SFP
4	Salt River Project			NF
5	Seattle City & Light	FPL Energy Vansycle, LLC	Grant County PUD	LFP
6	Sempra Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
7	Sempra Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
8	Shell Energy North America			NF
9	Shell Energy North America			AD
10	Sierra Pacific Power Company			NF
11	Sierra Pacific Power Company			AD
12	Sierra Pacific Power Company			SFP
13	Sierra Pacific Power Company			AD
14	Southern California Edison Company			OS
15	State of South Dakota	Western Area Power Administration	Black Hills, Inc.	LFP
16	State of South Dakota	Western Area Power Administration	Black Hills, Inc.	AD
17	TransAlta Energy Marketing Corp.			NF
18	TransAlta Energy Marketing Corp.			AD
19	Tri-State Generation & Transmission			OS
20	Tri-State Generation & Transmission			AD
21	Tri-State Generation & Transmission			NF
22	United States Bureau of Reclamation	Bonneville Power Administration	United States Bureau of Reclam.	FNO
23	United States Bureau of Reclamation	Bonneville Power Administration	United States Bureau of Reclam.	AD
24	United States Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
25	United States Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	AD
26	United States Bureau of Reclamation	Western Area Power Administration	Weber Basin	OS
27	United States Bureau of Reclamation	Western Area Power Administration	Weber Basin	AD
28	Utah Associated Municipal Power Systems	Utah Assoc. Municipal Power	Utah Assoc. Municipal Power	OS
29	Utah Associated Municipal Power Systems	Utah Assoc. Municipal Power	Utah Assoc. Municipal Power	AD
30	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
31	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
32	Warm Springs Power Enterprises	Warm Springs Enterprises	Portland General Electric Co.	OS
33	Warm Springs Power Enterprises	Warm Springs Enterprises	Portland General Electric Co.	AD
34	Western Area Power Administration	Western Area Power Administration		OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-8	Various	Various		17,671	17,671	1
7V11-8	Various	Various		10,724	10,724	2
7V11-7	Various	Various		775	775	3
7V11-7	Various	Various		15,523	15,523	4
7V11-7	Walllula Sub	Wala-Mid-C Path	25	4,379	4,379	5
7V11-3,4	Bonneville Pwr Adm	Various	15	73,958	73,958	6
7V11-3,4	Bonneville Pwr Adm	Various		8,764	8,764	7
7V11-8	Various	Various		3,979	3,979	8
7V11-8	Various	Various		134	134	9
7V11-8	Various	Various		3,539	3,539	10
7V11-8	Various	Various		850	850	11
7V11-7	Various	Various				12
7V11-7	Various	Various		53,901	53,901	13
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				14
7V11-7	Yellowtail Sub	Wyodak Sub	4	18,581	18,581	15
7V11-7	Yellowtail Sub	Wyodak Sub				16
7V11-8	Various	Various		9,226	9,226	17
7V11-8	Various	Various		4,279	4,279	18
R.S. 123	Various	Various	31	151,066	151,066	19
R.S. 123	Various	Various		16,994	16,994	20
7V11-8	Various	Various		13,148	13,148	21
7V11	Walla Walla Sub	Burbank Pumps	1	2,376	2,376	22
7V11	Walla Walla Sub	Burbank Pumps				23
R.S. 67	Redmond Substation	Crooked River Pumps		7,691	7,691	24
R.S. 67	Redmond Substation	Crooked River Pumps				25
R.S. 286	Various	Various		23,887	23,887	26
R.S. 286	Various	Various		1,300	1,300	27
R.S. 297	Various	Various	338	2,927,950	2,927,950	28
R.S. 297	Various	Various		296,627	296,627	29
R.S. 297	Various	Various	109	527,992	527,992	30
R.S. 297	Various	Various		50,002	50,002	31
R.S. 591	Pelton Reregulating	Round Butte Sub		75,382	75,382	32
R.S. 591	Pelton Reregulating	Round Butte Sub		7,355	7,355	33
	Various	Various	330	1,465,175	1,465,175	34
			1,969	**14,464,153**	**14,464,153**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	92,720		92,720	1
		60,136	60,136	2
	3,720		3,720	3
	90,654		90,654	4
50,625			50,625	5
101,960		9,805	111,765	6
		12,974	12,974	7
	28,517		28,517	8
		783	783	9
	28,751		28,751	10
		5,445	5,445	11
				12
		221,856	221,856	13
		327,547	327,547	14
89,100			89,100	15
		8,100	8,100	16
	66,418		66,418	17
		49,110	49,110	18
95,371			95,371	19
		2,663	2,663	20
	92,039		92,039	21
12,428		24,662	37,090	22
		1,730	1,730	23
		12,721	12,721	24
		531	531	25
		23,887	23,887	26
		1,300	1,300	27
6,924,597		555,240	7,479,837	28
		655,802	655,802	29
1,873,828		98,395	1,972,223	30
		176,966	176,966	31
		109,725	109,725	32
		9,975	9,975	33
2,556,785			2,556,785	34
25,608,245	**9,402,623**	**28,687,115**	**63,697,983**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Western Area Power Administration	Western Area Power Administration		AD
2	Western Area Power Administration	Western Area Power Administration		NF
3	Western Area Power Administration	Western Area Power Administration		AD
4	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
5	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD
6	Accrual True-up			
7				
8				
9				
10				
11				
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34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various		152,278	152,278	1
7V11-8	Various	Various		71,690	71,690	2
7V11-8	Various	Various				3
7V11	Wyoming Distribution	Wyoming Distribution	1	10,457	10,457	4
7V11	Wyoming Distribution	Wyoming Distribution		3	3	5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			1,969	**14,464,153**	**14,464,153**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		239,251	239,251	1
	913,865		913,865	2
		81,441	81,441	3
20,499		36,145	56,644	4
		5,058	5,058	5
		-993,505	-993,505	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
25,608,245	**9,402,623**	**28,687,115**	**63,697,983**	

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "POWDER RIVER ENERGY CORP." ON PAGES 328 – 330:
Complete name is Powder River Energy Corporation.

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

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 505), partial termination in December 2009 and January 2010.

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

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

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

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 505), partial termination in December 2009 and January 2010.

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

Distribution Service Charge. Regulation & Frequency Response. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2008 Service.

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

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 505), partial termination in December 2009 and January 2010.

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

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 228 & 505), partial termination in December 2009 and January 2010.

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

December 2008 Service. Regulation & Frequency Response.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

December 2008 Service.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BLACK HILLS/COLORADO ELEC. UT. CO." ON PAGES 328-330:
Complete name is Black Hills/Colorado Electric Utility Company, L.P.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Evergreen General Transfer Agreement for transmission service charges to various transmission and distribution delivery points.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

FOOTNOTE DATA

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

December 2008 Service.

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

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

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

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

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

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

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

Network Transmission Service under the Open Access Transmission Tariff (S.A. 347) terminating on December 31, 2017.

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

December 2008 Service.

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

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

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

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 67) terminating on December 31, 2023.

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

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

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

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 67) terminating on December 31, 2023.

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

December 2008 Service.

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

Evergreen General Transfer Agreement for transmission service charges to various transmission and distribution delivery points.

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

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328 Line No.: 16 Column: d

Evergreen General Transfer Agreement for transmission service charges to various transmission and distribution delivery points.

Schedule Page: 328 Line No.: 16 Column: m

December 2008 Service.

Schedule Page: 328 Line No.: 17 Column: d

Legacy use of facilities as defined in the contract. Terminating October 2010.

Schedule Page: 328 Line No.: 17 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 56 MW.

Schedule Page: 328 Line No.: 18 Column: d

Legacy use of facilities as defined in the contract. Terminating October 2010.

Schedule Page: 328 Line No.: 18 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 56 MW.

Schedule Page: 328 Line No.: 19 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 229) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 19 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response.

Schedule Page: 328 Line No.: 20 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 229) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 20 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2008 Service.

Schedule Page: 328 Line No.: 21 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BENTON REA" ON PAGES 328 – 330:
Complete name is Benton Rural Electric Association.

Schedule Page: 328 Line No.: 21 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 21 Column: m

Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 22 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 22 Column: m

December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 23 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UMATILLA ELEC COOP & COLUMBIA" ON PAGES 328 – 330:
Complete names are Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative Inc.

Schedule Page: 328 Line No.: 23 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 23 Column: m

Regulation & Frequency Response.

Schedule Page: 328 Line No.: 24 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UNITED STATES BUREAU OF RECLAM." and "UNITED STATES BUREAU OF RECLAMATION" ON PAGES 328 – 330:
Complete name is United States Department of the Interior, Bureau of Reclamation.

Schedule Page: 328 Line No.: 24 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 25 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 25 Column: m

December 2008 Service.

Schedule Page: 328 Line No.: 26 Column: d

Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with Bonneville Power Administration. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 26 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 110 MW.

Schedule Page: 328 Line No.: 27 Column: d

Use of Facilities Agreement for the Malin Transformer under the AC Intertie Agreement with Bonneville Power Administration dated

June 1, 1994. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 27 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 110 MW.

Schedule Page: 328 Line No.: 28 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 28 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 29 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 328) terminating on September 30, 2011.

Schedule Page: 328 Line No.: 29 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 30 Column: d

Evergreen General Transfer Agreement for transmission service to various transmission and distribution delivery points.

Schedule Page: 328 Line No.: 30 Column: m

Sole use of facilities/direct assigned facilities charge. Charges for monitoring, scheduling, load following and spinning reserve.

Schedule Page: 328 Line No.: 31 Column: d

Evergreen General Transfer Agreement for transmission service to various transmission and distribution delivery points.

Schedule Page: 328 Line No.: 31 Column: m

Sole use of facilities/direct assigned facilities charge. Charges for monitoring, scheduling, load following and spinning reserve. December 2008 Service.

Schedule Page: 328 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 32 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 33 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 370) terminating on December 7, 2012 or with 6 month written notice.

Schedule Page: 328 Line No.: 33 Column: m

Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 34 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 370) terminating on December 7, 2012 or with 6 month written notice.

Schedule Page: 328 Line No.: 34 Column: m

Regulation & Frequency Response. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 2 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 2 Column: m

December 2008 Service.

Schedule Page: 328.1 Line No.: 3 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 4 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 4 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 4 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 5 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 6 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CONSTELLATION ENERGY COMMODITIES GROUP" ON PAGES 328 – 330:
Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 328.1 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 6 Column: e

7V11-5, 8, 9, 11

Schedule Page: 328.1 Line No.: 6 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 7 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 8 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 8 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 8 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 8 Column: m

December 2008 Service.

Schedule Page: 328.1 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "COWLITZ COUNTY PUD" ON PAGES 328 – 330:
Complete name is Public Utility District No.1 of Cowlitz County.

Schedule Page: 328.1 Line No.: 9 Column: d

Agreement providing for transmission and operation of Cowlitz's Swift 2 Hydro Generation. Payment is for 26% of annual costs of Swift-Cowlitz Transmission Line. Agreement is for the life of Swift Unit No. 2.

Schedule Page: 328.1 Line No.: 9 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 82 MW.

Schedule Page: 328.1 Line No.: 10 Column: d

Agreement providing for transmission and operation of Cowlitz's Swift 2 Hydro Generation. Payment is for 26% of annual costs of Swift-Cowlitz Transmission Line. Agreement is for the life of Swift Unit No. 2.

Schedule Page: 328.1 Line No.: 10 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 82 MW.

Schedule Page: 328.1 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET GEN. & TRANS. COOP" ON PAGES 328 – 330:
Complete name is Deseret Generation and Transmission Cooperative.

Schedule Page: 328.1 Line No.: 11 Column: d

Legacy Transmission Service Operating Agreement and Control Area Services Agreement for transmission services. Transmission Service Operating Agreement - termination upon mutual agreement. Control Area Services Agreement - termination upon two years written notice by either party.

Schedule Page: 328.1 Line No.: 11 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Regulation & Frequency Response. Meter Interrogation Services.

Schedule Page: 328.1 Line No.: 12 Column: d

Legacy Transmission Service Operating Agreement and Control Area Services Agreement for transmission services. Transmission Service Operating Agreement - termination upon mutual agreement. Control Area Services Agreement - termination upon two years written notice by either party.

Schedule Page: 328.1 Line No.: 12 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Regulation & Frequency Response. Meter Interrogation Services. December 2008 Service.

Schedule Page: 328.1 Line No.: 13 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 13 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 13 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 14 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 14 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 426) deferred until November 1, 2010 - terminating April 30, 2042.

Schedule Page: 328.1 Line No.: 14 Column: m

Extension of Commencement Date Fee.

Schedule Page: 328.1 Line No.: 15 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 15 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 16 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 16 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 16 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 16 Column: m

December 2008 Service.

Schedule Page: 328.1 Line No.: 17 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "FALL RIVER RURAL ELECTRIC COOP." ON PAGES 328 – 330:
Complete name is Fall River Rural Electric Cooperative.

Schedule Page: 328.1 Line No.: 17 Column: d

Legacy use of facilities as defined in the contract. Terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 17 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 9 MW.

Schedule Page: 328.1 Line No.: 18 Column: d

Legacy use of facilities as defined in the contract. Terminating on July 31, 2028.

Schedule Page: 328.1 Line No.: 18 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 9 MW.

Schedule Page: 328.1 Line No.: 19 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "FLATHEAD ELECTRIC COOP., INC." ON PAGES 328 – 330:
Complete name is Flathead Electric Cooperative, Inc.

Schedule Page: 328.1 Line No.: 19 Column: d

Network integration transmission service terminated and service is being covered through a Basin Electric Power Cooperative's transmission service agreement.

Schedule Page: 328.1 Line No.: 19 Column: m

Distribution Service Charge. Primary Delivery Service. Regulation & Frequency Response. December 2008 Service.

Schedule Page: 328.1 Line No.: 20 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 20 Column: d

Direct Assignment Facilities Service Agreement (S.A. 264) for point-to-point transmission at 34.5kv. Terminating July 2014.

Schedule Page: 328.1 Line No.: 20 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 21 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 21 Column: d

Direct Assignment Facilities Service Agreement (S.A. 264) for point-to-point transmission at 34.5kv. Terminating July 2014.

Schedule Page: 328.1 Line No.: 21 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 22 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 22 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 23 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

FOOTNOTE DATA

Schedule Page: 328.1 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 24 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 24 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 24 Column: m

December 2008 Service.

Schedule Page: 328.1 Line No.: 25 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 25 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 26 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 313) in effect until superceded.

Schedule Page: 328.1 Line No.: 26 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 27 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 27 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 28 Column: c

Iberdrola Renewables Inc. and Utah Associated Municipal Power Systems.

Schedule Page: 328.1 Line No.: 28 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

Schedule Page: 328.1 Line No.: 28 Column: f

Long Hollow, WY switching station.

Schedule Page: 328.1 Line No.: 28 Column: g

Long Hollow, WY switching station.

Schedule Page: 328.1 Line No.: 28 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 29 Column: c

Iberdrola Renewables Inc. and Utah Associated Municipal Power Systems.

Schedule Page: 328.1 Line No.: 29 Column: d

Ancillary Services under the Open Access Transmission Tariff (S.A. 315) in effect until superceded.

Schedule Page: 328.1 Line No.: 29 Column: f

Long Hollow, WY switching station.

Schedule Page: 328.1 Line No.: 29 Column: g

Long Hollow, WY switching station.

Schedule Page: 328.1 Line No.: 29 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Unauthorized Use of Transmission Service. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 30 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2014.

Schedule Page: 328.1 Line No.: 31 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 279). Terminates April 30, 2014.

Schedule Page: 328.1 Line No.: 31 Column: m

December 2008 Service.

Schedule Page: 328.1 Line No.: 32 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212) terminating May 31, 2014.

Schedule Page: 328.1 Line No.: 33 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 212) terminating May 31, 2014.

Schedule Page: 328.1 Line No.: 33 Column: m

Capacity reassignment refund for October 2008. December 2008 Service.

Schedule Page: 328.1 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 2 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 2 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 2 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 2 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 3 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 3 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 3 Column: d

Use of Facilities Agreement - Antelope Substation (R.S. 257) terminating coterminous with the Idaho/USDOE Supply Agreement.

Schedule Page: 328.2 Line No.: 3 Column: m

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328.2 Line No.: 4 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 4 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 4 Column: d

Use of Facilities Agreement - Antelope Substation (R.S. 257) terminating coterminous with the Idaho/USDOE Supply Agreement.

Schedule Page: 328.2 Line No.: 4 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 5 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 5 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

FOOTNOTE DATA

Schedule Page: 328.2 Line No.: 5 Column: d

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

Schedule Page: 328.2 Line No.: 5 Column: m

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328.2 Line No.: 6 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: d

Use of Facilities Agreement - Jim Bridger Pump (S.A. 203) - termination upon 12-month written notice.

Schedule Page: 328.2 Line No.: 6 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 7 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 7 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 8 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 8 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 8 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 9 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 509) terminating April 30, 2029.

Schedule Page: 328.2 Line No.: 9 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 11 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 12 Column: d

Legacy Transmission Service and Interconnection Agreement for use of facilities. Terminates in 2047.

Schedule Page: 328.2 Line No.: 12 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 2.5 MW.

Schedule Page: 328.2 Line No.: 13 Column: d

Legacy Transmission Service and Interconnection Agreement for use of facilities. Terminates in 2047.

Schedule Page: 328.2 Line No.: 13 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 2.5 MW.

Schedule Page: 328.2 Line No.: 14 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 15 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 16 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 16 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 16 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 16 Column: e

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Schedule Page: 328.2 Line No.: 17 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "GRANT COUNTY PUD" ON PAGES 328 – 330:
Complete name is Grant County Public Utility District.

Schedule Page: 328.2 Line No.: 17 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (S.A. 626), assignment from Seattle City & Light, terminating December 31, 2011.

Schedule Page: 328.2 Line No.: 17 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 18 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 18 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 18 Column: d

Malin to Round Mountain facilities lease (R.S. 607). Terminating December 31, 2017.

Schedule Page: 328.2 Line No.: 18 Column: m

Sole use of facilities. Total capacity of the line is 800 MW north to south and 612.5 MW south to north.

Schedule Page: 328.2 Line No.: 19 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 19 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 19 Column: d

Use of Facilities Agreement - Phase Shifting Transformers at Sigurd-Glen Canyon 230kv transmission line and Pinto-Four Corners 345kv transmission line (S.A. 298), terminating February 12, 2020.

Schedule Page: 328.2 Line No.: 19 Column: m

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328.2 Line No.: 20 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 20 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 20 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 22 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CASIO" ON PAGES 328 – 330:
Complete name is California ISO.

Schedule Page: 328.2 Line No.: 22 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169) terminating on September 30, 2012.

Schedule Page: 328.2 Line No.: 23 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 169) terminating on September 30, 2012.

Schedule Page: 328.2 Line No.: 23 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 24 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 24 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 24 Column: e

7V11-5, 8, 9

Schedule Page: 328.2 Line No.: 24 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 25 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 25 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 26 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 27 Column: b

Various Western Association Power Administration Interconnection in PACE

Schedule Page: 328.2 Line No.: 27 Column: c

Sheridan-Johnson Rural Electrification Association

Schedule Page: 328.2 Line No.: 27 Column: d

Legacy Transmission Service Agreement (R.S. 123). Terminating October 1, 2014.

FOOTNOTE DATA

Schedule Page: 328.2 Line No.: 27 Column: m

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328.2 Line No.: 28 Column: b

Various Western Association Power Administration Interconnection in PACE

Schedule Page: 328.2 Line No.: 28 Column: c

Sheridan Johnson Rural Electrification Association

Schedule Page: 328.2 Line No.: 28 Column: d

Legacy Transmission Service Agreement (R.S. 123). Terminating October 1, 2014.

Schedule Page: 328.2 Line No.: 28 Column: m

Sole use of facilities/direct assigned facilities charge. December 2008 Service.

Schedule Page: 328.2 Line No.: 29 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 30 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 30 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 31 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SERVICE CO. OF COLORADO" ON PAGES 328 – 330:
Complete name is Public Service Company of Colorado.

Schedule Page: 328.2 Line No.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 31 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 32 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 33 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 33 Column: m

December 2008 Service.

Schedule Page: 328.2 Line No.: 34 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "RAINBOW ENERGY MARKETING" ON PAGES 328 – 330:
Complete name is Rainbow Energy Marketing Corporation.

Schedule Page: 328.2 Line No.: 34 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 34 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 1 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 1 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 2 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 2 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 2 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 2 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 3 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 3 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 3 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 4 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 4 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 4 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 5 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff, (7th revised S.A. 289) terminating October 31, 2014.

Schedule Page: 328.3 Line No.: 6 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 299). Service provided pursuant to rules and regulations of Oregon Direct Access. Termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: f

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BONNEVILLE PWR ADM." ON PAGES 328-330: Complete name is Bonneville Power Administration.

Schedule Page: 328.3 Line No.: 6 Column: m

Regulation & Frequency Response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.3 Line No.: 7 Column: d

Network Transmission Service under the Open Access Transmission Tariff (S.A. 299). Service provided pursuant to rules & regulations of Oregon Direct Access. Termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.3 Line No.: 7 Column: m

Regulation & Frequency Response. December 2008 Service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.3 Line No.: 8 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

FOOTNOTE DATA

Schedule Page: 328.3 Line No.: 8 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 8 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 9 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 9 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 12 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 12 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 12 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 13 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 13 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 13 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 13 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 14 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 14 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 14 Column: d

Use of Facilities Agreement - Phase Shifting Transformers at Sigurd-Glen Canyon 230kv transmission line and Pinto-Four Corners 345kv transmission line (S.A. 298), terminating February 12, 2020.

Schedule Page: 328.3 Line No.: 14 Column: m

Sole use of facilities/direct assigned facilities charge.

Schedule Page: 328.3 Line No.: 15 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2014.

FOOTNOTE DATA

Schedule Page: 328.3 Line No.: 16 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 170) terminating on May 31, 2014.

Schedule Page: 328.3 Line No.: 16 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 17 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 17 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 17 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 18 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 18 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 18 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 18 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 19 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GENERATION & TRANSMISSION" ON PAGES 328 – 330:

Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 328.3 Line No.: 19 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 19 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 19 Column: d

Legacy Transmission Service Agreement (R.S. 123). Terminating October 1, 2014.

Schedule Page: 328.3 Line No.: 20 Column: b

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 Column: c

Operation, maintenance and facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 Column: d

Legacy Transmission Service Agreement (R.S. 123). Terminating October 1, 2014.

Schedule Page: 328.3 Line No.: 20 Column: m

December 2008 Service.

Schedule Page: 328.3 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 21 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 22 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 506).Termination upon written notification.

Schedule Page: 328.3 Line No.: 22 Column: m

Distribution Service Charge. Primary Delivery Service.

Schedule Page: 328.3 Line No.: 23 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (S.A. 506). Termination upon written notification.

Schedule Page: 328.3 Line No.: 23 Column: m

2008 primary delivery and distribution adjustments. December 2008 Service.

Schedule Page: 328.3 Line No.: 24 Column: d

Legacy agreement For Use Of Facilities For the Transmission of Electrical Power and Energy (R.S. 67). Termination upon one year written notice.

Schedule Page: 328.3 Line No.: 24 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328.3 Line No.: 25 Column: d

Legacy agreement For Use Of Facilities For the Transmission of Electrical Power and Energy (R.S. 67). Terminating with one year written notice.

Schedule Page: 328.3 Line No.: 25 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract.

Schedule Page: 328.3 Line No.: 26 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WEBER BASIN" ON PAGES 328 – 330:
Complete name is Weber Basin Water Conservancy District.

Schedule Page: 328.3 Line No.: 26 Column: d

Legacy Water Exchange and Transmission Service Agreement (R. S. 286) for energy deliveries at and below 138kv. Terminating any time after April 1, 2040 with four years written notification.

Schedule Page: 328.3 Line No.: 26 Column: m

Energy consumption charge for deliveries at and below 138kv.

Schedule Page: 328.3 Line No.: 27 Column: d

Legacy Water Exchange and Transmission Service Agreement (R. S. 286) for energy deliveries at and below 138kv. Terminating any time after April 1, 2040 with four years written notification.

Schedule Page: 328.3 Line No.: 27 Column: m

December 2008 Service. Energy consumption charge for deliveries at and below 138kv.

Schedule Page: 328.3 Line No.: 28 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UTAH ASSOC. MUNICIPAL POWER" ON PAGES 328 – 330:
Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 328.3 Line No.: 28 Column: d

Legacy Amended and Restated Transmission Service and Operating Agreement (R.S. 297) for transmission services. Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.3 Line No.: 28 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. Unauthorized Use of Transmission Service.

Schedule Page: 328.3 Line No.: 29 Column: d

Legacy Amended and Restated Transmission Service and Operating Agreement (R.S. 297) for transmission services. Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.3 Line No.: 29 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. Distribution Service Charge. December 2008 Service.

Schedule Page: 328.3 Line No.: 30 Column: d

Legacy 2nd Amended Transmission Service and Operating Agreement for transmission services (R.S. 279). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.3 Line No.: 30 Column: m

Charges for monitoring, scheduling, load following and spinning reserve.

Schedule Page: 328.3 Line No.: 31 Column: d

Legacy 2nd Amended Transmission Service and Operating Agreement for transmission services (R.S. 279). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.3 Line No.: 31 Column: m

Charges for monitoring, scheduling, load following and spinning reserve. December 2008 Service.

Schedule Page: 328.3 Line No.: 32 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PORTLAND GENERAL ELECTRIC CO." ON PAGES 328 – 330:
Complete name is Portland General Electric Company.

Schedule Page: 328.3 Line No.: 32 Column: d

Evergreen General Transfer Agreement for transmission service charges to various transmission and distribution delivery points.

Schedule Page: 328.3 Line No.: 32 Column: m

Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 16 MW.

Schedule Page: 328.3 Line No.: 33 Column: d

Transmission Service Agreement (R.S. 591) terminating January 1, 2032.

Schedule Page: 328.3 Line No.: 33 Column: m

December 2008 Service. Sole use of facilities charge based on a capacity factor and or proportional use as defined in the contract. Customer capacity is 16 MW.

Schedule Page: 328.3 Line No.: 34 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.3 Line No.: 34 Column: d

Transmission Interconnection and Transmission Service Agreement (R.S. 262) for transmission service to preferential customers and Low Voltage Transmission Service (R.S. 263) for deliveries of Colorado River Storage Project power and energy to certain municipalities at service below 138kv. Terminating after three years written notice and mutual consent.

Schedule Page: 328.3 Line No.: 34 Column: e

R.S. 262 & 263

Schedule Page: 328.4 Line No.: 1 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.4 Line No.: 1 Column: d

Transmission Interconnection and Transmission Service Agreement (R.S. 262) for transmission service to preferential customers and Low Voltage Transmission Service (R.S. 263) for deliveries of Colorado River Storage Project power and energy to certain municipalities at service below 138kv. Terminating after three years written notice and mutual consent.

Schedule Page: 328.4 Line No.: 1 Column: e

R.S. 262 & 263

Schedule Page: 328.4 Line No.: 1 Column: m

December 2008 Service.

Schedule Page: 328.4 Line No.: 2 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 2 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 3 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 3 Column: d

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 3 Column: m

December 2008 Service.

Schedule Page: 328.4 Line No.: 4 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

Schedule Page: 328.4 Line No.: 4 Column: m

Distribution Service Charge. Primary Delivery Service.

Schedule Page: 328.4 Line No.: 5 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (S.A. 175).

Schedule Page: 328.4 Line No.: 5 Column: m

Distribution Service Charge. Primary Delivery Service. December 2008 Service.

Schedule Page: 328.4 Line No.: 6 Column: m

Represents the difference between actual wheeling revenues for the period as reflected on the individual line items within this schedule, and the accruals credited to account 456.1 during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Srv. Co.	LFP	222,069	222,069	1,087,640			1,087,640
2	Arizona Public Srv. Co.	NF	9,234	9,234	35,622			35,622
3	Arizona Public Srv. Co.	OS					3,928	3,928
4	Arizona Public Srv. Co.	SFP	30,981	30,981	128,617			128,617
5	Ashland, City of	FNS	1,845	1,845		17,747		17,747
6	Avista Corporation	AD	-600	-600	-1,600			-1,600
7	Avista Corporation	FNS	52,108	53,856	206,460			206,460
8	Avista Corporation	NF	20,931	20,931	82,824			82,824
9	Avista Corporation	SFP	5,520	5,520	14,858			14,858
10	Big Horn Rural Electric	OS					130,848	130,848
11	Bonneville Power Admin.	AD	38,557	38,557	33,769	167,130	-28,319	172,580
12	Bonneville Power Admin.	FNS			1,964,012		1,806	1,965,818
13	Bonneville Power Admin.	LFP	5,621,547	5,621,547	45,415,944		1,943,055	47,358,999
14	Bonneville Power Admin.	NF	96,834	96,834	153,530	419,293		572,823
15	Bonneville Power Admin.	OS	5,505,499	5,724,708	34,799,705	145,402	2,455,408	37,400,515
16	Bonneville Power Admin.	SFP	29,976	29,976	76,935	59,418		136,353
	TOTAL		16,060,965	16,355,485	98,453,642	2,999,973	15,707,595	117,161,210

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	CA Ind. Sys. Operator	AD				-11,568	572,874	561,306
2	CA Ind. Sys. Operator	OS					1,984,953	1,984,953
3	CA Ind. Sys. Operator	SFP	557,341	557,341		2,179,960		2,179,960
4	Deseret Pwr Elect. Coop	AD	-3,600	-3,600	-2,500			-2,500
5	Deseret Pwr Elect. Coop	LFP	171,563	171,563	2,763,692			2,763,692
6	El Paso Elect. Co.	AD	-9,200	-9,200	-20,500			-20,500
7	El Paso Elect. Co.	SFP	738	738	1,922			1,922
8	Flathead Elect. Coop.	AD					-696	-696
9	Flathead Elect. Coop.	OS					59,798	59,798
10	Hermiston Gen Co., L.P.	OS					176,594	176,594
11	Idaho Power Company	AD			-1,674,370		-10,348	-1,684,718
12	Idaho Power Company	FNS			6,426			6,426
13	Idaho Power Company	LFP	1,862,573	1,862,573	3,128,654			3,128,654
14	Idaho Power Company	NF	402,653	458,800	1,063,723	11,591		1,075,314
15	Idaho Power Company	OS					9,132,976	9,132,976
16	Idaho Power Company	SFP	135,995	135,995	244,395			244,395
	TOTAL		16,060,965	16,355,485	98,453,642	2,999,973	15,707,595	117,161,210

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Los Ang. Dept Water/Pwr	OS					886	886
2	Los Ang. Dept Water/Pwr	SFP	2,149	2,149	19,341			19,341
3	MAPPCOR	OS					-2,424	-2,424
4	Moon Lake Elect. Assoc.	AD					41,552	41,552
5	Moon Lake Elect. Assoc.	FNS					126,059	126,059
6	Nevada Power Company	AD	-832	-832				
7	Nevada Power Company	NF	46,157	46,157	137,375			137,375
8	Nevada Power Company	OS					57,900	57,900
9	Nevada Power Company	SFP	61,792	61,792	184,342			184,342
10	NorthWestern Corp.	NF	158,532	163,744	704,161			704,161
11	NorthWestern Corp.	OS					38,422	38,422
12	NorthWestern Corp.	SFP	4,152	4,152	17,975			17,975
13	Platte River Power	LFP	171,563	171,563	966,000			966,000
14	Platte River Power	OS					14,882	14,882
15	Portland Gen. Electric	OS					1,064	1,064
16	Portland Gen. Electric	SFP			-828,000			-828,000
	TOTAL		16,060,965	16,355,485	98,453,642	2,999,973	15,707,595	117,161,210

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Powerex	SFP			-325,000			-325,000
2	Public Service Co of CO	LFP	119,844	125,943	884,178			884,178
3	Public Service Co of NM	LFP	117,107	117,107	589,415			589,415
4	Public Service Co of NM	NF	569	569	1,616			1,616
5	Public Service Co of NM	OS					21,275	21,275
6	Public Service Co of NM	SFP	806	806	2,289			2,289
7	Salt River Project	NF	250	250	709			709
8	Sierra Pacific Power Co	AD	-5,800	-5,800	-40,616		-6,510	-47,126
9	Sierra Pacific Power Co	NF	13,507	13,507	83,281			83,281
10	Sierra Pacific Power Co	OS					15,851	15,851
11	Sierra Pacific Power Co	SFP	3,833	3,833	17,472			17,472
12	Surprise Valley Electr	OS					9,336	9,336
13	TransAlta Engy Mkt Inc.	SFP			-782,000			-782,000
14	Tri-State Gen & Transm	LFP	125,224	131,329	884,178			884,178
15	Tri-State Gen & Transm	NF	15,616	15,616	44,049			44,049
16	Tri-State Gen & Transm	OS					21,083	21,083
	TOTAL		16,060,965	16,355,485	98,453,642	2,999,973	15,707,595	117,161,210

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Tucson Electric Power	NF	1,964	1,964	6,088			6,088
2	Tucson Electric Power	OS					1,174	1,174
3	Tucson Electric Power	SFP	50	50	155			155
4	Utah Assoc Muni Pwr Sys	AD					-296	-296
5	Utah Assoc Muni Pwr Sys	LFP	242,235	242,235	1,293,600			1,293,600
6	Utah Assoc Muni Pwr Sys	OS					7,000	7,000
7	Utah Assoc Muni Pwr Sys	SFP					15,910	15,910
8	Wesport Field Srv LLC	LFP			-1,682,919			-1,682,919
9	Western Area Power Adm.	AD			7,331		1,189	8,520
10	Western Area Power Adm.	FNS			4,465,373			4,465,373
11	Western Area Power Adm.	LFP	215,182	215,182	2,250,000			2,250,000
12	Western Area Power Adm.	NF	7,599	7,599	16,353			16,353
13	Western Area Power Adm.	OS				11,000	380,037	391,037
14	Western Area Power Adm.	SFP	6,902	6,902	27,138			27,138
15	Accrual True-up						-1,459,672	-1,459,672
16								
	TOTAL		16,060,965	16,355,485	98,453,642	2,999,973	15,707,595	117,161,210

Schedule Page: 332 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "ARIZONA PUBLIC SRV. CO." ON PAGE 332:
Complete name is Arizona Public Service Company

Schedule Page: 332 Line No.: 1 Column: b

Arizona Public Service Co. - Contract Termination Dates: May 1, 2013, August 31, 2013, January 11, 2041 and May 31, 2047.

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

Ancillary Services.

Schedule Page: 332 Line No.: 6 Column: b

Settlement Adjustment.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BIG HORN RURAL ELECTRIC"
ON PAGE 332:

Complete name is Big Horn Rural Electric Cooperative.

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

Use of Facilities.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BONNEVILLE POWER ADMIN."
ON PAGE 332:

Complete name is Bonneville Power Administration.

Schedule Page: 332 Line No.: 11 Column: b

Settlement Adjustment.

Schedule Page: 332 Line No.: 11 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332 Line No.: 12 Column: g

Use of Facilities.

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

Bonneville Power Administration - Contract Termination Dates: July 1, 2009, October 1, 2009, January 1, 2010, January 1, 2011, July 1, 2011, September 1, 2011, December 1, 2011, April 1, 2012, July 1, 2012, November 1, 2012, July 1, 2013, September 1, 2013, October 1, 2013, December 1, 2013, January 1, 2014, October 1, 2027, November 1, 2033 and evergreen.

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

Ancillary Services.

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

Ancillary Services. Use of Facilities.

Schedule Page: 332.1 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CA IND. SYS. OPERATOR"
ON PAGE 332.1:

Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 1 Column: b

Settlement Adjustment.

Schedule Page: 332.1 Line No.: 1 Column: g

Ancillary Services.

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

Ancillary Services.

Schedule Page: 332.1 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET PWR ELECT. COOP"

ON PAGE 332.1:
Complete name is Deseret Power Electric Cooperative.

Schedule Page: 332.1 Line No.: 4 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 5 Column: b
Deseret Generation & Transmission - Contract Termination Dates: October 31, 2012, September 1, 2018.

Schedule Page: 332.1 Line No.: 6 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "EL PASO ELECT. CO."
ON PAGE 332.1:
Complete name is El Paso Electric Company.

Schedule Page: 332.1 Line No.: 6 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 8 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "FLATHEAD ELECT. COOP."
ON PAGE 332.1:
Complete name is Flathead Electric Cooperative.

Schedule Page: 332.1 Line No.: 8 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 8 Column: g
Use of Facilities.

Schedule Page: 332.1 Line No.: 9 Column: g
Use of Facilities.

Schedule Page: 332.1 Line No.: 10 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "HERMISTON GEN CO., L.P."
ON PAGE 332.1:
Complete name is Hermiston Generating Company, L.P.

Schedule Page: 332.1 Line No.: 10 Column: g
Use of Facilities.

Schedule Page: 332.1 Line No.: 11 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 11 Column: g
Respondent's portion of specified costs of certain facilities.

Schedule Page: 332.1 Line No.: 13 Column: b
Idaho Power Company - Contract Termination Dates: June 13, 2009, April 1, 2011.

Schedule Page: 332.1 Line No.: 15 Column: g
Ancillary Services. Use of Facilities. Respondent's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 1 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "LOS ANG. DEPT WATER/PWR"
ON PAGE 332.2:
Complete name is Los Angeles Department of Water and Power.

Schedule Page: 332.2 Line No.: 1 Column: g
Ancillary Services.

Schedule Page: 332.2 Line No.: 3 Column: g
Patronage refund.

Schedule Page: 332.2 Line No.: 4 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "MOON LAKE ELECT. ASSOC."

ON PAGE 332.2:
Complete name is Moon Lake Electric Association.

Schedule Page: 332.2 Line No.: 4 Column: b
Settlement Adjustment.

Schedule Page: 332.2 Line No.: 4 Column: g
Use of Facilities.

Schedule Page: 332.2 Line No.: 5 Column: g
Use of Facilities.

Schedule Page: 332.2 Line No.: 6 Column: b
Settlement Adjustment.

Schedule Page: 332.2 Line No.: 8 Column: g
Ancillary Services.

Schedule Page: 332.2 Line No.: 10 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "NORTHWESTERN CORP." ON PAGE 332.2:
Complete name is NorthWestern Corporation.

Schedule Page: 332.2 Line No.: 11 Column: g
Ancillary Services.

Schedule Page: 332.2 Line No.: 13 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PLATT RIVER POWER" ON PAGE 332.2:
Complete name is Platt River Power Authority.

Schedule Page: 332.2 Line No.: 13 Column: b
Platte River Power Authority - Contract Termination Date: October 31, 2012.

Schedule Page: 332.2 Line No.: 14 Column: g
Ancillary Services.

Schedule Page: 332.2 Line No.: 15 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PORTLAND GEN. ELECTRIC"
ON PAGE 332.2:
Complete name is Portland General Electric Company.

Schedule Page: 332.2 Line No.: 15 Column: g
Use of Facilities.

Schedule Page: 332.2 Line No.: 16 Column: e
Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 1 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "POWEREX" ON PAGE 332.3:
Complete name is Powerex Corporation.

Schedule Page: 332.3 Line No.: 1 Column: e
Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 2 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SERVICE CO OF CO"
ON PAGE 332.3:
Complete name is Public Service Company of Colorado.

Schedule Page: 332.3 Line No.: 2 Column: b
Public Service Company of Colorado - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 3 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SERVICE CO OF NM" ON PAGE 332.3:
Complete name is Public Service Company of New Mexico.

Schedule Page: 332.3 Line No.: 3 Column: b
Public Service Company of New Mexico - Contract Termination Date: December 1, 2012.

Schedule Page: 332.3 Line No.: 5 Column: g
Ancillary Services.

Schedule Page: 332.3 Line No.: 8 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SIERRA PACIFIC POWER CO" ON PAGE 332.3:
Complete name is Sierra Pacific Power Company.

Schedule Page: 332.3 Line No.: 8 Column: b
Settlement Adjustment.

Schedule Page: 332.3 Line No.: 8 Column: g
Ancillary Services.

Schedule Page: 332.3 Line No.: 10 Column: g
Ancillary Services.

Schedule Page: 332.3 Line No.: 12 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SURPRISE VALLEY ELECTR." ON PAGE 332.3:
Complete name is Surprise Valley Electrification Corp.

Schedule Page: 332.3 Line No.: 12 Column: g
Use of Facilities.

Schedule Page: 332.3 Line No.: 13 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRANSALTA ENGY MKT INC." ON PAGE 332.3:
Complete name is TransAlta Energy Marketing Inc.

Schedule Page: 332.3 Line No.: 13 Column: e
Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 14 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GEN & TRANSM" ON PAGE 332.3:
Complete name is Tri-State Generation & Transmission Association, Inc.

Schedule Page: 332.3 Line No.: 14 Column: b
Tri-State Generation & Transmission - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 16 Column: g
Ancillary Services.

Schedule Page: 332.4 Line No.: 1 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TUCSON ELECTRIC POWER" ON PAGE 332.4:
Complete name is Tucson Electric Power Company.

Schedule Page: 332.4 Line No.: 2 Column: g
Ancillary Services.

Schedule Page: 332.4 Line No.: 4 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UTAH ASSOC MUNI PWR SYS" ON PAGE 332.4:

Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 332.4 Line No.: 4 Column: b

Settlement Adjustment.

Schedule Page: 332.4 Line No.: 4 Column: g

Ancillary Services.

Schedule Page: 332.4 Line No.: 5 Column: b

Utah Associated Municipal Power Systems - Contract Termination Date: November 30, 2009.

Schedule Page: 332.4 Line No.: 6 Column: g

Use of Facilities.

Schedule Page: 332.4 Line No.: 7 Column: g

Ancillary Services.

Schedule Page: 332.4 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WESPORT FIELD SRV LLC"
ON PAGE 332.4:

Complete name is Wesport Field Services, LLC.

Schedule Page: 332.4 Line No.: 8 Column: b

Westport Field Services, LLC - Contract Termination Date: Evergreen.

Schedule Page: 332.4 Line No.: 8 Column: e

Reimbursement for providing third party service.

Schedule Page: 332.4 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WESTERN AREA POWER ADM."
ON PAGE 332.4:

Complete name is Western Area Power Administration.

Schedule Page: 332.4 Line No.: 9 Column: b

Settlement Adjustment.

Schedule Page: 332.4 Line No.: 9 Column: g

Ancillary Services.

Schedule Page: 332.4 Line No.: 11 Column: b

Western Area Power Administration - Contract Termination Date: May 31, 2022.

Schedule Page: 332.4 Line No.: 13 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.4 Line No.: 15 Column: g

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to account 565 during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,028,546
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6		
7	Community and Economic Development and	
8	Corporate Memberships and Subscriptions:	
9	Clatsop Economic Development	12,500
10	Cottage Grove Area Chamber of Commerce	10,000
11	Economic Development Corp of Utah	102,000
12	Hood River County Chamber of Commerce	5,000
13	Idaho Economic Development	5,000
14	Klamath County Economic Development	10,000
15	Linn-Benton Community College	10,000
16	Newspaper Agency LLC	10,000
17	North-Northeast Business Assoc	5,000
18	Northwest Energy Efficiency	8,500
19	NW Grassroots and Communication	5,000
20	Oregon Economic Development Assoc	10,000
21	Oregon Entrepreneurs Network	5,000
22	Oregon Manufacturing Extension Part	6,500
23	Port of Columbia	14,000
24	Portland State University	5,000
25	Rural Development Initiatives Inc	5,000
26	Salem Economic Development	5,000
27	South Coast Development Council	7,500
28	Southern Oregon Regional Economic	6,000
29	Utah Center for Rural Life	5,000
30	Utah Sports Commission	79,572
31	Wyoming Business Council	5,000
32	Yakima County Development	5,000
33	Assoc of Regional Economic Development	5,500
34	Associated Oregon Industries	28,000
35	California Climate Action Registry	10,000
36	Economic Development for Central Oregon	15,000
37	Four County Eco Development Corp	25,000
38	Greater Yakima Chamber of Commerce	7,556
39	Idaho Mining Association	6,000
40	Intermountain Electrical Assoc	9,000
41	Laramie Economic Development Corp	5,000
42	Northern Tier Transmission Group	353,726
43	Northwest Power and Conservation	15,000
44	Oregon Business Association	11,000
45	Oregon Business Council	21,975
46	TOTAL	19,659,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Oregon Economic Development Assoc	5,000
7	Oregon Solar Energy Indstrs Assoc	5,000
8	Oregon Sports Authority Foundation	5,000
9	Pacific Northwest Utilities Conference Committee	69,069
10	Portland Business Alliance	39,250
11	Redmond Economic Development	5,000
12	Rocky Mountain Electrical League	18,000
13	Salt Lake Area Chamber of Commerce	30,555
14	UCA Usersgroup	5,000
15	Upstate California Economic	6,000
16	Utah Foundation	15,000
17	Utah Hispanic Chamber of Commerce	5,000
18	Utah Manufacturers Association	6,000
19	West Assoc	28,511
20	Western Electricity Coordinating Council	3,910,285
21	Western Energy Institute	41,003
22	Wyoming Business Alliance	7,600
23	Wyoming Taxpayers Association	7,128
24	Yakima County Development	7,500
25	Other	159,339
26		
27	Directors Fees - Regional Advisory Boards	113,982
28		
29	General:	
30	MidAmerican Mgmt Fee	8,353,029
31	PricewaterhouseCoopers LLP	7,600
32	Other	2,116
33		
34	Regulatory Asset Amortization:	
35	Glenrock Mine UT 1998 Case (Excluding Reclamation)	864,581
36	Glenrock Mine UT Stipulat. (Excluding Reclamation)	149,625
37	Transition Plan	3,892,299
38	WY Lakeside Liquidated Damages	18,278
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	19,659,625

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			29,820,783		29,820,783
2	Steam Production Plant	118,906,009				118,906,009
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,450,360		46,981		15,497,341
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	97,173,546				97,173,546
7	Transmission Plant	62,893,206				62,893,206
8	Distribution Plant	143,343,279				143,343,279
9	Regional Transmission and Market Operation					
10	General Plant	35,397,061		2,524,008		37,921,069
11	Common Plant-Electric					
12	TOTAL	473,163,461		32,391,772		505,555,233

B. Basis for Amortization Charges

The amortization of Limited-Term Electric Plant is based on straight-line amortization over the life of the asset.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	OTHER PRODUCTION						
13	Westside Mobile						
14	Generator						
15	344.00 OR	866	20.00		5.00		
16							
17	WIND GENERATION						
18	High Plains /						
19	McFadden Ridge I						
20	341.00 WY	7,785	24.87	-1.00	4.06		
21	343.00 WY	245,562	24.87	-1.00	4.06		
22	344.00 WY	6,947	24.87	-1.00	4.06		
23	345.00 WY	14,564	24.87	-1.00	4.06		
24	346.00 WY	114	24.87	-1.00	4.06		
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
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43							
44							
45							
46							
47							
48							
49							
50							

FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: b

Vehicle depreciation is charged to functional accounts. During the year ended December 31, 2009, vehicle depreciation expense of $13,886,246 was charged to functional accounts.

Schedule Page: 336 Line No.: 12 Column: e

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Public Service Commission of Utah:				
2	Annual Fee	3,943,569		3,943,569	
3	Rate Case		963,263	963,263	
4					
5	Public Utility Commission of Oregon:				
6	Annual Fee	3,157,187		3,157,187	
7	Rate Case		337,159	337,159	
8	Other State Regulatory Expenses		317,489	317,489	
9					
10	Public Service Commission of Wyoming:				
11	Annual Fee	1,291,764		1,291,764	
12	Rate Case		315,837	315,837	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	514,244		514,244	
17	Rate Case		109,993	109,993	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	394,653		394,653	
21	Rate Case		17,944	17,944	
22	Other State Regulatory Expenses		13,185	13,185	
23					
24	Public Utilities Commission of California:				
25	Annual Fee	861		861	
26	Rate Case		199,207	199,207	
27	Other State Regulatory Expenses		180,429	180,429	
28					
29	Rate Cases - All States		15,763	15,763	
30					
31	Federal Energy Regulatory Commission:				
32	Annual Fee	1,831,753		1,831,753	
33	Annual Land Use Fee	491,725		491,725	
34	Transmission Rate Case		2,368,722	2,368,722	
35					
36	Deferred Regulatory Commission Expense				-51,307
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	11,625,756	4,838,991	16,464,747	-51,307

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	3,943,569					2
Electric	928	963,263					3
							4
							5
Electric	928	3,157,187					6
Electric	928	337,159					7
Electric	928	317,489					8
							9
							10
Electric	928	1,291,764					11
Electric	928	315,837					12
							13
							14
							15
Electric	928	514,244					16
Electric	928	109,993					17
							18
							19
Electric	928	394,653					20
Electric	928	17,944					21
Electric	928	13,185					22
							23
							24
Electric	928	861					25
Electric	928	199,207					26
Electric	928	180,429					27
							28
Electric	928	15,763					29
							30
							31
Electric	928	1,831,753					32
Electric	928	491,725					33
Electric	928	2,368,722					34
							35
			448,756	928/254	336,071	61,378	36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		16,464,747	448,756		336,071	61,378	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	04/14/2010	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	108,675,266		
4	Transmission	11,574,674		
5	Regional Market			
6	Distribution	45,757,273		
7	Customer Accounts	46,069,991		
8	Customer Service and Informational	6,020,279		
9	Sales			
10	Administrative and General	3,903,169		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	222,000,652		
12	Maintenance			
13	Production	43,760,256		
14	Transmission	10,127,009		
15	Regional Market			
16	Distribution	83,245,095		
17	Administrative and General	2,291,743		
18	TOTAL Maintenance (Total of lines 13 thru 17)	139,424,103		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	152,435,522		
21	Transmission (Enter Total of lines 4 and 14)	21,701,683		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	129,002,368		
24	Customer Accounts (Transcribe from line 7)	46,069,991		
25	Customer Service and Informational (Transcribe from line 8)	6,020,279		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	6,194,912		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	361,424,755		361,424,755
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	361,424,755		361,424,755
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	146,881,411		146,881,411
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	146,881,411		146,881,411
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,162,675		9,162,675
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,162,675		9,162,675
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	24,418,419		24,418,419
79	Miscellaneous Other Income Deductions	352,592		352,592
80	Miscellaneous Nonoperating/Nonutility	797,544		797,544
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	25,568,555		25,568,555
96	TOTAL SALARIES AND WAGES	543,037,396		543,037,396

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						144,444
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	57,151,357	MWh	9,144,217	57,944,882	MWh	9,772,080
4	Energy Imbalance				-119,906	MWh	-3,571,023
5	Operating Reserve - Spinning	63,685,481	MWh	23,182,297	66,509,841	MWh	24,280,656
6	Operating Reserve - Supplement	63,685,481	MWh	23,182,297	65,590,206	MWh	23,937,632
7	Other						
8	Total (Lines 1 thru 7)	184,522,319		55,508,811	189,925,023		54,563,789

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month	Monthly Peak MW - Total	Day of Monthly Peak	Hour of Monthly Peak	Firm Network Service for Self	Firm Network Service for Others	Long-Term Firm Point-to-point Reservations	Other Long-Term Firm Service	Short-Term Firm Point-to-point Reservation	Other Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	January	21,509	27	800	8,524	136	5,057		6,384	1,408
2	February	18,981	10	1900	8,187	120	5,057		4,264	1,353
3	March	19,673	11	800	7,828	129	5,057		5,360	1,299
4	Total for Quarter 1	60,163			24,539	385	15,171		16,008	4,060
5	April	20,472	1	900	7,213	115	5,072		6,794	1,278
6	May	21,512	29	1600	7,912	99	4,991		7,111	1,399
7	June	22,124	29	1700	8,340	106	5,813		6,354	1,511
8	Total for Quarter 2	64,108			23,465	320	15,876		20,259	4,188
9	July	22,923	27	1700	9,420	106	5,813		5,948	1,636
10	August	21,918	20	1700	9,030	102	6,063		5,077	1,646
11	September	21,853	2	1700	8,470	110	6,106		5,608	1,559
12	Total for Quarter 3	66,694			26,920	318	17,982		16,633	4,841
13	October	16,160	28	800	7,412	109	6,148		1,271	1,220
14	November	15,666	30	1800	8,015	109	5,393		792	1,357
15	December	17,076	8	1900	9,332	126	5,393		660	1,565
16	Total for Quarter 4	48,902			24,759	344	16,934		2,723	4,142
17	Total Year to Date/Year	239,867			99,683	1,367	65,963		55,623	17,231

FOOTNOTE DATA

Schedule Page: 400 Line No.: 4 Column: e

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: f

Reflects actual demands of control area load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: g

Reflects reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: i

Reflects reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: e

Refer to footnote for line 4 column (e).

Schedule Page: 400 Line No.: 8 Column: f

Refer to footnote for line 4 column (f).

Schedule Page: 400 Line No.: 8 Column: g

Refer to footnote for line 4 column (g).

Schedule Page: 400 Line No.: 8 Column: i

Refer to footnote for line 4 column (i).

Schedule Page: 400 Line No.: 12 Column: e

Refer to footnote for line 4 column (e).

Schedule Page: 400 Line No.: 12 Column: f

Refer to footnote for line 4 column (f).

Schedule Page: 400 Line No.: 12 Column: g

Refer to footnote for line 4 column (g).

Schedule Page: 400 Line No.: 12 Column: i

Refer to footnote for line 4 column (i).

Schedule Page: 400 Line No.: 16 Column: e

Refer to footnote for line 4 column (e).

Schedule Page: 400 Line No.: 16 Column: f

Refer to footnote for line 4 column (f).

Schedule Page: 400 Line No.: 16 Column: g

Refer to footnote for line 4 column (g).

Schedule Page: 400 Line No.: 16 Column: i

Refer to footnote for line 4 column (i).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	52,709,525
3	Steam	46,087,590	23	Requirements Sales for Resale (See instruction 4, page 311.)	205,608
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	12,143,453
5	Hydro-Conventional	3,545,718	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	-1,300	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	131,439
7	Other	8,772,955	27	Total Energy Losses	4,196,858
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	69,386,883
9	Net Generation (Enter Total of lines 3 through 8)	58,404,963			
10	Purchases	11,462,391			
11	Power Exchanges:				
12	Received	14,027,658			
13	Delivered	14,213,609			
14	Net Exchanges (Line 12 minus line 13)	-185,951			
15	Transmission For Other (Wheeling)				
16	Received	14,464,153			
17	Delivered	14,464,153			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses	-294,520			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	69,386,883			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,408,275	1,152,395	8,524	27	0800 PST
30	February	5,613,917	1,034,060	8,187	10	1900 PST
31	March	5,974,490	1,267,096	7,828	11	0800 PST
32	April	5,151,385	894,687	7,213	1	0900 PDT
33	May	5,300,712	878,138	7,912	29	1600 PDT
34	June	5,138,144	785,696	8,340	29	1700 PDT
35	July	6,213,028	901,436	9,420	27	1700 PDT
36	August	6,129,956	1,109,686	9,042	3	1700 PDT
37	September	5,575,955	972,815	8,499	2	1600 PDT
38	October	5,543,767	1,034,091	7,414	28	0900 PDT
39	November	5,832,041	1,076,664	8,015	30	1800 PST
40	December	6,505,213	1,036,689	9,336	9	0800 PST
41	TOTAL	69,386,883	12,143,453			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Carbon* (b)			Plant Name: *Cholla* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Full Outdoor		
3	Year Originally Constructed	1954			1981		
4	Year Last Unit was Installed	1957			1981		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	188.60			414.00		
6	Net Peak Demand on Plant - MW (60 minutes)	176			385		
7	Plant Hours Connected to Load	8717			8462		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	172			395		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	70			0		
12	Net Generation, Exclusive of Plant Use - KWh	1211875000			2877189000		
13	Cost of Plant: Land and Land Rights	956546			2448255		
14	Structures and Improvements	14711825			57386063		
15	Equipment Costs	103555029			459550611		
16	Asset Retirement Costs	6527359			39000		
17	Total Cost	125750759			519423929		
18	Cost per KW of Installed Capacity (line 17/5) Including	666.7591			1254.6472		
19	Production Expenses: Oper, Supv, & Engr	61684			1216352		
20	Fuel	19612994			56204755		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1396202			5101692		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1810205			1150021		
26	Misc Steam (or Nuclear) Power Expenses	4934749			1502518		
27	Rents	170			1762		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			1912378		
30	Maintenance of Structures	336038			938302		
31	Maintenance of Boiler (or reactor) Plant	2988372			3403827		
32	Maintenance of Electric Plant	1556410			410626		
33	Maintenance of Misc Steam (or Nuclear) Plant	294454			3020817		
34	Total Production Expenses	32991278			74863050		
35	Expenses per Net KWh	0.0272			0.0260		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	561433	3456	0	1553172	1530	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12079	140000	0	9529	130042	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	34.043	86.065	0.000	33.796	97.687	0.000
41	Average Cost of Fuel per Unit Burned	34.404	86.065	0.000	36.091	97.687	0.000
42	Average Cost of Fuel Burned per Million BTU	1.424	14.637	1.444	1.894	17.887	1.898
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.016	0.019	0.000	0.019
44	Average BTU per KWh Net Generation	11191.461	16.771	11208.232	10287.940	2.904	10290.844

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

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

Plant Name: Colstrip (d)	Plant Name: Craig (e)	Plant Name: Dave Johnston (f)	Line No.
Steam	Steam	Steam	1
Conventional	Outdoor Boiler	Semi-Outdoor	2
1984	1979	1959	3
1986	1980	1972	4
155.60	172.10	816.80	5
151	165	766	6
8531	8760	8760	7
0	0	0	8
148	165	762	9
0	0	0	10
0	0	189	11
873534000	1349226000	5015234000	12
1355853	137086	10451083	13
58203289	36283734	57419130	14
158047854	129835925	478527178	15
39236	35149	11441950	16
217646232	166291894	557839341	17
1398.7547	966.2516	682.9571	18
17204	346038	709742	19
10373467	19362415	45387118	20
0	0	0	21
788274	1434977	-40618	22
0	0	0	23
0	0	0	24
20783	632520	0	25
1457012	1073216	17159533	26
21677	0	148543	27
0	0	0	28
261059	620263	0	29
341245	398230	2442564	30
2577695	2775904	12629287	31
304935	584242	8595794	32
395840	804594	1702185	33
16559191	28032399	88734148	34
0.0190	0.0208	0.0177	35

Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
547384	1035	0	667587	48	0	3561945	18425	0	38
8504	140000	0	10023	133693	0	7986	140000	0	39
17.956	92.173	0.000	27.575	121.943	0.000	12.288	85.805	0.000	40
18.777	92.173	0.000	28.938	121.943	0.000	12.298	85.805	0.000	41
1.104	15.675	1.114	1.444	21.721	1.447	0.770	14.593	0.796	42
0.012	0.000	0.012	0.014	0.000	0.014	0.009	0.000	0.009	43
10657.757	6.965	10664.722	9918.615	0.199	9918.813	11343.627	21.602	11365.228	44

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

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Line No.	Item (a)	Plant Name: Hayden (b)			Plant Name: Hunter Unit No. 1 (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Outdoor Boiler		
3	Year Originally Constructed	1965			1978		
4	Year Last Unit was Installed	1976			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	81.30			457.70		
6	Net Peak Demand on Plant - MW (60 minutes)	79			406		
7	Plant Hours Connected to Load	8741			8165		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	78			403		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	572069000			2988412000		
13	Cost of Plant: Land and Land Rights	379735			9688975		
14	Structures and Improvements	5973764			63023096		
15	Equipment Costs	62511609			232879738		
16	Asset Retirement Costs	20877			953193		
17	Total Cost	68885985			306545002		
18	Cost per KW of Installed Capacity (line 17/5) Including	847.3061			669.7509		
19	Production Expenses: Oper, Supv, & Engr	274635			9		
20	Fuel	10812381			39453933		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	936512			2885015		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	275031			0		
26	Misc Steam (or Nuclear) Power Expenses	658249			1866496		
27	Rents	0			36		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	231859			0		
30	Maintenance of Structures	144681			2020238		
31	Maintenance of Boiler (or reactor) Plant	1097242			5066533		
32	Maintenance of Electric Plant	950135			1066457		
33	Maintenance of Misc Steam (or Nuclear) Plant	371286			92204		
34	Total Production Expenses	15752011			52450921		
35	Expenses per Net KWh	0.0275			0.0176		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	274462	388	0	1429788	3447	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11451	133333	0	11494	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	36.836	124.046	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	39.091	124.046	0.000	27.370	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.707	22.150	1.720	1.191	15.797	1.200
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.019	0.013	0.000	0.013
44	Average BTU per KWh Net Generation	10987.432	3.798	10991.230	10998.930	6.783	11005.713

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

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Plant Name: Hunter Unit No. 2 (d)	Plant Name: Hunter Unit No. 3 (e)	Plant Name: Hunter - Total Plant (f)	Line No.
Steam	Steam	Steam	1
Outdoor Boiler	Outdoor Boiler	Outdoor Boiler	2
1980	1983	1978	3
1980	1983	1983	4
294.50	495.60	1247.80	5
260	465	1118	6
7977	8076	8760	7
0	0	0	8
259	460	1122	9
0	0	0	10
0	0	223	11
1919186000	3163584000	8071182000	12
9688975	10275401	29653351	13
51902741	91048170	205974007	14
155835995	409607088	798322821	15
953193	953193	2859579	16
218380904	511883852	1036809758	17
741.5311	1032.8568	830.9102	18
0	0	9	19
25483250	39919514	104856697	20
0	0	0	21
2879751	2895780	8660546	22
0	0	0	23
0	0	0	24
0	0	0	25
-3012030	2495825	1350291	26
36	36	108	27
0	0	0	28
0	0	0	29
1949545	1841148	5810931	30
5095985	8726696	18889214	31
1170308	1187195	3423960	32
115600	211740	419544	33
33682445	57277934	143411300	34
0.0176	0.0181	0.0178	35

Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
916714	3490	0	1429028	10817	0	3775530	17754	0	38
11613	140000	0	11414	140000	0	11508	140000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	27.494	90.181	0.000	40
27.449	0.000	0.000	27.262	0.000	0.000	27.349	90.181	0.000	41
1.182	15.598	1.196	1.194	15.106	1.221	1.188	15.337	1.205	42
0.013	0.000	0.013	0.012	0.000	0.012	0.013	0.000	0.013	43
11093.719	10.694	11104.413	10311.604	20.105	10331.709	10766.182	12.935	10779.117	44

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

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Line No.	Item (a)	Plant Name: *Huntington* (b)			Plant Name: *Jim Bridger* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Semi-Outdoor		
3	Year Originally Constructed	1974			1974		
4	Year Last Unit was Installed	1977			1979		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	996.00			1545.10		
6	Net Peak Demand on Plant - MW (60 minutes)	893			1427		
7	Plant Hours Connected to Load	8716			8760		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	895			1411		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	166			346		
12	Net Generation, Exclusive of Plant Use - KWh	6753764000			10205788000		
13	Cost of Plant: Land and Land Rights	2386782			1161925		
14	Structures and Improvements	114795130			139315508		
15	Equipment Costs	519092603			842656040		
16	Asset Retirement Costs	2528174			4672990		
17	Total Cost	638802689			987806463		
18	Cost per KW of Installed Capacity (line 17/5) Including	641.3682			639.3156		
19	Production Expenses: Oper, Supv, & Engr	27278			18005919		
20	Fuel	72225359			153880101		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	7937097			3955919		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			6741		
26	Misc Steam (or Nuclear) Power Expenses	10861739			-14874547		
27	Rents	99829			162397		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1148565			565038		
30	Maintenance of Structures	2102720			8014043		
31	Maintenance of Boiler (or reactor) Plant	8062385			24007785		
32	Maintenance of Electric Plant	2080488			8326771		
33	Maintenance of Misc Steam (or Nuclear) Plant	1211100			2904601		
34	Total Production Expenses	105756560			204954768		
35	Expenses per Net KWh	0.0157			0.0201		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite	Coal	Oil	Composite
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2742685	10980	0	5605754	17615	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12329	140000	0	9219	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	25.969	93.715	0.000	27.430	94.516	0.000
41	Average Cost of Fuel per Unit Burned	25.959	93.715	0.000	27.153	94.516	0.000
42	Average Cost of Fuel Burned per Million BTU	1.053	15.938	1.067	1.473	16.074	1.487
43	Average Cost of Fuel Burned per KWh Net Gen	0.011	0.000	0.011	0.015	0.000	0.015
44	Average BTU per KWh Net Generation	10013.541	9.560	10023.101	10126.934	10.149	10137.083

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

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Plant Name: *Naughton* (d)	Plant Name: *Wyodak* (e)	Plant Name: *Gadsby Steam Plant* (f)	Line No.
Steam	Steam	Steam	1
Outdoor Boiler	Conventional	Outdoor	2
1963	1978	1951	3
1971	1978	1955	4
707.20	289.70	251.60	5
710	280	200	6
8760	8315	3753	7
0	0	0	8
700	268	231	9
0	0	0	10
144	67	38	11
4752632000	2173325000	256104000	12
4290826	210526	1252090	13
68909211	50622953	15072596	14
366019199	278115837	58376560	15
6618388	613826	587008	16
445837624	329563142	75288254	17
630.4265	1137.6015	299.2379	18
324827	230568	112089	19
74045306	19381981	34139992	20
0	0	0	21
5333061	0	0	22
0	0	0	23
0	0	0	24
9228	0	0	25
9224358	4272348	4077590	26
0	6288	0	27
0	0	0	28
1225396	5556	0	29
1439317	474208	220739	30
10677987	5398045	1772321	31
4789264	1451664	850210	32
1024574	288544	188443	33
108093318	31509202	41361384	34
0.0227	0.0145	0.1615	35

Coal	Gas	Composite	Coal	Oil	Composite	Gas			
Tons	MCF		Tons	Barrels		MCF			37
2494866	409757	0	1608054	6243	0	3628836	0	0	38
9907	1033	0	7968	140000	0	1043	0	0	39
28.529	6.654	0.000	11.782	98.704	0.000	9.408	0.000	0.000	40
28.586	6.654	0.000	11.670	98.704	0.000	9.408	0.000	0.000	41
1.443	6.440	1.485	0.732	16.787	0.755	9.024	0.000	0.000	42
0.015	0.001	0.016	0.009	0.000	0.009	0.133	0.000	0.000	43
10400.984	89.078	10490.062	11790.384	16.892	11807.276	14772.370	0.000	0.000	44

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Item (a)	Plant Name: *Little Mountain* (b)			Plant Name: *Hermiston* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor Boiler			Outdoor		
3	Year Originally Constructed	1972			1996		
4	Year Last Unit was Installed	1972			1996		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	16.00			279.60		
6	Net Peak Demand on Plant - MW (60 minutes)	17			245		
7	Plant Hours Connected to Load	7976			7899		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	14			237		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	6			0		
12	Net Generation, Exclusive of Plant Use - KWh	109399000			1550620000		
13	Cost of Plant: Land and Land Rights	635			842245		
14	Structures and Improvements	337028			12844996		
15	Equipment Costs	5211774			156147473		
16	Asset Retirement Costs	0			214373		
17	Total Cost	5549437			170049087		
18	Cost per KW of Installed Capacity (line 17/5) Including	346.8398			608.1870		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	17244593			52931527		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	906225			7483824		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	712185			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	18863003			60415351		
35	Expenses per Net KWh	0.1724			0.0390		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	1977227	0	0	11250180	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1046	0	0	1019	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.722	0.000	0.000	4.705	0.000	0.000
41	Average Cost of Fuel per Unit Burned	8.722	0.000	0.000	4.705	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	8.339	0.000	0.000	4.615	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.158	0.000	0.000	0.034	0.000	0.000
44	Average BTU per KWh Net Generation	18902.440	0.000	0.000	7397.100	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Plant Name: Blundell (d)	Plant Name: Camas Co-Gen (e)	Plant Name: Chehalis (f)	Line No.
Steam - Geothermal	Steam	Combined Cycle	1
Indoor	Outdoor Boiler	Outdoor	2
1984	1996	2003	3
2007	1996	2003	4
38.10	61.50	593.30	5
36	46	519	6
8594	6764	4652	7
0	0	0	8
34	22	520	9
0	0	0	10
22	0	18	11
279121000	86384000	1747252000	12
41195596	0	1973791	13
7900332	5733734	23230141	14
68774244	28716806	313849140	15
1336278	0	689117	16
119206450	34450540	339742189	17
3128.7782	560.1714	572.6314	18
50045	0	83486	19
0	0	89420353	20
0	0	0	21
5426	0	0	22
3597576	0	0	23
0	0	0	24
0	0	2661898	25
1806790	0	0	26
9640	0	15909	27
0	0	0	28
0	0	0	29
162048	0	10917	30
153519	0	0	31
403022	0	2875548	32
55291	0	0	33
6243357	0	95068111	34
0.0224	0.0000	0.0544	35
		Gas	36
		MCF	37
0 0 0	0 0 0	12530185 0 0	38
0 0 0	0 0 0	1032 0 0	39
0.000 0.000 0.000	0.000 0.000 0.000	7.136 0.000 0.000	40
0.000 0.000 0.000	0.000 0.000 0.000	7.136 0.000 0.000	41
0.000 0.000 0.000	0.000 0.000 0.000	6.918 0.000 0.000	42
0.000 0.000 0.000	0.000 0.000 0.000	0.051 0.000 0.000	43
0.000 0.000 0.000	0.000 0.000 0.000	7397.744 0.000 0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

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

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

Line No.	Item (a)	Plant Name: *Gadsby Gas Peakers* (b)			Plant Name: *Currant Creek* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2002			2005		
4	Year Last Unit was Installed	2002			2006		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	181.10			566.90		
6	Net Peak Demand on Plant - MW (60 minutes)	121			568		
7	Plant Hours Connected to Load	5982			7654		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	122			550		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			19		
12	Net Generation, Exclusive of Plant Use - KWh	349713000			2464463000		
13	Cost of Plant: Land and Land Rights	0			3403277		
14	Structures and Improvements	4241952			43802097		
15	Equipment Costs	72822026			305516243		
16	Asset Retirement Costs	0			134848		
17	Total Cost	77063978			352856465		
18	Cost per KW of Installed Capacity (line 17/5) Including	425.5327			622.4316		
19	Production Expenses: Oper, Supv, & Engr	0			99940		
20	Fuel	35489120			147818357		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1641160			2351396		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			6149		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	193326			250824		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	2966597			6436998		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	40290203			156963664		
35	Expenses per Net KWh	0.1152			0.0637		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	4019844	0	0	17314372	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1046	0	0	1052	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.828	0.000	0.000	8.537	0.000	0.000
41	Average Cost of Fuel per Unit Burned	8.828	0.000	0.000	8.537	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	8.442	0.000	0.000	8.118	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.101	0.000	0.000	0.060	0.000	0.000
44	Average BTU per KWh Net Generation	12020.788	0.000	0.000	7388.233	0.000	0.000

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

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

Plant Name: *Lake Side* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combined Cycle			1
Outdoor			2
2007			3
2007			4
591.30	0.00	0.00	5
597	0	0	6
5912	0	0	7
0	0	0	8
558	0	0	9
0	0	0	10
22	0	0	11
2099013000	0	0	12
17296760	0	0	13
27700094	0	0	14
306701044	0	0	15
0	0	0	16
351697898	0	0	17
594.7876	0.0000	0.0000	18
133539	0	0	19
118839066	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
2606241	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
1088964	0	0	30
0	0	0	31
1885555	0	0	32
0	0	0	33
124553365	0	0	34
0.0593	0.0000	0.0000	35
Gas			36
MCF			37
14857205	0	0	38
1032	0	0	39
7.999	0.000	0.000	40
7.999	0.000	0.000	41
7.754	0.000	0.000	42
0.057	0.000	0.000	43
7301.651	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: c

Cholla

The Cholla Plant is operated by Arizona Public Service Company. PacifiCorp owns Unit No. 4 plus 36.85% of related common facilities. Data reported represents PacifiCorp's share. PacifiCorp does not have employees at the Cholla Plant.

Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: -1 Column: d

Colstrip

The Colstrip Plant is operated by PPL Montana, LLC and is jointly owned. Data reported represents PacifiCorp's 10% share of Colstrip Plant Units No. 3 and No. 4. PacifiCorp does not have employees at the Colstrip Plant.

Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: -1 Column: e

Craig

The Craig Plant is operated by Tri-State Generation and Transmission Association and is jointly owned. Data reported represents PacifiCorp's 19.28% share of Craig Plant Units No. 1 and No. 2 and 12.86% of common facilities. PacifiCorp does not have employees at the Craig Plant.

Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: -1 Column: b

Hayden

The Hayden Plant is operated by Public Service Company of Colorado and is jointly owned. Data reported represents PacifiCorp's 24.5% (45 MW) share of Hayden Unit No. 1, 12.6% (33 MW) share of Hayden Unit No. 2 and 17.5% of common facilities. PacifiCorp does not have employees at the Hayden Plant.

Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: -1 Column: c

Hunter Plant Unit No. 1

Hunter Plant Unit No. 1 is owned by PacifiCorp and Utah Municipal Power Agency with an undivided interest of 93.75% and 6.25%, respectively. Data reported in column (c) represents PacifiCorp's share. Costs to operate and maintain this unit are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2009 were $1.1 million and were primarily charged to account 506.

Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: -1 Column: d

Hunter Plant Unit No. 2

Hunter Plant Unit No. 2 is owned by PacifiCorp, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems, each with an undivided interest of 60.31%, 25.108% and 14.582% respectively. Data reported in column (d) represents PacifiCorp's share. Costs to operate and maintain this unit are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2009 were $6.2 million and were primarily charged to account 506.

Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: -1 Column: f

Hunter

Hunter Unit No. 1 is owned by PacifiCorp and Utah Municipal Power Agency with an undivided interest of 93.75% and 6.25% respectively. Hunter Unit No. 2 is owned by PacifiCorp, Deseret Power Electric Cooperative and Utah Associated Municipal Power Systems, each with an undivided interest of 60.31%, 25.108% and 14.582% respectively. Data in column (f) represents PacifiCorp's share. Costs to operate and maintain this plant are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2009 were $7.3 million and were primarily charged to account 506.

Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: -1 Column: c

Jim Bridger

Jim Bridger Plant is operated by PacifiCorp and column (c) represents PacifiCorp's share. Ownership of the plant is as follows: PacifiCorp 66 2/3%, Idaho Power Company 33 1/3%. Costs to operate and maintain this plant are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2009 were $25.2 million and were primarily charged to account 506.

Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: -1 Column: e

Wyodak

Wyodak Plant is operated by PacifiCorp and column (e) represents PacifiCorp's share. Ownership of the plant is as follows: PacifiCorp 80%, Black Hills Corporation 20%. Costs to operate and maintain this plant are charged to appropriate FERC accounts. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2009 were $3.4 million and were primarily charged to account 506.

Fuel oil is used for start-up purposes.

Schedule Page: 402.3 Line No.: -1 Column: c

Hermiston

The Hermiston Plant is operated by Hermiston Generating Company, L.P. and is jointly owned. Data reported represents PacifiCorp's 50.0% share of the Hermiston Plant. See Page 326- Purchased Power of this Form No. 1 for further information on Hermiston Generating Company, L.P. PacifiCorp does not have any employees at the Hermiston Plant.

Schedule Page: 402.3 Line No.: -1 Column: d

Blundell

All or some of the renewable energy attributes associated with this generation may be: (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 402.3 Line No.: -1 Column: e

Camas Co-Gen

PacifiCorp owns the steam turbine generator and associated systems directly related to the operation of this unit at Georgia-Pacific Corporation's Camas, Washington paper mill. Modifications and upgrades to the existing Camas paper mill were necessary to supply steam to the turbine and to ensure continued operation of the unit in the event of mill closure. Georgia-Pacific retained ownership of these modifications. Georgia-Pacific supplies the fuel and delivers the steam to PacifiCorp's turbine. PacifiCorp is responsible for major maintenance costs only on the repair of the turbine generator and auxiliary equipment. None of the facilities are jointly owned. Each asset is wholly owned, either by PacifiCorp or Georgia-Pacific Corporation. PacifiCorp does not have employees at the Camas Paper Mill.

Schedule Page: 402.3 Line No.: -1 Column: f

Chehalis

On September 15, 2008, after having received the requisite regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC ("Chehalis"), an entity owning a 520-megawatt ("MW") natural gas-fired generating facility located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the facility, which was included in account 102, Electric plant purchased or sold. Chehalis was merged into PacifiCorp immediately following the acquisition. The results of the facility's operations have been included in PacifiCorp's financial statements since the acquisition date. In May 2009, the Federal Energy Regulatory Commission approved the journal entries called for by the Uniform System of Accounts, with modifications to the purchase accounting adjustments for asset retirement obligations. Accordingly, PacifiCorp cleared account 102 and recorded the purchase to the appropriate plant accounts.

Schedule Page: 402 Line No.: 36 Column: b2

Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: f2

Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: e2

FOOTNOTE DATA

Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: b2

Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2

Natural gas is used for start-up purposes.

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 2082 Plant Name: Copco No. 1 (b)	FERC Licensed Project No. 2082 Plant Name: Copco No. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1918	1925
4	Year Last Unit was Installed	1922	1925
5	Total installed cap (Gen name plate Rating in MW)	20.00	27.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	24	29
7	Plant Hours Connect to Load	5,831	5,555
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	28	34
10	(b) Under the Most Adverse Oper Conditions	28	34
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	79,739,000	97,920,000
13	Cost of Plant		
14	Land and Land Rights	180,375	20,914
15	Structures and Improvements	1,600,534	2,191,526
16	Reservoirs, Dams, and Waterways	2,644,597	2,954,724
17	Equipment Costs	5,151,002	10,337,560
18	Roads, Railroads, and Bridges	105,442	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	9,681,950	15,984,312
21	Cost per KW of Installed Capacity (line 20 / 5)	484.0975	592.0116
22	Production Expenses		
23	Operation Supervision and Engineering	153,358	218,208
24	Water for Power	620	837
25	Hydraulic Expenses	1,116	1,507
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	437,081	451,712
28	Rents	3,338	4,579
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	6,840	16,169
31	Maintenance of Reservoirs, Dams, and Waterways	73,118	149,902
32	Maintenance of Electric Plant	35,154	94,747
33	Maintenance of Misc Hydraulic Plant	32,337	34,939
34	Total Production Expenses (total 23 thru 33)	742,962	972,600
35	Expenses per net KWh	0.0093	0.0099

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1927 Plant Name: Clearwater No. 1 (d)	FERC Licensed Project No. 1927 Plant Name: Clearwater No. 2 (e)	FERC Licensed Project No. 2420 Plant Name: Cutler (f)	Line No.
Run-of-River	Run-of-River	Storage	1
Outdoor	Outdoor	Conventional	2
1953	1953	1927	3
1953	1953	1927	4
15.00	26.00	30.00	5
13	17	29	6
7,978	8,294	5,401	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
35,759,000	41,993,000	88,528,000	12
			13
0	0	3,505,129	14
1,191,014	1,625,933	3,891,430	15
4,428,345	14,775,194	6,645,544	16
1,189,202	1,518,619	14,548,820	17
39,142	250,151	572,059	18
0	0	0	19
6,847,703	18,169,897	29,162,982	20
456.5135	698.8422	972.0994	21
			22
91,907	153,750	246,334	23
12,270	21,268	930	24
63,963	110,870	70,134	25
0	0	0	26
226,354	448,115	602,597	27
6,084	10,546	271	28
145	251	0	29
26,586	39,112	1,657	30
53,258	46,591	26,712	31
45,771	10,370	8,623	32
46,370	80,374	174,227	33
572,708	921,247	1,131,485	34
0.0160	0.0219	0.0128	35

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Fish Creek (b)	FERC Licensed Project No. 20 Plant Name: Grace (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1952	1908
4	Year Last Unit was Installed	1952	1923
5	Total installed cap (Gen name plate Rating in MW)	11.00	33.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	31
7	Plant Hours Connect to Load	4,222	7,576
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	10	33
10	(b) Under the Most Adverse Oper Conditions	10	33
11	Average Number of Employees	1	3
12	Net Generation, Exclusive of Plant Use - Kwh	33,450,000	59,082,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	825,661	1,618,231
16	Reservoirs, Dams, and Waterways	12,685,388	9,208,496
17	Equipment Costs	1,336,038	4,231,900
18	Roads, Railroads, and Bridges	519,399	97,073
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,366,486	15,217,869
21	Cost per KW of Installed Capacity (line 20 / 5)	1,396.9533	461.1475
22	Production Expenses		
23	Operation Supervision and Engineering	83,758	260,547
24	Water for Power	8,998	1,023
25	Hydraulic Expenses	46,907	83,641
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	199,249	1,332,068
28	Rents	4,462	927
29	Maintenance Supervision and Engineering	106	0
30	Maintenance of Structures	16,725	14,694
31	Maintenance of Reservoirs, Dams, and Waterways	25,340	126,159
32	Maintenance of Electric Plant	11,557	41,959
33	Maintenance of Misc Hydraulic Plant	37,150	110,935
34	Total Production Expenses (total 23 thru 33)	434,252	1,971,953
35	Expenses per net KWh	0.0130	0.0334

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2082 Plant Name: Iron Gate (d)	FERC Licensed Project No. 2082 Plant Name: JC Boyle (e)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 1 (f)	Line No.
Storage	Storage	Storage	1
Outdoor	Outdoor	Outdoor	2
1962	1958	1955	3
1962	1958	1955	4
18.00	97.98	31.99	5
18	79	30	6
8,631	6,103	8,148	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
112,647,000	222,073,000	127,486,000	12
			13
341,706	26,277	0	14
4,610,225	2,439,780	1,792,374	15
12,930,242	14,564,782	9,130,690	16
2,248,775	15,041,090	6,083,729	17
1,076,116	886,710	475,419	18
0	0	0	19
21,207,064	32,958,639	17,482,212	20
1,178.1702	336.3813	546.4899	21
			22
147,737	440,944	226,707	23
558	3,038	26,167	24
1,004	5,467	136,413	25
0	0	0	26
326,255	601,583	507,872	27
3,004	1,044	12,976	28
0	0	309	29
556,758	40,519	52,907	30
55,282	107,365	96,662	31
64,257	24,874	24,844	32
23,292	62,966	98,891	33
1,178,147	1,287,800	1,183,748	34
0.0105	0.0058	0.0093	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Lemolo No. 2 (b)	FERC Licensed Project No. 935 Plant Name: Merwin (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of River	Storage (Re-Reg)
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1956	1931
4	Year Last Unit was Installed	1956	1958
5	Total installed cap (Gen name plate Rating in MW)	33.00	136.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	148
7	Plant Hours Connect to Load	4,468	8,670
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	34	151
10	(b) Under the Most Adverse Oper Conditions	34	151
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	89,595,000	452,443,000
13	Cost of Plant		
14	Land and Land Rights	0	1,086,417
15	Structures and Improvements	3,283,342	36,685,802
16	Reservoirs, Dams, and Waterways	23,240,294	10,004,954
17	Equipment Costs	11,398,052	15,980,829
18	Roads, Railroads, and Bridges	1,649,779	2,092,829
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	39,571,467	65,850,831
21	Cost per KW of Installed Capacity (line 20 / 5)	1,199.1354	484.1973
22	Production Expenses		
23	Operation Supervision and Engineering	189,650	1,257,788
24	Water for Power	26,994	24,183
25	Hydraulic Expenses	140,720	526,728
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	986,647	1,019,052
28	Rents	13,386	2,547
29	Maintenance Supervision and Engineering	319	0
30	Maintenance of Structures	57,576	40,600
31	Maintenance of Reservoirs, Dams, and Waterways	58,319	77,178
32	Maintenance of Electric Plant	10,923	74,003
33	Maintenance of Misc Hydraulic Plant	102,013	270,282
34	Total Production Expenses (total 23 thru 33)	1,586,547	3,292,361
35	Expenses per net KWh	0.0177	0.0073

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1927 Plant Name: Toketee (d)	FERC Licensed Project No. 20 Plant Name: Oneida (e)	FERC Licensed Project No. 2630 Plant Name: Prospect No. 2 (f)	Line No.
Storage	Storage	Run-of River	1
Conventional	Conventional	Conventional	2
1949	1915	1928	3
1950	1920	1928	4
42.50	30.00	32.00	5
44	19	36	6
6,103	8,744	8,609	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
213,049,000	33,079,000	226,390,000	12
			13
0	36,698	105,168	14
2,210,838	1,407,894	2,778,308	15
8,352,148	5,088,376	24,751,241	16
3,266,170	5,155,612	3,600,442	17
257,079	511,059	267,572	18
0	0	0	19
14,086,235	12,199,639	31,502,731	20
331.4408	406.6546	984.4603	21
			22
255,174	233,533	681,049	23
34,765	930	992	24
181,230	76,037	1,786	25
0	0	0	26
635,548	724,713	477,821	27
17,239	843	4,901	28
410	0	0	29
66,111	12,434	24,529	30
79,265	448	199,281	31
92,992	82,888	5,884	32
132,171	72,184	77,569	33
1,494,905	1,204,010	1,473,812	34
0.0070	0.0364	0.0065	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 1927 Plant Name: Slide Creek (b)	FERC Licensed Project No. 20 Plant Name: Soda (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1951	1924
4	Year Last Unit was Installed	1951	1924
5	Total installed cap (Gen name plate Rating in MW)	18.00	14.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	18	9
7	Plant Hours Connect to Load	7,892	6,319
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	18	14
10	(b) Under the Most Adverse Oper Conditions	18	14
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	80,364,000	11,824,000
13	Cost of Plant		
14	Land and Land Rights	0	511,675
15	Structures and Improvements	1,802,822	672,316
16	Reservoirs, Dams, and Waterways	5,640,915	5,763,324
17	Equipment Costs	1,365,431	2,203,022
18	Roads, Railroads, and Bridges	16,778	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	8,825,946	9,150,337
21	Cost per KW of Installed Capacity (line 20 / 5)	490.3303	653.5955
22	Production Expenses		
23	Operation Supervision and Engineering	103,850	120,563
24	Water for Power	14,724	434
25	Hydraulic Expenses	76,756	35,484
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	283,168	426,089
28	Rents	7,301	393
29	Maintenance Supervision and Engineering	174	0
30	Maintenance of Structures	29,830	12,656
31	Maintenance of Reservoirs, Dams, and Waterways	26,328	35,568
32	Maintenance of Electric Plant	45,354	22,829
33	Maintenance of Misc Hydraulic Plant	56,716	31,185
34	Total Production Expenses (total 23 thru 33)	644,201	685,201
35	Expenses per net KWh	0.0080	0.0580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1927 Plant Name: Soda Springs (d)	FERC Licensed Project No. 2111 Plant Name: Swift No. 1 (e)	FERC Licensed Project No. 2071 Plant Name: Yale (f)	Line No.
Storage (Re-Reg)	Storage	Storage	1
Outdoor	Conventional	Conventional	2
1952	1958	1953	3
1952	1958	1953	4
11.00	240.00	134.00	5
12	248	163	6
7,802	5,598	5,476	7
			8
12	264	164	9
12	263	164	10
1	2	2	11
51,112,000	591,615,000	540,238,000	12
			13
0	7,813,808	3,299,822	14
1,127,558	8,891,329	6,822,963	15
13,607,662	41,176,239	27,333,548	16
2,192,253	16,092,927	14,887,463	17
56,124	1,004,508	1,395,512	18
0	0	0	19
16,983,597	74,978,811	53,739,308	20
1,543.9634	312.4117	401.0396	21
			22
72,971	2,156,956	1,229,924	23
8,998	42,676	23,828	24
46,907	1,218,758	518,982	25
0	0	0	26
223,871	1,371,561	877,628	27
4,462	70,294	2,509	28
106	0	0	29
24,328	49,185	22,972	30
42,934	18,508	30,505	31
31,664	136,150	272,602	32
34,502	462,509	274,062	33
490,743	5,526,597	3,253,012	34
0.0096	0.0093	0.0060	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Olmsted (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1904	
4	Year Last Unit was Installed	1922	
5	Total installed cap (Gen name plate Rating in MW)	10.30	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	10	0
7	Plant Hours Connect to Load	7,162	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	10	0
10	(b) Under the Most Adverse Oper Conditions	10	0
11	Average Number of Employees	4	0
12	Net Generation, Exclusive of Plant Use - Kwh	25,606,000	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	369,124	0
16	Reservoirs, Dams, and Waterways	529,217	0
17	Equipment Costs	31,914	0
18	Roads, Railroads, and Bridges	12,641	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	942,896	0
21	Cost per KW of Installed Capacity (line 20 / 5)	91.5433	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	81,619	0
24	Water for Power	319	0
25	Hydraulic Expenses	24,079	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	262,859	0
28	Rents	93	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	56	0
31	Maintenance of Reservoirs, Dams, and Waterways	15,301	0
32	Maintenance of Electric Plant	14,177	0
33	Maintenance of Misc Hydraulic Plant	86,547	0
34	Total Production Expenses (total 23 thru 33)	485,050	0
35	Expenses per net KWh	0.0189	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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

Copco No. 1

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406 Line No.: -1 Column: c

Copco No. 2

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406 Line No.: -1 Column: d

Clearwater No. 1

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Clearwater No. 2

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Cutler

Costs reported for this plant do not include significant intangible costs due to relicensing, which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $1,036,287.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Copco No. 1

Pondage for peaking - storage, Upper Klamath Lake

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

Clearwater No. 1

Forebay for peaking

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

Clearwater No. 2

Forebay for peaking

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

Fish Creek

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1,

Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Grace

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2009 was $13,984,813: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.1 Line No.: -1 Column: d

Iron Gate

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.1 Line No.: -1 Column: e

JC Boyle

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.1 Line No.: -1 Column: f

Lemolo No. 1

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Fish Creek

Forebay for peaking

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

Iron Gate

Storage for regulation

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

JC Boyle

Pondage for peaking - storage, Upper Klamath Lake

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

Lemolo No. 1

Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: -1 Column: b

Lemolo No. 2

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.2 Line No.: -1 Column: c

Merwin

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2009 was $40,480,460: Merwin, Yale, and Swift #1.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.2 Line No.: -1 Column: d

Toketee

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.2 Line No.: -1 Column: e

Oneida

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2009 was $13,984,813: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.2 Line No.: -1 Column: f

Prospect No. 2

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement at Prospect units 1, 2, and 4 on December 31, 2009 was $7,245,959.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.2 Line No.: 1 Column: b

Lemolo No. 2

Storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: d

Toketee

Pondage for peaking - storage, Lemolo Lake

Schedule Page: 406.2 Line No.: 1 Column: f

Prospect No. 2

Forebay for peaking

Schedule Page: 406.3 Line No.: -1 Column: b

Slide Creek

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the

North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.3 Line No.: -1 Column: c

Soda

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Bear River system for the following projects at December 31, 2009 was $13,984,813: Grace, Oneida and Soda.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.3 Line No.: -1 Column: d

Soda Springs

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.3 Line No.: -1 Column: e

Swift #1

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2009 was $40,480,460: Merwin, Yale, and Swift #1.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.3 Line No.: -1 Column: f

Yale

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the Lewis River system for the following projects at December 31, 2009 was $40,480,460: Merwin, Yale, and Swift #1.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 406.4 Line No.: -1 Column: b

Olmsted

The Olmsted Plant is owned by the U.S. Bureau of Land Reclamation. PacifiCorp has a 25-year lease beginning in 1990. PacifiCorp operates the plant and owns all the generation. The cost of the Olmsted plant includes leasehold improvements and facilities which PacifiCorp holds title.

All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydroelectric : Licensed Proj. No.					
2	Ashton 2381	1917	6.85	6.6	33,735	8,901,803
3	Bend	1913	1.11	1.0	3,169	1,311,390
4	Big Fork 2652	1910	4.15	4.6	28,977	7,088,545
5	Cline Falls	1913	1.00			338,978
6	Condit 2342	1913	13.70	15.0	81,802	6,932,772
7	Eagle Point	1957	2.81	2.8	17,375	1,801,778
8	Eastside 2082	1924	3.20	3.0	7,656	1,992,974
9	Fall Creek 2082	1903	2.20	2.0	14,701	1,286,479
10	Fountain Green	1922	0.16	0.1	737	624,480
11	Granite	1896	2.00	1.2	7,339	5,002,434
12	Gunlock	1917	0.75	0.5	1,578	656,163
13	Last Chance	1983	1.73	1.3	4,034	2,802,691
14	Paris	1910	0.72	0.7	2,802	410,525
15	Pioneer 2722	1897	5.00	4.0	24,695	10,738,733
16	Powerdale 2659	1923	6.00			720,239
17	Prospect No. 1 2630	1912	3.76	4.6	29,008	1,033,321
18	Prospect No. 3 2337	1932	7.20	7.7	35,639	6,958,213
19	Prospect No. 4 2630	1944	1.00	0.9	2,379	357,755
20	Sand Cove	1926	0.80	0.5	1,297	891,596
21	Snake Creek	1910	1.18	1.0	3,588	1,019,558
22	Stairs 597	1895	1.00	1.2	6,477	1,596,871
23	St. Anthony 2381	1915	0.50			1,350,659
24	Veyo	1920	0.50	0.3	1,011	835,949
25	Viva Naughton	1986	0.74	0.3	851	1,195,939
26	Wallowa Falls 308	1921	1.10	1.0	6,656	2,834,145
27	Weber 1744	1911	3.85	2.0	15,154	2,889,714
28	West Side 2082	1908	0.60	0.6	1,066	468,574
29	Keno Regulating Dam 2082					7,501,154
30	Upper Klamath Lake 2082					5,063,528
31	North Umpqua 1927					14,147,981
32						
33	Pumping Plant:					
34	Lifton	1917	-4.50	-2.0	-1,300	19,296,114
35						
36	Wind:					
37	Foote Creek	1999	32.62	31.0	86,324	37,196,623
38	Glenrock	2008	99.00	99.0	253,875	199,803,708
39	Glenrock III	2009	39.00	38.0	84,675	87,151,990
40	Rolling Hills	2009	99.00	99.0	207,820	200,996,518
41	Goodnoe Hills	2008	94.00	93.0	237,374	179,757,749
42	Leaning Juniper 1	2006	100.50	100.0	258,767	174,191,781
43	Marengo	2007	140.40	138.0	316,552	236,868,467
44	Marengo II	2008	70.20	69.0	158,279	127,879,828
45	Seven Mile Hill	2008	99.00	99.0	303,510	198,738,782
46	Seven Mile Hill II	2008	19.50	19.0	62,229	41,775,232

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
1,299,533	402,667		107,524	Water		2
1,181,432	56,980		4,269	Water		3
1,708,083	322,169		57,962	Water		4
338,978	5,042		724	Water		5
506,042	397,378		66,475	Water		6
641,202	261,276		59,323	Water		7
622,804	139,871		7,852	Water		8
584,763	91,307		32,806	Water		9
3,903,000	25,098		-2,370	Water		10
2,501,217	120,769		18,084	Water		11
874,884	53,382		11,989	Water		12
1,620,053	129,615		14,966	Water		13
570,174	42,027		19,747	Water		14
2,147,747	282,186		140,023	Water		15
120,040	147,135		6,446	Water		16
274,819	168,736		-15,528	Water		17
966,418	401,256		111,224	Water		18
357,755	47,785		47,327	Water		19
1,114,495	52,688		14,391	Water		20
864,032	92,105		28,756	Water		21
1,596,871	91,149		10,153	Water		22
2,701,318	32,053		3,520	Water		23
1,671,898	49,900		70,407	Water		24
1,616,134	78,185		25,430	Water		25
2,576,495	41,145		31,364	Water		26
750,575	191,872		61,378	Water		27
780,957	50,400		21,780	Water		28
	3,377		8,159			29
	157,408		20,606			30
						31
						32
						33
-4,288,025	205,529		51,321	Water		34
						35
						36
1,140,301	1,630,021			Wind		37
2,018,219	1,313,119		92,496	Wind		38
2,234,666	432,263		21,909	Wind		39
2,030,268	1,901,925		55,616	Wind		40
1,912,316	1,913,858		57,490	Wind		41
1,733,252	2,677,232		63,356	Wind		42
1,687,097	4,826,041		87,866	Wind		43
1,821,650	2,039,396		43,933	Wind		44
2,007,462	1,339,535		118,755	Wind		45
2,142,320	274,818		23,991	Wind		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	04/14/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	High Plains	2009	99.00	98.0	72,695	219,244,704
2	McFadden Ridge I	2009	28.50	27.0	20,558	56,762,967
3						
4						
5						
6						
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8						
9						
10						
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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	04/14/2010	End of 2009/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
2,214,593	186,553		675,439	Wind		1
1,991,683	49,753		191,033	Wind		2
						3
						4
						5
						6
						7
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FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: a

Common river system costs for the operation of these facilities are allocated to each plant based upon the unit's name plate rating.

Schedule Page: 410 Line No.: 2 Column: a

Ashton

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $337,638.

Schedule Page: 410 Line No.: 3 Column: a

Bend

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $178,000.

Schedule Page: 410 Line No.: 4 Column: a

Big Fork

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $547,892.

Schedule Page: 410 Line No.: 5 Column: a

Cline Falls

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 6 Column: a

Condit

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility 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 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal would not begin until October 2008, with a total cost to decommission not to exceed $21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp is in the process of acquiring all necessary permits within the terms and conditions of the amended settlement agreement. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin no earlier than October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. In January 2009, the study work was completed and the results were provided to the United States Army Corps of Engineers and the Washington Department of Ecology. In January 2010, the Washington Department of Ecology released the Final Second Supplemental Environmental Impact Statement which formally considered this additional information. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process within the second quarter of 2010. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

Schedule Page: 410 Line No.: 7 Column: a

Eagle Point

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 8 Column: a

Eastside

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 9 Column: a

Fall Creek

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 10 Column: a

Fountain Green

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $1,524.

Schedule Page: 410 Line No.: 11 Column: a

Granite

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 12 Column: a

Gunlock

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $44,303.

Schedule Page: 410 Line No.: 13 Column: a

Last Chance

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 14 Column: a

Paris

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 15 Column: a

Pioneer

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $114,855.

Schedule Page: 410 Line No.: 16 Column: a

Powerdale

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6-MW 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 dam and associated system features, which is subject to the FERC and other regulatory approvals, is projected to cost $6 million, excluding inflation. Plant shut down and removal was 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 plant; however, removal is still scheduled for 2010. Also in February 2007, PacifiCorp submitted a request to the FERC to allow PacifiCorp to defer the remaining net book value and any additional removal costs of this system as a regulatory asset. In May 2007, the FERC issued an order that approved PacifiCorp's proposed accounting entries, thereby allowing PacifiCorp to reclassify the net book value and the estimated removal costs to a regulatory asset. PacifiCorp has received approval from its state regulatory commissions to defer and recover these costs.

The remaining costs in column (f) represent land and equipment that will be transferred or sold after the plant is decommissioned.

Schedule Page: 410 Line No.: 17 Column: a

Prospect 1

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement at Prospect units 1, 2, and 4 at December 31, 2009 was $7,245,959.

Schedule Page: 410 Line No.: 18 Column: a

Prospect 3

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at Prospect unit number 3 at December 31, 2009 was $88,213.

Schedule Page: 410 Line No.: 19 Column: a

Prospect 4

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement at Prospect units 1, 2, and 4 at December 31, 2009 was $7,245,959.

Schedule Page: 410 Line No.: 20 Column: a

Sand Cove

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 21 Column: a

Snake Creek

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy

credits or other environmental commodities.

Schedule Page: 410 Line No.: 22 Column: a

Stairs

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $90,132.

Schedule Page: 410 Line No.: 23 Column: a

St. Anthony

Licensed Project No. 2381 applicable to both Ashton and St. Anthony plants.

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 24 Column: a

Veyo

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 25 Column: a

Viva Naughton

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 26 Column: a

Wallowa Falls

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 27 Column: a

Weber

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Costs reported for this plant do not include intangible costs due to relicensing which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing at December 31, 2009 was $321,557.

Schedule Page: 410 Line No.: 28 Column: a

West Side

All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 29 Column: a

1Keno Regulating Dam

Used in regulating the release of water from Klamath Lake and in maintaining proper water surface level in the Klamath River between Klamath Falls and Keno, Oregon.

Schedule Page: 410 Line No.: 30 Column: a

Upper Klamath Lake

Storage reservoir for six plants on the Klamath River (Copco No. 1, Copco No. 2, East Side, West Side, John C. Boyle, and Iron Gate).

Schedule Page: 410 Line No.: 31 Column: a

FOOTNOTE DATA

North Umpqua
Represents facilities that support the North Umpqua River system projects. All common roads, employee houses, control equipment, etc. are in this account.

Costs reported for this plant do not include significant intangible costs due to relicensing and settlement which are recorded in FERC account 302, Franchises and Consents, and are not reported on this page. The net book value for relicensing and settlement on the North Umpqua River system for the following projects at December 31, 2009 was $66,669,978: Lemolo 1, Lemolo 2, Clearwater 1, Clearwater 2, Toketee, Fish Creek, Soda Springs, Slide Creek and the North Umpqua Common Plant.

Schedule Page: 410 Line No.: 36 Column: a

This footnote applies to all wind-powered generating facilities. All or some of the renewable energy attributes associated with this generation may be (i) used in future years to comply with state or federal renewable portfolio standards or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 37 Column: a

Foote Creek
The Foote Creek wind-powered generating facility is operated by SeaWest Energy and is jointly owned. Data reported represents PacifiCorp's share. Ownership of the plant is as follows: PacifiCorp 78.79%, Eugene Water and Electric Board 21.21%.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	MALIN, OR	PG&E ROUND MTN, CA	500.00	500.00	Steel Tower	47.00		1
2	KLAMATH CO-GEN, OR	CAPTAIN JACK, OR	500.00	500.00	Steel Tower	26.00		1
3	MERIDIAN, OR	KLAMATH CO-GEN, OR	500.00	500.00	Steel Tower	58.00		1
4	ALVEY, OR	DIXONVILLE 500, OR	500.00	500.00	Steel Tower	58.00		1
5	DIXONVILLE, OR	MERIDIAN, OR	500.00	500.00	Steel Tower	74.00		1
6	CAPTAIN JACK, OR	MALIN, OR	500.00	500.00	Steel Tower	7.00		1
7	MIDPOINT, OR	MALIN, OR	500.00	500.00	Steel Tower	446.00		1
8	COLSTRIP 4, MT	SWITCHYARD, MT	500.00	500.00	Steel Tower	1.00		1
9	COLSTRIP, MT	BROADVIEW A, MT	500.00	500.00	Steel Tower	112.00		1
10	COLSTRIP, MT	BROADVIEW B, MT	500.00	500.00	Steel Tower	116.00		1
11	BROADVIEW, MT	TOWNSEND A, MT	500.00	500.00	Steel Tower	133.00		1
12	BROADVIEW, MT	TOWNSEND B, MT	500.00	500.00	Steel Tower	133.00		1
13	500 kV costs and expenses							
14								
15	Subtotal 500 kV					1,211.00		12
16								
17	BEN LOMOND, UT	BORAH, ID	345.00	345.00	Wood - H	133.00		1
18	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel SP	70.00		1
19	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00			47.00	1
20	EMERY, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel Tower	121.00		1
21	CAMP WILLIAMS, UT	MONA #3, UT	345.00	345.00	Wood - H	47.00		1
22	NINETY SOUTH, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel SP		11.00	1
23	CAMP WILLIAMS, UT	MONA #1, UT	345.00	345.00	Wood - H	47.00		1
24	CAMP WILLIAMS, UT	MONA #2, UT	345.00	345.00	Steel Tower	47.00		1
25	SPANISH FORK, UT	CAMP WILLIAMS, UT	345.00	345.00			35.00	1
26	TERMINAL, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel SP	26.00		1
27	TERMINAL, UT	CAMP WILLIAMS #2, UT	345.00	345.00			23.00	1
28	EMERY, UT	HUNTINGTON, UT	345.00	345.00	Wood - H	20.00		1
29	EMERY, UT	SIGURD #1, UT	345.00	345.00	Steel - H	74.00		1
30	EMERY, UT	SIGURD #2, UT	345.00	345.00	Steel - H	75.00		1
31	FOUR CORNERS, NM	PINTO, UT	345.00	345.00	Wood - H	101.00		1
32	GOSHEN, ID	KINPORT, ID	345.00	345.00	Wood - H	41.00		1
33	HUNTINGTON, UT	PINTO, UT	345.00	345.00	Wood - H	160.00		1
34	HUNTINGTON, UT	SPANISH FORK, UT	345.00	345.00	Wood - H	78.00		1
35	TERMINAL, UT	NINETY SOUTH, UT	345.00	345.00	Steel SP		16.00	1
36					TOTAL	15,802.00	648.00	240

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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
3-1852 ACSR 51/27								1
3-1272 ACSR 36/1								2
3-1272 ACSR 36/1								3
3-1272 ACSR 54/19								4
3-1272 ACSR 54/19								5
3-2250 AAC /91								6
3-1272 ACSR 36/1								7
								8
								9
								10
								11
								12
	13,734,190	269,584,360	283,318,550		976,000	374,982	1,350,982	13
								14
	13,734,190	269,584,360	283,318,550		976,000	374,982	1,350,982	15
								16
2-954 ACSR 54/7								17
2-1272 ACSR 45/7								18
2-1272 ACSR 45/7								19
2-1272 ACSR 45/7								20
2-954 ACSR 45/7								21
2-1272 ACSR 45/7								22
2-1272 ACSR 45/7								23
2-954 ACSR 54/7								24
2-1272 ACSR 45/7								25
2-1272 ACSR 45/7								26
2-1272 ACSR 45/7								27
2-954 ACSR 54/7								28
2-954 ACSR 54/7								29
2-954 ACSR 54/7								30
2-795 ACSR 45/7								31
2-795 ACSR 45/7								32
2-795 ACSR 45/7								33
2-1272 ACSR 45/7								34
2-1272 ACSR 45/7								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	MONA, UT	SIGURD #1, UT	345.00	345.00	Steel Tower	69.00		1
2	MONA, UT	SIGURD #2, UT	345.00	345.00			69.00	1
3	SIGURD, UT	UT / NV BORDER, UT	345.00	345.00	Wood - H	190.00		1
4	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	239.00		1
5	JIM BRIDGER, WY	KINPORT, ID	345.00	345.00	Steel Tower	234.00		1
6	MONA, UT	HUNTINGTON, UT	345.00	345.00	Steel Tower	60.00		1
7	CURRENT CREEK, UT	MONA, UT	345.00	345.00	Steel SP	1.00		1
8	CAMP WILLIAMS, UT	MONA #4, UT	345.00	345.00	Wood - H	5.00	42.00	1
9	345 kV costs and expenses							
10								
11	Subtotal 345 kV					1,838.00	243.00	27
12								
13	ANTELOPE, ID	ANACONDA, ID	230.00	230.00	Wood - H	76.00		1
14	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
15	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
16	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
17	BIRCH CREEK, UT	RAILROAD, UT	230.00	230.00	Wood - H	19.00		1
18	BEN LOMOND, UT	TERMINAL, UT	230.00	230.00	Steel Tower	47.00		1
19	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
20	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
21	GONDER (ELY), UT	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
22	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
23	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
24	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
25	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
26	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
27	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
28	GOOSE CREEK, WY	BUFFALO, WY	230.00	230.00	Wood - H	43.00		1
29	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
30	JIM BRIDGER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	218.00		1
31	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
32	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
33	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	32.00		1
34	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
35	DAVE JOHNSTON, WY	CASPER, WY	230.00	230.00	Wood - H	46.00		1
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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-795 ACSR 45/7								1
2-954 ACSR 54/7								2
2-954 ACSR 54/7								3
2-1272 ACSR 45/7								4
2-1272 ACSR 45/7								5
2-954 ACSR 54/7								6
2-954 ACSR 54/7								7
2-954 ACSR 54/7								8
	37,090,946	376,147,084	413,238,030	80,463	1,524,103	331,345	1,935,911	9
								10
	37,090,946	376,147,084	413,238,030	80,463	1,524,103	331,345	1,935,911	11
								12
1272 ACSR 45/7								13
795 ACSR 45/7								14
2-795 ACSR 26/7								15
2-795 ACSR 26/7								16
954 ACSR 54/7								17
1272 ACSR 45/7								18
795 ACSR 26/7								19
954 ACSR 45/7								20
795 ACSR 45/7								21
1272 ACSR 45/7								22
795 ACSR 45/7								23
795 ACSR 45/7								24
795 ACSR 45/7								25
1272 ACSR 36/1								26
1272 ACSR 36/1								27
795 ACSR 26/7								28
1272 ACSR 36/1								29
1272 ACSR 45/7								30
1272 ACSR 36/1								31
1272 ACSR 36/1								32
1272 ACSR 36/1								33
1272 ACSR 36/1								34
1272 ACSR 36/1								35
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	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
2	MONUMENT, WY	SHUTE CREEK, WY	230.00	230.00	Wood - H	13.00		1
3	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	50.00		1
4	ROCK SPRINGS, WY	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
5	YELLOWTAIL, MT	GOOSE CREEK, WY	230.00	230.00	Wood - H	59.00		1
6	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
7	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
8	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	119.00		1
9	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
10	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
11	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	30.00		1
12	CRAVEN CREEK, WY	NAUGHTON, WY	230.00	230.00	Wood - H	16.00		1
13	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
14	CHAPPEL CREEK, WY	CHIMNEY BUTTE, WY	230.00	230.00	Wood - H	14.00	6.00	1
15	MINERS, WY	FOOTE CREEK, WY	230.00	230.00	Wood - H	39.00		1
16	POINT OF ROCKS, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	27.00		1
17	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
18	YAMSAY, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
19	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
20	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
21	LONE PINE, OR	MERIDIAN, OR	230.00	230.00			5.00	1
22	GRANTS PASS, OR	DIXONVILLE LINE 72, OR	230.00	230.00	Wood - H	62.00		1
23	DIXONVILLE, OR	RESTON BPA, OR	230.00	230.00	Wood - H	17.00		1
24	TAP TO HANNA, OR	HANNA BPA, OR	230.00	230.00	Wood - H	9.00		1
25	DIXONVILLE 500, OR	DIXONVILLE 230, OR	230.00	230.00	Wood - H	1.00		1
26	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
27	MERIDIAN, OR	LONE PINE, OR	230.00	230.00	Steel SP	5.00		1
28	FAIRVIEW BPA, OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
29	TROUTDALE BPA, OR	PGE GRESHAM, OR	230.00	230.00	Steel Tower	6.00		1
30	TROUTDALE BPA, OR	LINNEMAN, OR	230.00	230.00	Steel Tower	6.00		1
31	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
32	SWIFT No. 2, WA	WOODLAND BPA SS, WA	230.00	230.00	Wood - H	23.00		1
33	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
34	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
35	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
36					TOTAL	15,802.00	648.00	240

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 36/1								1
1272 ACSR 36/1								2
1272 ACSR 45/7								3
1272 ACSR 36/1								4
795 ACSR 26/7								5
1272 ACSR 36/1								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
1272 ACSR 36/1								9
1272 ACSR 36/1								10
954 ACSR 54/7								11
954 ACSR 54/7								12
1272 ACSR 45/7								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
1272 ACSR 36/1								16
1272 ACSR 45/7								17
795 ACSR 26/7								18
1272 ACSR 36/1								19
795 ACSR 26/7								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
795 ACSR 26/7								23
795 ACSR 26/7								24
1272 ACSR 36/1								25
1272 ACSR 36/1								26
1272 ACSR 54/19								27
1272 ACSR 36/1								28
954 ACSR 45/7								29
900 ACSR 54/7								30
954 ACSR 45/7								31
954 ACSR 45/7								32
1272 ACSR 36/1								33
1272 ACSR 36/1								34
1272 ACSR 36/1								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
2	MCNARY BPA, WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
3	WALLA WALLA, WA	AVISTA LEWISTON, WA	230.00	230.00	Wood - H	45.00		1
4	WALLA WALLA, WA	WANAPUM, WA	230.00	230.00	Wood - H	33.00		1
5	TALBOT, WA	MARENGO, WA	230.00	230.00	Wood - H	8.00		1
6	UNION GAP, WA	MIDWAY BPA, WA	230.00	230.00	Wood - H	39.00		1
7	WANAPUM, WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
8	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
9	230 kV costs and expenses							
10								
11	Subtotal 230 kV					3,344.00	11.00	66
12								
13	ID / MT BORDER, ID	GOSHEN, ID	161.00	161.00	Wood - H		90.00	1
14	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
15	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood SP	9.00		1
16	EAGLEROCK, ID	SUGARMILL, ID	161.00	161.00	Wood SP	3.00		1
17	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
18	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
19	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood SP	17.00		1
20	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood SP	17.00		1
21	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	12.00		1
22	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
23	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood SP	18.00		1
24	161 kV costs and expenses							
25								
26	Subtotal 161 kV					255.00	90.00	11
27								
28	WHEELON, ID	AMERICAN FALLS, ID	138.00	138.00	Wood - H	86.00		1
29	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Wood - SP	21.00		1
30	OQUIRRH, UT	KCC BARNEY, UT	138.00	138.00	Wood - H	5.00		1
31	ANSCHTZ CO-GEN, WY	RAILROAD, WY	138.00	138.00	Wood - H	25.00		1
32	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
33	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
34	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	92.00		1
35	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
36					TOTAL	15,802.00	648.00	240

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR 36/1								1
1272 ACSR 36/1								2
1272 ACSR 36/1								3
1272 ACSR 36/1								4
795 ACSR 26/7								5
954 ACSR 45/7								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
	10,541,772	315,613,966	326,155,738	136,444	3,558,410	399,311	4,094,165	9
								10
	10,541,772	315,613,966	326,155,738	136,444	3,558,410	399,311	4,094,165	11
								12
250HH CU /7								13
397.5 ACSR 26/7								14
954 ACSR 45/7								15
954 ACSR 45/7								16
250HH CU /7								17
397.5 ACSR 26/7								18
397.5 ACSR 26/7								19
397.5 ACSR 26/7								20
1272 ACSR 45/7								21
556.5 ACSR 26/7								22
397.5 ACSR 26/7								23
	623,490	15,133,015	15,756,505		330,601	9,563	340,164	24
								25
	623,490	15,133,015	15,756,505		330,601	9,563	340,164	26
								27
250 CUHD /12								28
795 ACSR 45/7								29
795 ACSR 26/7								30
795 ACSR 26/7								31
397.5 ACSR 26/7								32
397.5 ACSR 26/7								33
397.5 ACSR 26/7								34
397.5 ACSR 26/7								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	BEKER INDUST, ID	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
2	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
3	BEN LOMOND, UT	EL MONTE, UT	138.00	138.00	Wood - H	14.00		1
4	BEN LOMOND, UT	EL MONTE, UT	138.00	138.00	Wood - H	13.00		1
5	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00			22.00	1
6	BEN LOMOND, UT	CLINTON, UT	138.00	138.00			23.00	1
7	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Wood - SP	28.00		1
8	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
9	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
10	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
11	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
12	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
13	CARBON, UT	HELPER, UT	138.00	138.00	Wood - H	2.00		1
14	CARBON, UT	HELPER, UT	138.00	138.00	Wood - H	2.00		1
15	CARBON, UT	SPANISH FORK, UT	138.00	138.00	Steel Tower	54.00		1
16	CARBON, UT	SPANISH FORK, UT	138.00	138.00			52.00	1
17	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
18	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
19	THREEMILE KNOLL, ID	MONSANTO 1, ID	138.00	138.00	Wood - H	2.00		1
20	THREEMILE KNOLL, ID	MONSANTO 2, ID	138.00	138.00	Wood - SP	2.00		1
21	PAINTER, WY	CLEAR CREEK, WY	138.00	138.00	Wood - SP	5.00		1
22	COLUMBIA, WY	MOUNDS SWRK, UT	138.00	138.00	Wood - H	9.00		1
23	COTTONWOOD, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	6.00		1
24	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
25	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	29.00		1
26	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP	1.00		1
27	ENTERPRISE, UT	MIDDLETON, UT	138.00	138.00	Wood - H	17.00		1
28	WEST CEDAR, UT	ENTERPRISE VALLEY, UT	138.00	138.00	Wood - H	33.00		1
29	FRANKLIN, UT	SMITHFIELD, UT	138.00	138.00	Wood - SP	25.00		1
30	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
31	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
32	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
33	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
34	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
35	TRI-CITY, UT	AMERICAN FORK, UT	138.00	138.00	Steel - SP	10.00		1
36					TOTAL	15,802.00	648.00	240

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TRANSMISSION LINE STATISTICS (Continued)

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795 ACSR 26/7								1
397.5 ACSR 26/7								2
795 ACSR 45/7								3
795 ACSR 45/7								4
250 CUHD /12								5
795 ACSR 45/7								6
795 ACSR 45/7								7
795 AAC /37								8
250 CUHD /12								9
795 ACSR 26/7								10
397.5 ACSR 26/7								11
397.5 ACSR 26/7								12
954 ACSR 54/7								13
556.5 ACSR 26/7								14
4/0 COMP								15
795 ACSR 26/7								16
250 CUHD /12								17
1272 ACSR 45/7								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
795 ACSR 26/7								21
266.8 ACSR 26/7								22
795 AAC /37								23
795 AAC /37								24
397.5 ACSR 26/7								25
397.5 ACSR 26/7								26
1272 ACSR 45/7								27
397.5 ACSR 26/7								28
397.5 ACSR 26/7								29
795 ACSR 45/7								30
795 AAC /37								31
1272 ACSR 45/7								32
1272 AAC /61								33
								34
1272 ACSR 45/7								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

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TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - SP	44.00		1
2	ONEIDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
3	TREASURETON, ID	GRACE 103, ID	138.00	138.00	Steel Tower	25.00		1
4	TREASURETON, ID	GRACE 104, ID	138.00	138.00			25.00	1
5	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	37.00		1
6	NINETY SOUTH, UT	HALE, UT	138.00	138.00	Wood - H	42.00		1
7	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - SP	23.00		1
8	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
9	MOUNDS SWRK, UT	HELPER, UT	138.00	138.00	Wood - H	29.00		1
10	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
11	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
12	TERMINAL, UT	KENNECOTT, UT	138.00	138.00			9.00	1
13	KILN, UT	NEBO, UT	138.00	138.00	Wood - H	30.00		1
14	MCCLELLAND, UT	MIDVALLEY, UT	138.00	138.00	Wood - SP	6.00		1
15	MOUNDS SWRK, UT	MOAB, UT	138.00	138.00	Wood - H	80.00		1
16	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
17	NAUGHTON, WY	NGPL, WY	138.00	138.00	Wood - H	35.00		1
18	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	46.00		1
19	NGPL, WY	TAP TO STR 204, WY	138.00	138.00	Wood - H	12.00		1
20	NINETY SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
21	TAYLORSVILLE, UT	NINETY SOUTH, UT	138.00	138.00	Wood - SP	7.00		1
22	MID VALLEY, UT	NINETY SOUTH, UT	138.00	138.00	Wood - H	9.00		1
23	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	10.00		1
24	ONEIDA, ID	OVID, ID	138.00	138.00	Wood - H	23.00		1
25	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
26	PAINTER, WY	RAILROAD, WY	138.00	138.00	Wood - H	7.00		1
27	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
28	TAP TO ANGEL SOUTH, UT	TAP TO PARRISH, UT	138.00	138.00			13.00	1
29	PARRISH, UT	TERMINAL, UT	138.00	138.00	Steel SP	16.00		1
30	PARRISH, UT	TERMINAL, UT	138.00	138.00			14.00	1
31	RAILROAD, WY	WHITNEY, WY	138.00	138.00	Wood - H	17.00		1
32	BEN LOMOND, UT	SYRACUSE, UT	138.00	230.00			25.00	1
33	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	56.00		1
34	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
35	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
36					TOTAL	15,802.00	648.00	240

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 ACSR 26/7								1
250 CUHD /12								2
250 CUHD /12								3
250 CUHD /12								4
1272 ACSR 45/7								5
1272 ACSR 45/7								6
1272 ACSR 45/7								7
1272 ACSR 45/7								8
397.5 ACSR 26/7								9
250 CUHD /12								10
397.5 ACSR 26/7								11
795 ACSR 26/7								12
397.5 ACSR 26/7								13
795 ACSR 26/7								14
397.5 ACSR 26/7								15
397.5 ACSR 26/7								16
795 ACSR 26/7								17
1272 ACSR 45/7								18
795 ACSR 26/7								19
1020 ACCC/TW								20
795 AAC /37								21
1272 ACSR 45/7								22
795 ACSR 45/7								23
336.4 ACSR 26/7								24
250 CUHD /12								25
1272 ACSR 45/7								26
397.5 ACSR 26/7								27
795 AAC /37								28
795 ACSR 45/7								29
795 ACSR 26/7								30
795 ACSR 26/7								31
795 AAC /37								32
795 AAC /37								33
336.4 ACSR 26/7								34
1272 ACSR 45/7								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00			13.00	1
2	TERMINAL, UT	MIDVALLEY, UT	138.00	138.00	Wood - H	7.00		1
3	TERMINAL, UT	CENT / MIDVALLEY, UT	138.00	138.00	Steel - SP	7.00		1
4	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	35.00		1
5	WHEELON #103, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
6	WHEELON #104, UT	TREASURETON, ID	138.00	138.00			29.00	1
7	WHEELON #105, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
8	KCC BARNEY, UT	KCCGRIND, UT	138.00	138.00	Wood - H	1.00		1
9	TERMINAL, UT	LAKE PARK, UT	138.00	138.00	Wood - H	14.00		1
10	OQUIRRH, UT	KCC BINGHAM, UT	138.00	138.00	Wood - H	8.00		1
11	WEST CEDAR, UT	COMMERCE, UT	138.00	138.00	Wood - SP	13.00		1
12	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
13	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	5.00		1
14	PARRISH, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
15	JERUSALM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
16	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
17	DIMPLE DELL, UT	DUMAS, UT	138.00	138.00	U/G	4.00		1
18	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
19	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP	1.00		1
20	MID VALLEY, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
21	NINETY SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
22	MICRON, UT	CAMP WILLIAMS, UT	138.00	138.00			9.00	1
23	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
24	NINETY SOUTH, UT	QUARRY SUBSTATION, UT	138.00	138.00	Wood - SP	8.00		1
25	90th S. QUARRY TAP, UT	DIMPLE DELL SUB, UT	138.00	138.00	U/G	2.00		1
26	EL MONTE, UT	STR 30B, UT	138.00	138.00	Steel - SP	4.00		1
27	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
28	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	1.00		1
29	MID VALLEY, UT	COTTONWOOD, UT	138.00	138.00	Steel - SP	5.00		1
30	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
31	BUTLERVILLE, UT	NINETY SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
32	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	2.00		1
33	SILVER CREEK SUB, UT	JORDANELLE SUB, UT	138.00	138.00	Steel - SP	10.00		1
34	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
35	RIVERDALE, UT	105 TAP, UT	138.00	138.00	Steel - SP	21.00		1
36					TOTAL	15,802.00	648.00	240

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 AAC /37								1
1272 ACSR 45/7								2
1272 AAC /61								3
4/0 ACSR 6/1								4
250 CUHD /12								5
250 CUHD /12								6
250 CUHD /12								7
795 ACSR 26/7								8
1557.4 ACSR/TW								9
397.5 ACSR 26/7								10
795 ACSR 26/7								11
1272 ACSR 45/7								12
1272 AAC /61								13
795 ACSR 45/7								14
397.5 ACSR 26/7								15
397.5 ACSR 26/7								16
1750 KCMIL								17
397.5 ACSR 26/7								18
1272 AAC /61								19
1557.4 ACSR/TW								20
795 AAC /37								21
795 ACSR 26/7								22
795 ACSR 26/7								23
795 AAC /37								24
1750 KCMIL								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
1557.4 ACSR/TW								29
795 ACSR 26/7								30
795 AAC /37								31
795 ACSR 26/7								32
795 ACSR 26/7								33
1557.4 ACSR/TW								34
795 ACSR 26/7								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	OQUIRRH, UT	SUNRISE / TRI-CITY, UT	138.00	138.00	Steel - SP	25.00		1
2	OQUIRRH, UT	BANGERTER / TRI-CITY, UT	138.00	138.00			21.00	1
3	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			2.00	1
4	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
5	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
6	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
7	MIDDLETON, UT	ST. GEORGE, UT	138.00	138.00	Wood - H	1.00		1
8	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Steel - SP	16.00		1
9	SYRACUSE, UT	TERMINAL, UT	138.00	230.00			29.00	1
10	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	8.00		1
11	138 kV costs and expenses							
12								
13	Subtotal 138 kV					1,874.00	304.00	123
14								
15								
16	All 115 kV Lines		115.00	115.00	Wood & Steel	1,575.00		
17	All 69 kV Lines		69.00	59.00	Wood & Steel	3,000.00		
18	All 57 kV Lines		57.00	57.00	Wood & Steel	113.00		
19	All 46 kV Lines		46.00	46.00	Wood & Steel	2,592.00		
20								
21								
22								
23								
24								
25								
26								
27								
28								1
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	15,802.00	648.00	240

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1557.4 ACSR/TW								1
1557.4 ACSR/TW								2
2-795 ACSR 26/7								3
1557.4 ACSR/TW								4
2-795 ACSR 26/7								5
1557.4 ACSR/TW								6
397.5 ACSR 26/7								7
1272 ACSR 45/7								8
1272 ACSR 45/7								9
795 ACSR 26/7								10
	13,651,514	303,443,022	317,094,536	3,221	2,642,906	86,609	2,732,736	11
								12
	13,651,514	303,443,022	317,094,536	3,221	2,642,906	86,609	2,732,736	13
								14
								15
	3,791,222	143,054,067	146,845,289	12,181	4,437,152	247,707	4,697,040	16
	4,635,867	222,568,540	227,204,407	6,620	3,141,467	146,112	3,294,199	17
	44,010	9,745,287	9,789,297		48,602	1,865	50,467	18
	6,323,363	197,849,776	204,173,139	6,223	2,960,825	43,888	3,010,936	19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	90,436,374	1,853,139,117	1,943,575,491	245,152	19,620,066	1,641,382	21,506,600	36

Schedule Page: 422 Line No.: 4 Column: a

The Alvey - Dixonville 500kV line is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp 50.0%, the BPA 50.0%. Cost reported for this line reflects the respondent's 50.0% share. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 422 Line No.: 5 Column: a

The Dixonville - Meridian 500kV line is jointly owned by the respondent and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp 50.0%, the BPA 50.0%. Cost reported for this line reflects the respondent's 50.0% share. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 422 Line No.: 8 Column: a

The Colstrip 4 - Switchyard 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 9 Column: a

The Colstrip – Broadview A 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 10 Column: a

The Colstrip – Broadview B 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 6.8%, all others 93.2%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 11 Column: a

The Broadview – Townsend A 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 8.1%, all others 91.9%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422 Line No.: 12 Column: a

The Broadview – Townsend B 500kV line is jointly owned by the respondent, NorthWestern Corporation, Puget Sound Power & Light, Washington Water Power Company and Portland General Electric. Ownership of the line is as follows: PacifiCorp 8.1%, all others 91.9%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422.4 Line No.: 34 Column: i

1557.4 ACSR/TW 36/7

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	HERRIMAN TAP, UT	HERRIMAN SUB., UT	4.00	Steel - SP	21.00	1	1
2	CHAPPEL CREEK, WY	CHIMNEY BUTTE, WY	20.00	Wood - H	8.00	1	1
3	FOOTE CREEK, WY	HIGH PLAINS WIND, WY	10.00	Wood - H	8.00	1	1
4	WINDSTAR, WY	GLENROCK WIND, WY	13.00	Wood - H	8.00	1	1
5	HONEYVILLE, UT	LAMPO, UT	3.00	Steel - SP	17.00	1	2
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		50.00		62.00	5	6

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1557	ACSR	Vertical 10'	138	4,301,444	2,967,684	634,311		7,903,439	1
1272	ACSR	Horiz 19'-6"	230	87,807	3,448,330	2,063,707		5,599,844	2
1272	ACSR	Horiz 19'-6"	230	262,400	4,144,882	1,036,221		5,443,503	3
1272	ACSR	Horiz 19'-6"	230		6,244,714	3,254,395		9,499,109	4
1272	ACSR	Vertical 10'	138	163,187	650,529	544,638		1,358,354	5
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									42
									43
				4,814,838	17,456,139	7,533,272		29,804,249	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	California				
2	BELMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	BIG SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	CANBY #2	DISTRIBUTION-UNATTEN	69.00	2.40	
5	CASTELLA SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
6	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	DOG CREEK SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
8	DORRIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	FORT JONES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	GASQUET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	GREENHORN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	HAMBURG SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
13	HAPPY CAMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	HORNBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	INTERNATIONAL PAPER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
16	LAKE EARL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	LITTLE SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
18	LUCERNE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	MACDOEL SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	MCCLOUD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	MILLER REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MONTAGUE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MORRISON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
24	MOUNT SHASTA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	NEWELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NORTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	NORTHCREST SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	NUTGLADE SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
29	PATRICKS CREEK SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
30	PEREZ SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	REDWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SCOTT BAR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	SEIAD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	SHASTINA SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
35	SHOTGUN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SMITH RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SNOW BRUSH SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
38	SOUTH DUNSMUIR SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
39	TULELAKE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	TUNNEL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
25	1					2
6	1					3
1	3					4
2	3					5
4	3					6
	1					7
8	3					8
6	1					9
9	1					10
13	1					11
1	1					12
8	3					13
4	3					14
9	3					15
13	1					16
2	3					17
4	1					18
31	2					19
6	1					20
4	3					21
6	1					22
14	1					23
16	4					24
8	3					25
6	6					26
20	4					27
2	3					28
1	1					29
2	3					30
9	3					31
2	3					32
2	3					33
18	3					34
1	1					35
6	3					36
	3					37
2	3					38
20	1					39
6	6					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WALKER BRYAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	WEED SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	YUBA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	YUROK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	Total		3105.00	468.36	
6	Number of Substations- 43				
7					
8	ALTURAS	T/D-UNATTENDED	115.00	12.47	69.00
9	FALL CREEK HYDRO/SUB	T/D-UNATTENDED	69.00	2.30	
10	YREKA SUB	T/D-UNATTENDED	115.00	12.47	69.00
11	Total		299.00	27.24	138.00
12	Number of Substations- 3				
13					
14	AGER SUB	TRANSMISSION-ATTENDE	115.00	69.00	
15	COPCO #1 HYDRO PLANT	TRANSMISSION-ATTENDE	69.00	2.30	
16	COPCO #2 230 SUB	TRANSMISSION-ATTENDE	230.00	115.00	
17	COPCO #2 HYDRO PLANT	TRANSMISSION-ATTENDE	69.00	6.60	
18	COPCO #2 SUB	TRANSMISSION-ATTENDE	69.00	12.47	
19	CRAG VIEW SUB	TRANSMISSION-UNATTEN	115.00	69.00	
20	DEL NORTE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
21	IRON GATE HYDRO PLANT	TRANSMISSION-UNATTEN	69.00	6.60	
22	WEED JUNCTION SUB	TRANSMISSION-UNATTEN	115.00	69.00	
23	Total		966.00	418.97	
24	Number of Substations- 9				
25					
26	Idaho				
27	ALEXANDER	DISTRIBUTION-UNATTEN	46.00	12.47	
28	AMMON	DISTRIBUTION-UNATTEN	69.00	12.47	
29	ANDERSON	DISTRIBUTION-UNATTEN	69.00	12.47	
30	ARCO	DISTRIBUTION-UNATTEN	69.00	12.47	
31	ARIMO	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BANCROFT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	BELSON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	BERENICE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CAMAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CANYON CREEK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
37	CHESTERFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	CINDER BUTTE SUB	DISTRIBUTION-UNATTEN	161.00	12.47	
39	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
7	1					1
25	1					2
4	3					3
4	3					4
337	102					5
						6
						7
31	4					8
3	3					9
95	2					10
129	9					11
						12
						13
5	3					14
28	6	2				15
375	2					16
60	3	1				17
2	3					18
19	3					19
150	2					20
19	1					21
38	3					22
696	26	3				23
						24
						25
						26
4	1					27
14	1					28
20	1					29
6	1					30
8	1					31
4	1					32
13	1					33
11	1					34
14	1					35
20	1					36
5	1					37
30	1	1				38
5	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COVE SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
2	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	GRACE CITY SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
9	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	HOLBROOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
18	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
19	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
27	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	RUDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	SANDUNE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
38	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	SODA SUB	DISTRIBUTION-UNATTEN	138.00	7.20	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
21	4					1
5	1					2
13	1					3
14	1					4
14	1					5
3	1					6
6	1					7
5	1					8
14	1					9
9	1					10
3	1					11
6	1					12
9	1					13
4	1					14
20	1					15
3	1					16
22	1					17
14	1					18
3	1					19
5	1					20
3	1					21
11	1					22
20	1					23
5	1					24
8	1					25
14	1					26
20	1					27
20	1					28
13	1					29
2	1					30
20	1					31
33	2					32
9	1					33
8	1					34
7	1					35
40	2					36
20	1					37
20	1					38
20	1					39
22	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
14	Total		4301.00	898.93	
15	Number of Substations- 67				
16					
17	MALAD SUB	T/D-UNATTENDED	138.00	46.00	12.47
18	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
19	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
20	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
21	Total		437.00	116.94	93.94
22	Number of Substations- 4				
23					
24	GRACE HYDRO	TRANSMISSION-ATTENDE	138.00	46.00	6.60
25	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
26	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	
27	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	2.40	
28	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
29	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
30	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
31	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
32	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
33	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	46.00
34	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
35	LIFTON HYDRO	TRANSMISSION-UNATTEN	69.00	2.30	
36	ONEIDA SUB	TRANSMISSION-UNATTEN	138.00	12.50	
37	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
38	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
39	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
40	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
14	1					1
8	1					2
5	1					3
13	1					4
13	1					5
4	1					6
4	1					7
7	1					8
7	1					9
14	1					10
20	1					11
4	1					12
20	1					13
799	72	1				14
						15
						16
71	4	1				17
14	1					18
189	4					19
40	2					20
314	11	1				21
						22
						23
115	4					24
75	2	1				25
250	1					26
25	3					27
67	1					28
67	1					29
67	1					30
25	3					31
75	1					32
763	8	1				33
233	3					34
6	2					35
40	2					36
30	1					37
76	2					38
168	3					39
700	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	
2	Total		3128.00	1259.20	213.60
3	Number of Substations- 18				
4					
5	Oregon				
6	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
7	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
8	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
9	ALDERWOOD	DISTRIBUTION-UNATTEN	69.00	12.47	
10	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
11	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
12	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
13	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	BELKNAP	DISTRIBUTION-UNATTEN	69.00	12.47	
17	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
21	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
23	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
27	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
32	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CLINE FALLS HYDRO	DISTRIBUTION-UNATTEN	12.47	2.40	
39	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
40	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
533	2					1
3315	41	2				2
						3
						4
						5
5	1					6
30	6					7
25	1					8
25	1					9
5	1					10
9	1					11
8	3	1				12
11	3					13
25	1					14
6	1					15
40	2					16
2	3					17
32	2					18
8	3					19
3	1					20
8	3					21
25	1					22
50	2					23
13	1					24
34	2					25
40	2					26
34	2					27
20	1					28
13	1					29
9	3					30
20	1					31
45	2					32
25	1					33
5	3					34
25	1					35
80	2					36
45	2					37
1	3					38
20	1					39
1	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
2	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
3	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
6	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
7	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	CUTLER CITY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
11	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
13	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
14	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
16	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
17	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	EAST VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
20	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	GAZLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
28	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
29	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
33	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
34	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
35	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
9	2					1
55	2	1				2
20	1					3
40	2					4
5	1					5
25	2					6
20	1					7
25	1					8
13	1					9
2	3					10
25	1					11
50	2					12
75	3					13
13	1					14
50	2					15
7	1					16
13	1					17
45	2					18
20	1					19
19	2					20
13	1					21
25	1					22
21	4					23
5	3					24
20	1					25
8	3					26
25	2					27
5	1					28
13	1					29
11	3					30
6	1					31
20	1					32
45	2					33
1	4					34
25	1					35
20	1					36
8	3					37
13	1					38
6	3					39
40	2					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
10	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
11	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
12	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
15	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	LAKEVIEW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
26	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
29	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	MEDFORD	DISTRIBUTION-UNATTEN	69.00	12.47	
31	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
36	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
40	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
45	2					1
20	1					2
75	3					3
50	2					4
40	2					5
20	1					6
13	1					7
2	1					8
20	1					9
75	2					10
13	1					11
20	1					12
20	1					13
6	1	1				14
25	2					15
3	3					16
40	2					17
6	1					18
50	2					19
9	3					20
13	3					21
40	2					22
105	3					23
40	2					24
9	1					25
25	2					26
25	1					27
20	1					28
20	1					29
79	14					30
45	2					31
17	6					32
	1					33
6	3					34
2	3					35
100	4					36
14	1					37
9	1					38
4	1					39
9	1					40

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
6	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
8	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
14	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
15	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	RICH MANUFACTURING SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
17	RIDDLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
21	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
23	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	SAGE ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
28	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
32	SHEVLIN PARK	DISTRIBUTION-UNATTEN	69.00	12.50	
33	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
34	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
36	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
40	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
45	2					1
8	1					2
55	2					3
45	2					4
1	1	1				5
40	2					6
39	2					7
46	7	1				8
22	2					9
6	1					10
50	2					11
11	3					12
50	2					13
2	3					14
50	2					15
8	1					16
14	1					17
25	1					18
25	2					19
50	2					20
9	3					21
25	1					22
9	1					23
9	1					24
45	2					25
40	2					26
70	3					27
8	1					28
40	2					29
9	1					30
2	3					31
25	1					32
19	2					33
9	1					34
20	1					35
7	3					36
40	2					37
55	2					38
	1					39
25	1					40

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
2	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
3	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	TALENT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
14	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
15	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
17	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
19	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
20	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	WESTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	WHITE CITY	DISTRIBUTION-UNATTEN	115.00	12.47	
25	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
26	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
28	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	Total		15476.54	2522.27	195.00
30	Number of Substations- 183				
31					
32	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
33	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
34	ASHLAND MTN AVE SUB	T/D-UNATTENDED	115.00	69.00	12.47
35	BEND PLANT	T/D-UNATTENDED	69.00	4.16	12.47
36	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
37	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
38	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
39	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
40	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
25	1					1
42	2					2
13	1					3
50	2					4
17	6					5
1	1					6
11	1					7
13	3					8
13	1					9
25	2					10
50	2					11
25	1					12
40	2					13
22	4					14
7	1					15
13	3					16
25	2					17
3	3					18
3	1					19
50	2					20
22	2					21
23	9					22
40	2					23
60	3					24
28	3					25
23	3					26
25	1					27
37	2					28
4506	365	5				29
						30
						31
177	9					32
65	2					33
70	2					34
23	3					35
70	2					36
132	4					37
187	8					38
39	4					39
400	4					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
2	Total		1219.00	399.04	338.82
3	Number of Substations- 10				
4					
5	CLEARWATER #1 HYDRO PLANT	TRANSMISSION-ATTENDE	138.00	6.90	
6	CLEARWATER #2 HYDRO PLANT	TRANSMISSION-ATTENDE	138.00	12.00	
7	FISH CREEK HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
8	JC BOYLE HYDRO	TRANSMISSION-ATTENDE	230.00	11.00	
9	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.30	12.50	
10	LEMOLO #2 HYDRO	TRANSMISSION-ATTENDE	115.00	12.00	
11	PROSPECT 1 HYDRO	TRANSMISSION-ATTENDE	69.00	2.30	
12	PROSPECT 2 HYDRO	TRANSMISSION-ATTENDE	69.00	6.60	
13	PROSPECT 3 HYDRO	TRANSMISSION-ATTENDE	69.00	12.47	
14	TOKETEE HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
15	BEND PLANT	TRANSMISSION-UNATTEN	4.16	2.40	
16	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
17	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
18	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
19	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
20	DAYS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
21	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
22	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
23	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
24	EAGLE POINT HYDRO	TRANSMISSION-UNATTEN	115.00	2.40	
25	EAST SIDE HYDRO	TRANSMISSION-UNATTEN	46.00	12.47	
26	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
27	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
28	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
29	GREEN SPRINGS PLANT/SUB	TRANSMISSION-UNATTEN	115.00	69.00	
30	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
31	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
32	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
33	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
34	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
35	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
36	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
37	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
38	POWERDALE PLANT	TRANSMISSION-UNATTEN	69.00	7.20	
39	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
40	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
75	5					1
1238	43					2
						3
						4
17	3					5
31	3					6
13	3					7
89	2	1				8
2	3	1				9
40	4					10
5	3					11
40	6	1				12
10	6					13
50	9					14
3	3					15
75	1					16
119	4					17
60	1					18
67	3					19
50	1					20
75	1					21
344	6					22
650	3	1				23
3	1					24
3	3					25
7	3					26
500	2					27
458	4					28
19	3					29
29	2					30
250	1					31
33	1					32
251	6	1				33
733	10					34
1300	6	1				35
50	1					36
250	1					37
8	3	1				38
47	4					39
50	1					40

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SLIDE CREEK HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
2	SODA SPRINGS HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
3	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
4	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
5	WALLOWA FALLS HYDRO	TRANSMISSION-UNATTEN	20.80		
6	Total		6648.26	2462.04	347.40
7	Number of Substations- 41				
8					
9	Utah				
10	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
11	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	ALTAVIEW	DISTRIBUTION-UNATTEN	46.00	12.47	
15	AMALGA	DISTRIBUTION-UNATTEN	46.00	12.47	
16	AMERICAN FORK	DISTRIBUTION-UNATTEN	138.00	12.47	
17	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
18	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
24	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BOX ELDER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	BRICKYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
31	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
34	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	CARBIDE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
39	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
21	3					1
13	3					2
500	3					3
100	2					4
2	3					5
6367	131	7				6
						7
						8
						9
30	1					10
30	1					11
13	1					12
30	1					13
45	2					14
11	1					15
30	1					16
1	1					17
3	1					18
50	1					19
17	2					20
2	1					21
11	1					22
2	3					23
1	3					24
9	1					25
4	1					26
14	1					27
14	1					28
9	1					29
26	2					30
6	1					31
60	3					32
11	3					33
9	1					34
13	1					35
1	1					36
20	1					37
3	1					38
6	1					39
30	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
2	CENTENNIAL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
5	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	CLEARFIELD SOUTH	DISTRIBUTION-UNATTEN	138.00	12.47	
11	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
16	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
18	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
21	CRESCENT JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
22	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	DECADE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
26	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
29	DESERET SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
30	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	DIXIE DEER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
33	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	DUMAS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
25	1					1
40	2					2
22	1					3
9	1					4
30	1					5
25	1					6
3	1					7
4	1					8
	3					9
60	2					10
50	2					11
4	1					12
20	2					13
30	1					14
106	4					15
1	3					16
30	1					17
3	1					18
2	3					19
30	1					20
1	1					21
22	1					22
30	1					23
42	1					24
60	2					25
55	2					26
6	1					27
48	3					28
2	1					29
4	1					30
60	2					31
2	1					32
23	2					33
60	2					34
30	1					35
6	1					36
60	2					37
20	1					38
19	2					39
5	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	FERRON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
12	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	FREEDOM SUBSTATION	DISTRIBUTION-UNATTEN	46.00	7.20	
17	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
21	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
22	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	GREEN RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	GROW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
27	GUNLOCK HYDRO	DISTRIBUTION-UNATTEN	34.50	2.30	
28	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	HAMILTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
30	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
33	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	HIAWATHA SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
36	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	HOGLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
3	1					1
2	1					2
3	3					3
25	1					4
14	1					5
10	1					6
3	1					7
30	1					8
1	2					9
5	1					10
6	1					11
30	1					12
4	1					13
2	1					14
2	1					15
	1					16
22	1					17
13	1					18
28	2	1				19
30	1					20
30	1					21
2	1					22
43	2					23
24	1					24
5	2					25
72	3					26
1	1					27
11	1					28
1	3					29
60	2					30
3	1					31
3	3					32
4	1					33
30	1					34
1	3					35
25	1					36
50	2					37
22	1					38
4	1					39
32	2					40

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
4	IRON SPRINGS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	IVINS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
7	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
8	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
16	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	LARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	LISBON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
27	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
28	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
29	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	MANILA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	MANTUA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
22	1					1
13	2					2
1	1					3
5	3					4
2	1					5
22	1					6
13	2					7
30	1					8
30	1					9
2	3					10
3	1					11
5	1					12
7	1					13
60	2					14
7	1					15
53	2					16
6	1					17
40	2					18
2	1					19
14	1					20
20	1					21
20	1					22
4	1					23
20	1					24
	1					25
1	1					26
20	1					27
1	3					28
4	1					29
13	1					30
30	1					31
22	1					32
2	1					33
14	1					34
20	1					35
2	3					36
9	1					37
6	1					38
20	1					39
42	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	MELLING SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
3	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
7	MILLVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
13	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MORTON COURT SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	NIBLEY SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
23	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
28	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
38	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	PARIETTE SUBSTATION	DISTRIBUTION-UNATTEN	69.00	24.90	
40	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
58	4					1
5	1					2
30	1					3
25	1					4
14	1					5
1	1					6
13	1					7
2	1					8
19	2					9
13	1					10
3	1					11
3	1					12
6	1					13
25	1					14
6	3					15
5	1					16
6	1					17
6	1					18
7	1					19
20	1					20
5	1					21
14	1					22
25	1					23
2	1					24
25	1					25
22	1					26
25	1					27
45	10					28
14	1					29
24	2					30
6	1					31
22	1					32
3	1					33
20	1					34
14	1					35
48	2					36
4	1					37
5	1					38
4	3					39
35	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
13	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
15	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
16	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
19	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
20	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
21	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
30	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
31	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
33	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
38	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
50	2					1
16	2					2
6	1					3
55	2					4
2	1					5
14	1					6
22	1					7
25	1					8
14	1					9
30	1					10
2	1					11
4	1					12
60	2					13
4	1					14
15	1					15
2	1					16
1	3					17
14	1					18
13	1					19
3	1					20
45	2					21
45	2					22
5	1					23
22	2					24
11	1					25
40	2					26
20	1					27
5	1					28
4	1					29
30	1					30
24	3					31
	3					32
11	1					33
60	2					34
30	1					35
1	3					36
	1					37
1	3					38
13	2					39
5	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
3	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
4	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	SOUTHEAST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
17	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
20	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	STAIRS SUB	DISTRIBUTION-UNATTEN	12.47	2.40	
22	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
30	THIRD WEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	THOMPSON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
33	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
34	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
35	TRI CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	UNIVERSITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
39	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
6	1					2
60	2					3
20	1					4
2	1					5
40	2					6
5	1					7
30	1					8
13	1					9
30	1					10
20	2					11
60	2					12
25	1					13
30	1					14
50	1					15
50	2					16
22	2					17
6	1					18
4	1					19
4	1					20
2	1					21
20	1					22
14	1					23
7	1					24
30	1					25
8	1					26
6	1					27
14	1					28
14	1					29
40	2					30
24	3					31
2	1					32
25	1					33
34	2					34
30	1					35
39	2					36
50	2					37
48	4					38
22	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	VEYO HYDRO	DISTRIBUTION-UNATTEN	34.50	2.40	
3	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
7	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
10	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	WELLINGTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
18	WESTFIELD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
26	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	Total		20652.77	3720.78	184.97
30	Number of Substations- 299				
31					
32	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
33	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
34	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
35	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
36	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
37	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
38	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
39	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
40	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
33	2					1
2	3					2
2	1					3
25	1					4
13	1					5
30	1					6
30	1					7
2	3					8
14	1					9
22	1					10
5	1					11
4	1					12
22	1					13
28	1					14
30	1					15
25	1					16
60	3					17
20	1					18
1	3					19
14	1					20
30	1					21
1	1					22
14	1					23
4	1					24
	1					25
6	1					26
20	1					27
2	1					28
5564	429	1				29
						30
						31
135	3					32
30	1					33
175	3					34
289	7					35
8	1					36
114	2					37
97	2					38
164	2					39
22	1					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
2	OQUIRRH SUB	T/D-UNATTENDED	138.00	46.00	12.47
3	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
4	PIONEER PLANT	T/D-UNATTENDED	138.00	2.30	46.00
5	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
6	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
7	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
8	SPHINX SUB	T/D-UNATTENDED	46.00	12.47	
9	SYRACUSE SUB	T/D-UNATTENDED	138.00	46.00	12.47
10	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
11	TERMINAL	T/D-UNATTENDED	345.00	12.47	46.00
12	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
13	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
14	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
15	Total		3197.00	645.47	459.17
16	Number of Substations- 23				
17					
18	BLUNDELL PLANT	TRANSMISSION-ATTENDE	46.00	12.47	
19	CARBON PLANT	TRANSMISSION-ATTENDE	138.00	13.80	
20	EMERY SUB	TRANSMISSION-ATTENDE	138.00	6.90	69.00
21	GADSBY PLANT	TRANSMISSION-ATTENDE	138.00	13.80	46.00
22	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
23	HUNTER PLANT	TRANSMISSION-ATTENDE	345.00	23.00	
24	HUNTINGTON PLANT	TRANSMISSION-ATTENDE	345.00	23.00	
25	90TH SOUTH SUB	TRANSMISSION-UNATTEN	345.00	138.00	
26	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
27	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
28	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
29	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
30	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
31	BOOKCLIFFS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
32	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
33	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
34	CARBON SUB	TRANSMISSION-UNATTEN	46.00	2.40	
35	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
36	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
37	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
38	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
39	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
40	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
340	4					1
135	3					2
97	2					3
51	7					4
180	3					5
34	4					6
100	2					7
3	4	3				8
600	5					9
358	4					10
1108	6	2				11
130	2					12
158	3					13
30	1					14
4358	72	5				15
						16
						17
25	1					18
225	5					19
783	13	1				20
568	17					21
318	2					22
1513	5	1				23
981	4					24
1538	6	1				25
67	1					26
133	2					27
100	1					28
1813	5					29
100	2					30
6	3	1				31
25	3					32
169	2					33
8	1					34
33	1					35
40	2					36
70	2					37
313	3					38
33	1					39
67	2					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
2	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
3	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
5	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
6	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
8	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
9	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
10	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
11	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
12	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
13	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
14	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
15	OLMSTED SUB	TRANSMISSION-UNATTEN	46.00	2.40	
16	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
17	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
18	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
19	RED BUTTE SUB	TRANSMISSION-UNATTEN	230.00	138.00	
20	SAND COVE HYDRO	TRANSMISSION-UNATTEN	34.50	2.40	
21	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
22	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
23	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
24	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
25	WEBER PLANT/SUB	TRANSMISSION-UNATTEN	46.00	2.30	
26	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
27	Total		8521.50	3089.24	761.91
28	Number of Substations- 49				
29					
30	Washington				
31	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
34	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
37	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
38	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	MILL CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	NACHES HYDRO	DISTRIBUTION-UNATTEN	115.00	12.47	

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SUBSTATIONS (Continued)

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
225	3					1
142	2					2
35	1					3
80	2					4
270	4					5
67	1					6
75	1					7
45	1					8
141	4					9
900	2					10
67	1					11
13	1					12
67	1					13
67	1					14
15	1					15
138	2					16
133	2					17
258	3					18
400	1					19
	1					20
1124	6					21
63	2					22
1017	5					23
100	3	1				24
7	1					25
131	2					26
14508	138	5				27
						28
						29
						30
25	1					31
45	2					32
117	6					33
25	1					34
23	2					35
25	4					36
56	2					37
50	2					38
45	2					39
20	1					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
13	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	Total		2990.00	382.43	107.66
22	Number of Substations- 30				
23					
24	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
25	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
26	Total		299.00	127.47	12.47
27	Number of Substations- 2				
28					
29	CONDIT PLANT	TRANSMISSION-ATTENDE	69.00	2.30	
30	MERWIN PLANT	TRANSMISSION-ATTENDE	115.00	13.20	
31	YALE PLANT	TRANSMISSION-ATTENDE	230.00	13.80	
32	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
33	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
34	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
35	SWIFT 1 PLANT	TRANSMISSION-UNATTEN	230.00	13.00	
36	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
38	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
39	Total		1909.00	594.30	7.20
40	Number of Substations- 10				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
42	2					1
45	2					2
50	2					3
28	3					4
9	1					5
40	2					6
20	2					7
51	4					8
45	2					9
25	1					10
45	2					11
29	2					12
50	2					13
6	1					14
25	1					15
9	1					16
45	2					17
25	2					18
22	2					19
45	2					20
1087	61					21
						22
						23
14	1					24
348	5					25
362	6					26
						27
						28
13	6	1				29
183	9	1				30
144	3	1				31
125	1					32
39	9					33
300	2					34
261	3	1				35
300	2					36
120	2					37
250	1					38
1735	38	4				39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1					
2	Wyoming				
3	AIR BASE	DISTRIBUTION-UNATTEN	12.47	2.40	
4	ANTELOPE MINE	DISTRIBUTION-UNATTEN	230.00	34.50	
5	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
6	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
7	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
8	BID MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
10	BLACKS FORK	DISTRIBUTION-UNATTEN	230.00	34.50	
11	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
12	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
14	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
15	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	
16	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
17	CHAPMAN SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
18	CHATHAM SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
19	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
20	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
21	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
22	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
23	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
25	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
27	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
28	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
29	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
30	ELK HORN SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
31	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	EVANS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	FARMERS UNION SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
35	FIREHOLE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
36	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
38	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
39	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
40	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
						2
1	3					3
25	1					4
13	1					5
2	1					6
25	1					7
7	1					8
8	1					9
150	2					10
73	4					11
25	1					12
2	3					13
2	3					14
2	6	1				15
13	1					16
4	1					17
	3					18
1	3					19
3	2					20
4	1					21
45	2					22
40	2					23
5	3					24
9	1					25
13	1					26
6	3					27
9	1					28
5	1					29
25	1					30
13	1					31
9	1					32
40	2					33
2	3					34
50	2					35
25	1					36
20	1					37
50	2					38
6	1					39
45	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
2	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
3	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
4	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
8	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
9	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
10	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
11	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
12	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
13	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
14	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
15	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
16	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
17	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
18	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
19	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
20	OPAL SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
21	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
22	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
23	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
24	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
25	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
26	POINT OF ROCKS SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
27	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
28	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
29	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
30	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
31	RED BUTTE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
34	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
35	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
37	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
38	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
39	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
40	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
3	4					1
25	1					2
20	1					3
3	1					4
6	1					5
25	1					6
10	1					7
3	3					8
2	3					9
25	2					10
50	2					11
25	1					12
13	1					13
20	1					14
4	3					15
13	1	1				16
1	3					17
5	1					18
	1					19
8	1					20
2	3					21
3	3					22
5	1					23
8	1					24
17	9	2				25
25	1					26
3	1					27
2	3					28
13	1					29
200	2					30
20	1					31
45	2					32
6	1					33
2	3					34
1	1					35
14	3	1				36
2	6					37
150	2					38
25	1					39
2	3					40

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
2	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
3	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
4	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
5	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
6	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	
7	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
8	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
9	WESTERN CLAY SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
10	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
11	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
12	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
13	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	Total		8000.21	1378.34	25.70
15	Number of Substations- 91				
16					
17	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
18	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
19	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
20	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
21	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
22	Total		874.00	127.17	55.30
23	Number of Substations- 5				
24					
25	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
26	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
27	JIM BRIDGER UNITS 1-4	TRANSMISSION-ATTENDE	345.00	22.00	
28	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	69.00	
29	WYODAK 230KV SUB	TRANSMISSION-ATTENDE	230.00	69.00	
30	WYODAK PLANT	TRANSMISSION-ATTENDE	230.00	22.00	
31	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
32	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
33	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
34	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
35	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
36	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
37	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
38	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
39	MINERS SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
40	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	

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SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
5	1					1
13	1					2
5	1					3
9	1					4
25	2					5
3	3					6
2	6					7
3	1					8
1	1					9
25	1					10
5	1					11
20	1	1				12
	1					13
1699	172	6				14
						15
						16
20	1					17
45	2	1				18
8	6					19
50	3					20
25	1					21
148	13	1				22
						23
						24
1358	17					25
1084	22					26
1122	2					27
1232	15	1				28
60	1					29
503	3	1				30
53	3					31
517	6					32
67	1					33
75	1					34
196	2					35
15	2					36
20	1					37
91	4					38
58	4	1				39
200	2					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
2	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
3	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
4	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
5	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
6	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
7	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	
8	Total		5083.00	1883.50	402.00
9	Number of Substations- 23				
10					
11	CALIFORNIA				
12	Distribution - 43				
13	T/D - 3				
14	Transmission - 9				
15					
16	IDAHO				
17	Distribution - 67				
18	T/D - 4				
19	Transmission - 18				
20					
21	OREGON				
22	Distribution -183				
23	T/D - 10				
24	Transmission - 41				
25					
26	UTAH				
27	Distribution -299				
28	T/D - 23				
29	Transmission - 49				
30					
31	WASHINGTON				
32	Distribution - 30				
33	T/D - 2				
34	Transmission - 10				
35					
36	WYOMING				
37	Distribution - 91				
38	T/D - 5				
39	Transmission - 23				
40					

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
65	2					1
165	4					2
400	1					3
50	2					4
22	1					5
175	2					6
100	1					7
7628	99	3				8
						9
						10
						11
337						12
129						13
696						14
						15
						16
799						17
314						18
3315						19
						20
						21
4506						22
1238						23
6367						24
						25
						26
5564						27
4358						28
14508						29
						30
						31
1087						32
362						33
1735						34
						35
						36
1699						37
148						38
7628						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ALL STATES				
2	Distribution - 713				
3	T/D - 47				
4	Transmission - 150				
5					
6					
7					
8					
9					
10					
11					
12					
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15					
16					
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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	04/14/2010	End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
						1
13992						2
6549						3
34249						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						40

FOOTNOTE DATA

Schedule Page: 426.9 Line No.: 23 Column: a

The Dixonville 500kV Substation is jointly owned by the respondent and the Bonneville Power Administration (the "BPA"). Ownership of the substation is as follows: PacifiCorp 50.0% and the BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 426.9 Line No.: 35 Column: a

The Meridian 500kV Substation is jointly owned by the respondent and the Bonneville Power Administration (the "BPA"). Ownership of the substation is as follows: PacifiCorp 50.0% and the BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and the BPA 42.0%.

Schedule Page: 426.23 Line No.: 26 Column: a

The Jim Bridger 345kV Substation is jointly owned by the respondent and Idaho Power Company. Ownership of the substation is as follow: PacifiCorp 66.7% and Idaho Power Company 33.3%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 66.7% and Idaho Power Company 33.3%.

Schedule Page: 426.23 Line No.: 29 Column: a

The Wyodak 230kV Substation is jointly owned by the respondent and Black Hills Power. Ownership of the substation is as follows: PacifiCorp 80.0% and Black Hills Power 20.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 80.0% and Black Hills Power 20.0%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/14/2010	End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Long-term coal transportation contracts	Burlington Northern	151	29,066,124
3	Right-of-way fees	Burlington Northern		24,872
4				
5	Consulting and labor services	MEHC and subsidiaries	930.2, 426.5, 107	9,000,000
6				
7	Residential real estate brokerage and relocation			
8	services	HomeServices		-786,589
9				
10	Natural gas transportation services	Kern River Gas	501, 547	3,310,174
11				
12	Captive property and liability insurance	MEHC Insurance Svcs.	924, 925	7,161,477
13				
14	Coal	Pacific Minerals, Inc.	151	116,190,987
15	Labor services	Pacific Minerals, Inc.	511, 232	200,802
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Labor and benefits services	MEHC and subsidiaries		1,407,418
22				
23	Labor and other services	Pacific Minerals, Inc.	501, 107	2,416,583
24	Management fee	Pacific Minerals, Inc.	557	1,205,173
25				
26				
27				
28				
29				
30				
31				
32				
33				
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41				
42				

FOOTNOTE DATA

Schedule Page: 429 Line No.: 2 Column:

This footnote applies to all occurrences of "Burlington Northern" on page 429: Complete name is Burlington Northern Santa Fe Corporation ("BNSF").

As of December 31, 2009, Berkshire Hathaway Inc., PacifiCorp's ultimate parent company, owned 22.5% of BNSF's outstanding common stock. On November 2, 2009, Berkshire Hathaway Inc. and BNSF entered into an agreement for Berkshire Hathaway Inc. to purchase the remaining outstanding common stock of BNSF.

Schedule Page: 429 Line No.: 2 Column:

Included in the coal transportation costs are amounts related to a jointly owned plant that are paid indirectly to BNSF.

Schedule Page: 429 Line No.: 3 Column:

Various expense accounts.

Schedule Page: 429 Line No.: 5 Column:

This footnote applies to all occurrences of "MEHC and subsidiaries" on page 429: Complete name is MidAmerican Energy Holdings Company ("MEHC"). PacifiCorp is an indirect subsidiary of MEHC.

Schedule Page: 429 Line No.: 5 Column:

A portion of the services provided by MEHC are billed based on allocation factors, which are generally based on the labor and assets of each of MEHC's subsidiaries.

Schedule Page: 429 Line No.: 8 Column:

Complete name is HomeServices of America, Inc., which is a majority owned subsidiary of MEHC.

Schedule Page: 429 Line No.: 8 Column:

Various expense accounts.

Schedule Page: 429 Line No.: 10 Column:

Complete name is Kern River Gas Transmission Company, which is an indirect wholly owned subsidiary of MEHC.

Schedule Page: 429 Line No.: 12 Column:

Complete name is MEHC Insurance Services Ltd.

Schedule Page: 429 Line No.: 14 Column:

This footnote applies to all occurrences of "Pacific Minerals, Inc." on page 429: Pacific Minerals, Inc. is a wholly owned subsidiary of PacifiCorp that holds a 66.67% ownership interest in Bridger Coal Company, a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company.

Schedule Page: 429 Line No.: 21 Column:

Various labor accounts.

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ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

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IDAHO PUBLIC UTILITIES COMMISSION

May 28, 2010

VIA OVERNIGHT DELIVERY

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

Attention: Jean D. Jewell
Commission Secretary

Re: Commission Annual Report 2009

Rocky Mountain Power, a division of PacifiCorp, hereby submits for filing an original and seven (7) copies of the Idaho Public Utilities Commission Annual Report 2009. PacifiCorp's annual FERC Form 1 was shipped for filing April 14, 2010.

It is respectively requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@PacifiCorp.com

By Fax: (503) 813-6060

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

Any informal inquiries may be directed to Ted Weston, Idaho Regulatory Manager at 801-220-2963.

Sincerely,

Jeffery K. Larsen /Tw

Jeffery K. Larsen
Vice President, Regulation

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM NO. 1
FOR
MULTI-STATE ELECTRIC COMPANIES

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3 - 6	Electric Operation and Maintenance Expenses
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8	Taxes, Other Than Income Taxes
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Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) X An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

STATE OF IDAHO STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	ACCOUNT *(a)*	(Ref) Page No. *(b)*	ELECTRIC UTILITY Current Year *(c)*	 Previous Year *(d)*
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	232,599,319	255,576,999
3	Operating Expenses			
4	Operation Expenses (401)	3-6	131,123,707	157,693,957
5	Maintenance Expenses (402)	3-6	20,753,478	20,302,529
6	Depreciation Expenses (403) (A)	7	23,075,971	22,141,858
7	Amort. & Depl. of Utility Plant (404-405)	7	1,552,773	2,155,279
8	Amort. of Utility Plant Acq. Adj (406)		278,175	318,186
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		280,737	336,221
10	Amort. of Conversion Expenses (407)		-	-
11	Taxes other Than Income Taxes (408.1) (B)	8	5,041,687	4,904,875
12	Income Taxes - Federal (409.1)		(10,134,445)	(4,773,615)
13	-Other (409.1)		(1,343,396)	(417,772)
14	Provision for Deferred Income Taxes (410.1)		45,893,908	30,632,497
15	Provision for Deferred Income Taxes - Cr. (411.1)		(18,372,660)	(14,829,314)
16	Investment Tax Credit Adj. - Net (411.4)		(190,629)	(219,739)
17	(Gains) from Disp. of Utility Plant (411.6)		-	-
18	Losses from Disp. of Utility Plant (411.7)		-	-
19	(Gains) from Emission Allowances		(215,192)	(315,306)
20	(Gains) Loss on Sale of Utility Plant		(51,349)	(103,876)
21	TOTAL Utility Operating Expenses *(Enter Total of Lines 4 thru 20)*		197,692,765	217,825,780
22	Net Utility Operating Income *(Enter Total of line 2 less 21)*		34,906,554	37,751,219

(A) Vehicle depreciation is charged to functional accounts.
(B) Payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) _X_ An Original (2) __ A resubmission	(Mo, Da, Yr) May 26, 2010	Dec. 31, 2009

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If increases or decreases from previous period (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote).
5. See page 108-109 of FERC Form No. 1, Important Changes During Period, for important new territory added and important rate increases or decreases.
6. For lines 2,4,5,6, and 7 see page 304 of FERC Form No. 1 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	Title of Account	OPERATING REVENUES		MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH	
		Amount for Year	Amount for Previous Year	Amount for Year	Amount for Previous Year	Number for Year	Number for Previous Year
	(a)	(a)	(c)	(d)	(e)	(f)	(g)
1	Sales of Electricity						
2	(440) Residential Sales	59,247,029	58,451,721	716,349	727,371	56,430	55,818
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial) (See Instr. 4)	30,434,244	26,869,031	434,993	398,426	8,082	7,937
5	Large (or Industrial) (See Instr. 4)	96,605,416	111,954,918	1,801,789	2,262,639	5,545	5,523
6	(444) Public Street and Highway Lighting	472,700	467,242	2,556	2,488	224	276
7	(445) Other Sales to Public Authorities	-	-	-	-	-	-
8	(446) Sales to Railroads and Railways	-	-	-	-	-	-
9	(448) Interdepartmental Sales	-	-	-	-	-	-
10	TOTAL Sales to Ultimate Consumers	186,759,389	197,742,912	2,955,687	3,390,924	70,281	69,554
11	(447) Sales for Resale	32,242,352	49,491,559	(a)	(a)	(a)	(a)
12	TOTAL Sales of Electricity	219,001,741	247,234,471	2,955,687	3,390,924	70,281	69,554
13	(Less) (449.1) Provision for Rate Refunds	-	-	-	-	-	-
14	TOTAL Revenue Net of Prov. For Refunds	219,001,741	247,234,471	2,955,687	3,390,924	70,281	69,554
15	Other Operating Revenues						
16	(450) Forfeited Discounts	411,342	458,582				
17	(451) Miscellaneous Service Revenues	170,394	161,100				
18	(453) Sale of Water and Water Power	617	1,533				
19	(454) Rent from Electric Property	746,286	808,980				
20	(455) Interdepartmental Rents	-	-				
21	(456) Other Electric Revenues	12,268,939	6,912,333				
22							
23	TOTAL Other Operating Revenues	13,597,578	8,342,528				
24	TOTAL Electric Operating Revenues	232,599,319	255,576,999				

(a) For a complete list of the number of customers and Megawatt hours sold on a total company basis see pages 310-311 of the 2009 FERC Form No. 1 - Sales for Resale.

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) X An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,086,939	1,266,099
5	(501) Fuel	35,154,665	40,122,749
6	(502) Steam Expenses	1,809,879	2,170,220
7	(503) Steam from Other Sources	204,218	217,429
8	(Less) (504) Steam Transferred - Cr.	-	-
9	(505) Electric Expenses	199,838	247,630
10	(506) Miscellaneous Steam Power Expenses	2,213,516	2,525,521
11	(507) Rents	22,869	16,334
12	TOTAL Operation (Enter Total of lines 4 thru 11)	40,691,924	46,565,982
13	Maintenance		
14	(510) Maintenance Supervision and Engineering	305,774	346,029
15	(511) Maintenance of Structures	1,160,095	1,440,505
16	(512) Maintenance of Boiler Plant	4,798,961	5,024,482
17	(513) Maintenance of Electric Plant	1,712,848	1,674,389
18	(514) Maintenance of Miscellaneous Steam Plant	648,040	735,467
19	TOTAL Maintenance (Enter Total of lines 14 thru 18)	8,625,718	9,220,872
20	TOTAL Power Production Expenses - Steam Power (Enter Total of lines 12 & 19)	49,317,642	55,786,854
21	B. Nuclear Power Generation		
22	Operation		
23	(517) Operation Supervision and Engineering	-	-
24	(518) Fuel	-	-
25	(519) Coolants and Water		-
26	(520) Steam Expenses	-	-
27	(521) Steam from Other Sources	-	-
28	(Less) (522) Steam Transferred - Cr.	-	-
29	(523) Electric Expenses	-	-
30	(524) Miscellaneous Nuclear Power Expenses	-	-
31	(525) Rents	-	-
32	TOTAL Operation (Enter Total of lines 23 thru 31)	-	-
33	Maintenance		
34	(528) Maintenance Supervision and Engineering	-	-
35	(529) Maintenance of Structures	-	-
36	(530) Maintenance of Reactor Plant Equipment	-	-
37	(531) Maintenance of Electric Plant	-	-
38	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
39	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
40	TOTAL Power Production Expenses - Nuclear Power (Enter Total of lines 32 & 39)	-	-
41	C. Hydraulic Power Generation		
42	Operation		
43	(535) Operation Supervision and Engineering	476,467	512,537
44	(536) Water for Power	14,733	17,502
45	(537) Hydraulic Expenses	178,632	237,533
46	(538) Electric Expenses	-	-
47	(539) Miscellaneous Hydraulic Power Generation Expenses	893,500	1,036,304
48	(540) Rents	9,313	8,202
49	TOTAL Operation (Enter Total of lines 43 thru 48)	1,572,645	1,812,078

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHC

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	4,283	156
53	(542) Maintenance of Structures	61,282	71,146
54	(543) Maintenance of Reservoirs, Dams, and Waterways	81,256	83,463
55	(544) Maintenance of Electric Plant	76,950	91,322
56	(545) Maintenance of Miscellaneous Hydraulic Plant	128,915	124,953
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	352,686	371,040
58	TOTAL Power Production Expenses - Hydraulic Power (Enter Total of lines 49 & 57)	1,925,331	2,183,118
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	16,092	12,686
62	(547) Fuel	26,647,050	30,518,527
63	(548) Generation Expenses	790,943	1,053,278
64	(549) Miscellaneous Other Power Generation Expenses	946,101	635,509
65	(550) Rents	94,492	408,480
66	TOTAL Operation (Enter Total of lines 61 thru 65)	28,494,678	32,628,480
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	-	-
69	(552) Maintenance of Structures	77,422	75,393
70	(553) Maintenance of Generation and Electric Plant	746,652	346,580
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	66,504	29,322
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	890,578	451,295
73	TOTAL Power Production Expenses - Other Power (Enter Total of lines 66 & 72)	29,385,256	33,079,775
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	25,479,413	45,333,059
76	(556) System Control and Load Dispatching	76,886	116,018
77	(557) Other Expenses [1]	5,364,703	7,644,461
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	30,921,002	53,093,538
79	TOTAL Power Production Expenses - (Enter Total of lines 20, 40, 58, 73 and 78)	111,549,231	144,143,285
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	309,104	453,452
83	(561) Load Dispatching	473,344	495,694
84	(562) Station Expenses	76,481	108,582
85	(563) Overhead Line Expenses	12,446	5,420
86	(564) Underground Line Expenses	-	-
87	(565) Transmission of Electricity by Others	5,954,869	7,060,389
88	(566) Miscellaneous Transmission Expenses	121,493	104,244
89	(567) Rents	84,121	47,772
90	TOTAL Operation (Enter Total of lines 82 thru 89)	7,031,858	8,275,553
91	Maintenance		
92	(568) Maintenance Supervision and Engineering	1,800	570
93	(569) Maintenance of Structures	206,145	239,765
94	(570) Maintenance of Station Equipment	535,580	644,177
95	(571) Maintenance of Overhead Lines	996,067	941,024
96	(572) Maintenance of Underground Lines	2,620	-
97	(573) Maintenance of Miscellaneous Transmission Plant	9,240	27,906
98	TOTAL Maintenance (Enter Total of lines 92 thru 97)	1,751,452	1,853,442
99	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	8,783,310	10,128,995
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering	945,046	894,939
103	(581) Load Dispatching	622,006	595,952

(1) The Idaho amounts in FERC account 557 are $2,505,779 for Current Year and $3,238,393 for Previous Year. However, these amounts have been increased by $2,858,925 for Current Year and $4,406,068 for Previous year because of the estimated impact of the embedded cost differentials on Idaho results.

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(582) Station Expenses	209,928	255,140
106	(583) Overhead Line Expenses	302,758	162,592
107	(584) Underground Line Expenses	-	-
108	(585) Street Lighting and Signal System Expenses	9,587	10,351
109	(586) Meter Expenses	305,876	397,340
110	(587) Customer Installations Expenses	448,940	709,324
111	(588) Miscellaneous Distribution Expenses	332,391	370,170
112	(589) Rents	31,021	27,195
113	TOTAL Operation (Enter Total of lines 102 thru 112)	3,207,553	3,423,003
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	383,076	302,779
116	(591) Maintenance of Structures	153,547	118,918
117	(592) Maintenance of Station Equipment	877,853	664,135
118	(593) Maintenance of Overhead Lines	5,157,927	4,533,920
119	(594) Maintenance of Underground Lines	733,133	646,670
120	(595) Maintenance of Line Transformers	50,037	52,059
121	(596) Maintenance of Street Lighting and Signal Systems	132,712	163,040
122	(597) Maintenance of Meters	347,618	317,714
123	(598) Maintenance of Miscellaneous Distribution Plant	112,223	86,051
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	7,948,126	6,885,286
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	11,155,679	10,308,289
126	4. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
127	Operation		
128	(901) Supervision	110,843	92,212
129	(902) Meter Reading Expenses	1,682,422	1,807,158
130	(903) Customer Records and Collection Expenses	2,226,934	2,155,564
131	(904) Uncollectible Accounts	472,261	303,856
132	(905) Miscellaneous Customer Accounts Expenses	9,391	8,556
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	4,501,851	4,367,346
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	11,106	9,619
137	(908) Customer Assistance Expenses	6,641,783	1,565,402
138	(909) Informational and Instructional Expenses	177,389	154,192
139	(910) Miscellaneous Customer Service and Informational Expenses	5,819	2,476
140	TOTAL Cust. Service and Informational Exp. (Enter Total of lines 136 thru 139)	6,836,097	1,731,689
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	-	-
145	(913) Advertising Expenses	-	-
146	(916) Miscellaneous Sales Expenses	-	-
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	-	-
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	4,940,778	1,953,895
151	(921) Office Supplies and Expense	593,038	700,062
152	(Less) (922) Administrative Expenses Transferred - Cr.	(1,322,151)	(1,208,446)
153	(923) Outside Services Employee	564,232	667,017
154	(924) Property Insurance	1,225,216	1,788,804
155	(925) Injuries and Damages	379,998	531,614
156	(926) Employee Pensions and Benefits	-	-
157			

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - IDAHO

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
157	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
158	(927) Franchise Requirements	-	-
159	(928) Regulatory Commission Expenses	647,365	543,491
160	(929) Duplicate Charges - Cr.	(174,852)	(223,706)
161	(930.1) General Advertising Expenses	-	-
162	(930.2) Miscellaneous General Expenses	744,714	741,466
163	(931) Rents	267,761	302,091
164	TOTAL Operation (Enter Total of lines 150 thru 163)	7,866,099	5,796,288
165	Maintenance		
166	(935) Maintenance of General Plant	1,184,918	1,520,594
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 & 166)	9,051,017	7,316,882
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79, 99, 125, 133, 140, 147, and 167)	151,877,185	177,996,486

SUMMARY OF ELECTRIC OPERATION AND MAINTENANCE EXPENSES - IDAHO

Line No.	Functional Classifications (a)	Operation (b)	Maintenance (c)	Total (d)
169	Power Production Expenses			
170	Electric Generation:			
171	Steam Power	40,691,924	8,625,718	**49,317,642**
172	Nuclear Power	-	-	**-**
173	Hydraulic -Conventional	1,572,645	352,686	**1,925,331**
174	Other Power Generation	28,494,678	890,578	**29,385,256**
175	Other Power Supply Expenses	30,921,002		**30,921,002**
176	Total Power Production Expenses	101,680,249	9,868,982	**111,549,231**
177	Transmission Expenses	7,031,858	1,751,452	**8,783,310**
178	Distribution Expenses	3,207,553	7,948,126	**11,155,679**
179	Customer Accounts Expenses	4,501,851		**4,501,851**
180	Customer Service and Informational Expenses	6,836,097		**6,836,097**
181	Sales Expenses	-		**-**
182	Adm. and General Expenses	7,866,099	1,184,918	**9,051,017**
183	Total Electric Operation and Maintenance Expenses	131,123,707	20,753,478	**151,877,185**

STATE OF IDAHO - ALLOCATED

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) _x_ An Original (2) ___ A resubmission	(Mo, Da, Yr) May 26, 2010	Dec. 31, 2009

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification	Depreciation Expense (Account 403) [A]	Amortization of Limited-Term Electric Plant (Acct. 404)	Amortization of Other Electric Plant (Acct. 405)	Total
	(a)	(b)	(c)	(d)	(e)
1	Intangible Plant		1,493,206		**1,493,206**
2	Steam Production Plant	5,571,210			**5,571,210**
3	Nuclear Production Plant	-			**-**
4	Hydraulic Production Plant - Conventional	784,381			**784,381**
5	Hydraulic Production Plant - Pumped Storage	-			**-**
6	Other Production Plant	4,921,190	2,385		**4,923,575**
7	Transmission Plant	3,192,949			**3,192,949**
8	Distribution Plant	6,682,658			**6,682,658**
9	General Plant	1,923,583	57,182		**1,980,765**
10	Common Plant - Electric				**-**
11	TOTAL	23,075,971	1,552,773	-	**24,628,744**

(A) Vehicle depreciation is charged to functional accounts.

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

STATE OF IDAHO - ALLOCATED TAXES, OTHER THAN INCOME TAXES ACCOUNT 408.1 (B)

	KIND OF TAX	AMOUNT
1	Property	4,463,130
2	Miscellaneous	578,557
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20	Total (Must agree with page 1, line 11.)	5,041,687

(B) Payroll taxes are charged to functional accounts, which is consistent with where labor is charged.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) _X_ An Original (2) __ A resubmission	May 26, 2010	Dec. 31, 2009

NON-UTILITILY PROPERTY (ACCOUNT 121)

	Location Description	Description	Beginning Balance (c)	Acquistion (d)	Retirement (e)	Transfer (f)	Balance at End of Year (g)
1	IDAHO FALLS POLE TREATING PLANT	Fee Land	54,317				54,317
2	MALAD PLANT SITE AND WATER RIGHTS	Land Rights	33				33
3	GEORGETOWN PLANT LAND (121)	Fee Land	110				110
4	LAVA DEVELOPMENT (121)	Land Rights	1,274				1,274
5	MENAN SUBSTATION SITE (121)	Fee Land	55				55
6	UCON SITE (121) - CATERCORNER TO UCON SUBSTATI	Fee Land	27				27
7	OLD DUBOIS SUBSTATION SITE	Fee Land	75				75
8	EAST RIVER SUBSTATION SITE (121)	Fee Land	13,742				13,742
9	NORTH MONTEVIEW SUBSTATION SITE (121)	Fee Land	328				328
10	MONTEVIEW SUBSTATION SITE (121)	Fee Land	618				618
11	MUD LAKE SERVICE CENTER	Fee Land	17,915				17,915
12	ARCO TRANSMISSION SUBSTATION AND OFFICE	Fee Land	1,740				1,740
13	ARCO TRANSMISSION SUBSTATION AND OFFICE	Structures	35,653				35,653
14	CARIBOU 138kV SUBSTATION	Fee Land	-		(7,183)	7,183	-
15	THREEMILE KNOLL SUBSTATION	Fee Land	26,058				26,058
16	Total Non-Utility Property		151,945	-	(7,183)	7,183	151,945

Name of Respondent PacifiCorp dba Rocky Mountain Power	This Report Is: (1) _X_ An Original (2) __ A resubmission	Date of Report (Mo, Da, Yr) May 26, 2010	Year of Report Dec. 31, 2009

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	**UTILITY PLANT**		
2	In Service		
3	Plant In Service (Classified)	951,922,513	955,902,116
4	Property Under Capital Lease [1]	-	-
5	Plant Purchased or Sold	7,762,964	8,791,718
6	Completed Construction not Classified	4,095,461	3,252,244
7	Experimental Plant Unclassified	-	-
8	Total (Enter Total of Lines 3 through 7)	963,780,938	967,946,078
9	Leased To Others	-	-
10	Held for Future Use	580,625	750,560
11	Construction Work In Process	91,972,627	67,820,539
12	Acquisition Adjustments	7,980,380	9,128,243
13	Total Utility Plant (Enter Total of Lines 8 through 12)	1,064,314,570	1,045,645,420
14	Accumulated Provision for Depreciation, Amortization & Depletion	367,926,958	389,746,293
15	Net Utility Plant (Enter Total of Line 13 less Line 14)	696,387,612	655,899,127
16	**DETAIL OF ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION AND DEPLETION**		
17	In Service		
18	Depreciation	343,017,043	363,401,052
19	Amortization/Depletion of Producing Natural Gas Land And Land Rights	-	-
20	Amortization of Underground Storage Land and Land Rights	-	-
21	Amortization of Other Utility Plant	20,158,701	21,228,818
22	Total In Service (Enter Total of Lines 18 through 21)	363,175,744	384,629,870
23	Leased To Others		
24	Depreciation	-	-
25	Amortization And Depletion	-	-
26	Total Leased to Others (Enter Total of Lines 24 and 25)	-	-
27	Held for Future Use		
28	Depreciation	-	-
29	Amortization	-	-
30	Total Held for Future Use (Enter Total of Lines 28 and 29)	-	-
31	Abandonment of Leases (Natural Gas)	-	-
32	Accumulated Provision for Asset Acquisition Adjustment	4,751,214	5,116,423
33	Total Accumulated Provisions (Should Agree With Line 14 above) (Enter Total of Lines 22, 26, 30, 31 and 32)	367,926,958	389,746,293
34			

(1) Capital leases are not included in rate base; they are charged to operating expense.

ELECTRIC PLANT IN SERVICE - STATE OF IDAHO (ALLOCATED)

(In addition to Account 101, Electric Plant In Service (Classified), this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

Line No.	Account (a)	Beginning Balance (b)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT		
2	(301) Organization	-	-
3	(302) Franchises and Consents	7,254,241	7,710,760
4	(303) Miscellaneous Intangible Plant	29,779,555	28,106,698
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	37,033,796	35,817,458
6	2. PRODUCTION PLANT		
7	A Steam Production Plant		
8	(310) Land and Land Rights	5,428,705	4,870,169
9	(311) Structures and Improvements	46,937,258	42,067,263
10	(312) Boiler Plant Equipment	168,618,554	155,381,489
11	(313) Engines and Engine Driven Generators	-	-
12	(314) Turbogenerator Units	45,180,197	41,644,648
13	(315) Accessory Electric Equipment	20,390,793	18,604,762
14	(316) Misc. Power Plant Equipment	1,515,785	1,417,423
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	288,071,292	263,985,754
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights	-	-
18	(321) Structures and Improvements	-	-
19	(322) Reactor Plant Equipment	-	-
20	(323) Turbogenerator Units	-	-
21	(324) Accessory Electric Equipment	-	-
22	(325) Misc. Power Plant Equipment	-	-
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	-	-
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	1,143,555	1,012,879
26	(331) Structures and Improvements	4,958,440	4,852,448
27	(332) Reservoirs, Dams, and Waterways	16,727,953	15,508,390
28	(333) Water Wheels, Turbines, and Generators	5,616,447	5,440,601
29	(334) Accessory Electric Equipment	2,768,451	2,824,176
30	(335) Misc. Power Plant Equipment	143,508	121,058
31	(336) Roads, Railroads, and Bridges	829,230	775,921
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	32,187,584	30,535,473
33	D. Other Production Plant		
34	(340) Land and Land Rights	1,250,990	1,143,789
35	(341) Structures and Improvements	6,419,904	6,669,510
36	(342) Fuel Holders, Products, and Accessories	536,054	496,431
37	(343) Prime Movers	73,560,400	99,032,854
38	(344) Generators	13,374,080	14,710,230
39	(345) Accessory Electric Equipment	7,296,653	9,249,857
40	(346) Misc. Power Plant Equipment	402,103	491,526
41	TOTAL Other Production Plant (Enter Total of lines 34 thru 40)	102,840,184	131,794,197
42	TOTAL Production Plant (Enter Total of lines 15, 23, 32, and 41)	423,099,060	426,315,424

ELECTRIC PLANT IN SERVICE (Continued) STATE OF IDAHO (ALLOCATED)			
Line No.	Account (a)	Beginning Balance (b)	Balance End of Year (g)
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	5,478,889	4,985,691
45	(352) Structures and Improvements	3,901,893	3,963,046
46	(353) Station Equipment	63,172,280	62,349,650
47	(354) Towers and Fixtures	24,823,566	22,318,694
48	(355) Poles and Fixtures	30,966,465	27,850,728
49	(356) Overhead Conductors and Devices	41,007,286	36,808,896
50	(357) Underground Conduit	188,356	163,000
51	(358) Underground Conductors and Devices	431,335	381,263
52	(359) Roads and Trails	665,647	581,508
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	170,635,717	159,402,476
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	1,255,542	1,295,303
56	(361) Structures and Improvements	1,151,317	1,493,953
57	(362) Station Equipment	26,123,899	26,448,680
58	(363) Storage Battery Equipment	-	-
59	(364) Poles, Towers, and Fixtures	56,159,120	59,208,069
60	(365) Overhead Conductors and Devices	32,973,127	33,561,563
61	(366) Underground Conduit	6,942,477	7,255,335
62	(367) Underground Conductors and Devices	22,642,301	23,436,444
63	(368) Line Transformers	62,062,240	64,719,406
64	(369) Services	25,683,819	27,232,773
65	(370) Meters	13,817,534	13,860,550
66	(371) Installations on Customer Premises	162,607	164,985
67	(372) Leased Property on Customer Premises	2,437	-
68	(373) Street Lighting and Signal Systems	592,483	600,185
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	249,568,903	259,277,246
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	555,588	527,617
72	(390) Structures and Improvements	16,306,746	15,692,289
73	(391) Office Furniture and Equipment	5,217,332	4,496,220
74	(392) Transportation Equipment	6,437,195	6,369,557
75	(393) Stores Equipment	867,042	801,723
76	(394) Tools, Shop and Garage Equipment	3,430,881	3,261,288
77	(395) Laboratory Equipment	2,041,070	1,911,683
78	(396) Power Operated Equipment	8,750,317	8,903,079
79	(397) Communication Equipment	14,367,405	13,185,206
80	(398) Miscellaneous Equipment	339,542	331,206
81	SUBTOTAL (Enter Total of lines 71 thru 80)	58,313,118	55,479,868
82	(399) Other Tangible Property	17,251,522	15,630,041
83	TOTAL General Plant (Enter Total of lines 81 thru 82)	75,564,640	71,109,909
84	TOTAL (Accounts 101)	955,902,116	951,922,513
85	(102) Electric Plant Purchased	8,791,718	7,762,964
86	Plant Sold	-	-
87	(103) Experimental Electric Plant Unclassified	-	-
88	(106) Plant Unclassified	3,252,244	4,095,461
89	TOTAL Electric Plant in Service	967,946,078	963,780,938

STATE OF IDAHO --ALLOCATED

Name of Respondent	This Report Is:	Date of Report	Year of Report
PacifiCorp dba Rocky Mountain Power	(1) _X_ An Original (2) __ A resubmission	(Mo, Da, Yr) May 26, 2010	Dec. 31, 2009

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 (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense clearing, if applicable.

Line No.	ACCOUNT (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)		8,560,903	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)		4,556,395	Electric
8	Transmission Plant (Estimated)		241,126	Electric
9	Distribution Plant (Estimated)		4,581,385	Electric
10	Assigned to - Other		2,955	Electric
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)		9,381,861	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)		17,942,764	