PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 30, 2012

VIA OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capital Street, N.E., Suite 215
Salem, Oregon 97301-2551

Attn: Judy Johnson

RE: PacifiCorp FERC Form No. 1 - Resubmission

Please find enclosed two copies of the Resubmission of PacifiCorp's annual FERC Form No. 1 report for the year ended December 31, 2011.

FERC recently issued an order requiring certain restatements and revisions in PacifiCorp's accounting practices for its wholly owned coal mining and management subsidiaries. Historically, these entities were consolidated and intercompany profits were eliminated. Under the requirements of the order, PacifiCorp is now required to account for these subsidiaries under the equity method and not eliminate profit on intercompany transactions. This resubmission reflects these changes.

Please direct any informal questions to Bryce Dalley, Director of Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith
Vice President, Regulation

Enclosure

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2011/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

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

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

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

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

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

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

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

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

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent PacifiCorp	02 Year/Period of Report End of 2011/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 825 N.E. Multnomah, Suite 1900, Portland, OR 97232	
05 Name of Contact Person Henry E. Lay	06 Title of Contact Person 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* (503) 813-6179	09 This Report Is (1) ☐ An Original (2) ☒ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 06/28/2012

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 Douglas K. Stuver 02 Title Senior VP & Chief Financial Officer	03 Signature Douglas K. Stuver Douglas K. Stuver	04 Date Signed *(Mo, Da, Yr)* 06/28/2012

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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

Schedule Page: 2 Line No.: 1 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 7 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 8 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 9 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 10 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 11 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 12 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 21 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 28 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 35 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 37 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 40 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 45 Column:
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 2 Line No.: 62 Column:
Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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

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 is a United States regulated, vertically integrated 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.

Amended in accordance with FERC Order No. AC11-132.

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) ☒ No

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.

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.(a)
MidAmerican Energy Holdings Company (100%)
PPW Holdings LLC (100% controlled by MidAmerican Energy Holdings Company)
PacifiCorp (100% of common stock held by PPW Holdings LLC)

(a) Berkshire Hathaway Inc. owns 89.8%, Walter Scott, Jr. (along with family members and related entities) owns 9.4% and Gregory E. Abel owns 0.8% of MEHC's common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Fossil Rock Fuels, LLC	Mining	100	
4	Glenrock Coal Company	Mining	100	
5	Interwest Mining Company	Management Services	100	
6	Pacific Minerals, Inc.	Management Services	100	
7	Bridger Coal Company	Mining	66.67	
8	PacifiCorp Environmental Remediation Company	Environmental Services	100	
9	PacifiCorp Investment Management, Inc.	Management Services	100	
10	Trapper Mining Inc.	Mining	21.40	
11	PacifiCorp Foundation	Non-profit foundation		
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Schedule Page: 103 Line No.: 1 Column: a

In May 2000, the assets of Centralia Mining Company were sold to TransAlta. The entity is no longer active.

Schedule Page: 103 Line No.: 2 Column: a

Energy West Mining Company provides coal-mining services to PacifiCorp utilizing PacifiCorp's assets. Energy West Mining Company's costs are fully absorbed by PacifiCorp.

Schedule Page: 103 Line No.: 3 Column: a

In June 2011, PacifiCorp formed a wholly owned subsidiary, Fossil Rock Fuels, LLC, to acquire certain coal reserve leases and ultimately provide coal-mining services to PacifiCorp.

Schedule Page: 103 Line No.: 4 Column: a

Glenrock Coal Company ceased mining operations in October 1999.

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

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: 103 Line No.: 9 Column: a

PacifiCorp Investment Management, Inc. previously performed management services for PacifiCorp Environmental Remediation Company and is 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%), PacifiCorp (21.40%) and Platte River Power Authority (19.93%).

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

The PacifiCorp Foundation is an independent non-profit foundation created by PacifiCorp in 1988. The PacifiCorp Foundation operates as the Rocky Mountain Power Foundation and the Pacific Power Foundation. Two of the PacifiCorp Foundation's five directors are also directors of PacifiCorp.

Schedule Page: 103 Line No.: 13 Column: a

In accordance with Federal Energy Regulatory Commission Docket No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method as of December 31, 2011. Refer to Important Changes During the Year for further information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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, 2011:		
2	Chairman of the Board of Directors		
3	and Chief Executive Officer	Gregory E. Abel	
4	Senior Vice President and Chief Financial Officer	Douglas K. Stuver	239,269
5	President and Chief Executive Officer,		
6	Rocky Mountain Power	A. Richard Walje	368,000
7	President and Chief Executive Officer, Pacific Power	R. Patrick Reiten	291,528
8	President and Chief Executive Officer, PacifiCorp Energy	Micheal G. Dunn	278,820
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			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

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, 2011, 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 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.: 3 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, 2011 (File No. 001-14881) for executive compensation information for Mr. Abel.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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, 2011:	
2	Gregory E. Abel	
3	(Chairman of the Board of Directors and CEO, PacifiCorp)	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
4	R. Patrick Reiten	
5	(President and CEO, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
6	A. Richard Walje	
7	(President and CEO, Rocky Mountain Power)	201 South Main, Suite 2300, Salt Lake City, Utah 84111
8	Douglas L. Anderson	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
9	Brent E. Gale	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
10	Patrick J. Goodman	666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309
11	Micheal G. Dunn	
12	(President and CEO, PacifiCorp Energy)	1407 West North Temple, Suite 320, Salt Lake City, Utah 84116
13	Mark C. Moench	
14	(SVP, General Counsel and Corporate Secretary, PacifiCorp)	201 South Main, Suite 2400, Salt Lake City, Utah 84111
15	Natalie L. Hocken	
16	(Vice President and General Counsel, Pacific Power)	825 NE Multnomah, Suite 2000, Portland, Oregon 97232
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

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

As of December 31, 2011, PacifiCorp has only one committee, a Compensation Committee, of which the sole member is Mr. Abel.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

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

Does the respondent have formula rates? ☒ Yes ☐ No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff Volume No. 11	ER11-3643
2		
3		
4		
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		
35		
36		
37		
38		
39		
40		
41		

Schedule Page: 106 Line No.: 1 Column: a

As a result of a 2007 multi-party settlement with the Federal Energy Regulatory Commission ("FERC") regarding long-term shared usage, coordinated operation and maintenance, and planning of certain 500-kilovolt transmission lines, PacifiCorp agreed to file a Federal Power Act Section 205 rate change filing for its system-wide transmission service rates no later than June 1, 2011. In May 2011, PacifiCorp filed its Federal Power Act Section 205 rate case seeking to modify its transmission and ancillary services rates and adopt a formula transmission rate. In August 2011, the FERC issued an order in Docket No. ER11-3643 accepting PacifiCorp's filing and allowing the proposed rates to become effective December 25, 2011, subject to refund. Billing at the new rates commenced in early 2012. The FERC established settlement proceedings to encourage the parties to reach agreement on final rates. If a settlement is not reached, hearings will be held before the FERC to arrive at final approved rates. Settlement discussions are underway with the parties to the case.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1					
2					
3					
4					
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					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Schedule Page: 1061 Line No.: 1 Column: a

PacifiCorp expects to file its first informational filing on June 1, 2012.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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
1				
2				
3				
4				
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				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

ITEM 1.

The following table includes new or modified franchise agreements. The fee represents either the fee attached to the franchise agreement, an associated tax or fee.

State	Effective Date	Expiration Date	Fee
California (1)			
None			
Idaho (2)			
Montpelier	05/12/2011	05/12/2046	-
Ammon	06/08/2011	06/08/2041	3.0%
Lewisville	10/18/2011	10/18/2046	2.0%
McCammon	10/18/2011	10/18/2046	3.0%
St. Anthony	10/18/2011	10/18/2021	1.0%
Oregon (3)			
Mosier	09/11/2011	08/25/2021	7.0%
Stayton	09/29/2011	10/06/2021	5.0%
Central Point	12/08/2011	12/08/2021	6.0%
Independence (4)	12/20/2011	03/30/2012	5.0%
Astoria (4)	12/22/2011	12/31/2012	3.5%
Warrenton	12/22/2011	Month-to-Month Extension	5.0%
Utah (2)			
Panguitch	03/08/2011	03/08/2031	2.0%
Holladay	03/14/2011	03/14/2036	6.0%
Wasatch County	04/25/2011	09/28/2035	-
Centerville	06/07/2011	12/31/2016	5.0%
Hideout	06/22/2011	06/22/2021	6.0%
North Salt Lake	08/24/2011	08/24/2016	6.0%
Tremonton	11/02/2011	11/02/2021	6.0%
Mantua	11/11/2011	11/11/2036	-
Washington (2)			
Dayton	02/21/2011	02/21/2021	6.0%
Yakima County	04/19/2011	04/19/2036	-
Wyoming (5)			
Lincoln County	06/22/2011	06/22/2036	-
Cowley	10/13/2011	10/13/2036	2.0%

(1) In California, franchise agreement fees are an expense to PacifiCorp and are embedded in rates.

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

(3) In Oregon, the first 3.5% of the franchise agreement fee 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.

(4) These franchise agreements represent extensions through the expiration date noted or until a new franchise agreement is granted.

(5) In Wyoming, the first 1.0% of the franchise agreement fee 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.

ITEM 2.

For information on the resubmission, refer to Note 2 of Notes to Financial Statements in this Form No. 1.

ITEM 3.

In July 2011, the FERC in Docket No. AC11-81-000 approved the journal entries required by the Uniform System of Accounts ("USofA") for the sale of undivided ownership interests in certain of PacifiCorp's transmission facilities to Black Hills Power, Inc. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold, and recorded the sale to the appropriate accounts. For further discussion, refer to Important Changes During the Quarter/Year, Item 3 of PacifiCorp's annual report on Form No. 1 for the year ended December 31, 2010.

In March 2011, PacifiCorp entered into an agreement for the sale of the Snake Creek hydroelectric generating facility with Heber Light & Power Company. The sale closed in September 2011 and was recorded in account 102, Electric plant purchased or sold. In February 2012, the FERC in Docket No. AC12-7-000 approved the journal entries required by the USofA for the sale. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold and recorded the sale to the appropriate accounts. Commission authorizations for the sale were as follows:

- Oregon Public Utility Commission ("OPUC") - Order No. 11-331, effective August 26, 2011.
- California Public Utilities Commission ("CPUC") - Advice Letter 439-E, effective July 28, 2011.
- Wyoming Public Service Commission ("WPSC") - Docket No. 20000-395-EA-11, effective July 8, 2011, pursuant to open meeting action taken on July 8, 2011.

ITEM 4.

None.

ITEM 5.

During the year ended December 31, 2011, PacifiCorp did not significantly increase or decrease its distribution territory. Refer to pages 424-425 of this Form No. 1 for additional information regarding transmission lines added or removed during the year.

ITEM 6.

Short-term Debt and Revolving Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had $688 million of short-term debt outstanding as of December 31, 2011 at a weighted-average interest rate of 0.5%. PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2011.

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 ("WUTC") - Docket No. UE-980404, dated April 8, 1998.
- Idaho Public Utilities Commission ("IPUC") - Case No. PAC-E-11-09, Order No. 32221, dated April 8, 2011, effective through April 30, 2016.
- FERC - Docket No. ES09-50-000, dated October 9, 2009, letter order effective January 1, 2010 through December 31, 2011.
- FERC - Docket No. ES11-51-000, dated November 29, 2011 and errata notice dated November 30, 2011, letter order effective January 1, 2012 through December 31, 2013.

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

Long-term Debt

In March 2012, PacifiCorp issued $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. The net proceeds were used for the redemption of certain tax-exempt bonds, repayment of short-term debt and general corporate purposes.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

In May 2011, PacifiCorp issued $400 million of its 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $850 million of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. State commission authorizations for the above issuances and future issuances 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 made scheduled repayments on long-term debt totaling $587 million during the year ended December 31, 2011.

As of December 31, 2011, PacifiCorp had $601 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $587 million plus interest. These letters of credit were fully available at December 31, 2011 and expire periodically through November 2012.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2011, PacifiCorp estimated it would be able to issue up to $8.2 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

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.

Common Shareholder's Equity

In January 2012, PacifiCorp declared a dividend of $50 million, which was paid to PPW Holdings LLC, a wholly owned subsidiary of MidAmerican Energy Holdings Company ("MEHC") and PacifiCorp's direct parent company, in February 2012.

In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in April 2011.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in February 2011.

ITEM 7.

None.

ITEM 8.

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

Unions Represented	% Increase (1)	Effective Date(s)	Estimated Annual Financial Impact (2)
IBEW 57 Power Delivery (UT, ID & WY)	1.6%	1/26/2011	1,321,959
IBEW 57 Power Supply (UT, ID & WY)	1.6%	1/26/2011	622,877
UWUA 197 (OR)	0.9%	5/26/2011	16,116
IBEW 57 Combustion Turbine (UT)	1.1%	5/26/2011	23,940
IBEW 57 Laramie (WY)	0.8%	6/26/2011	4,622
IBEW 125 (OR, WA)	0.4%	8/26/2011	106,572
IBEW 659 (OR, CA)	0.7%	8/26/2011	223,715
UWUA 127 (WY)	0.4%	9/26/2011	171,741
Total			$ 2,491,542

(1) This percentage increase represents the increase in wages from the effective date of the increase to the end of the calendar year as compared to the wage scale of the prior calendar year.

(2) 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.

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 impact 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 addition to the following discussion, refer to Note 13 of Notes to Financial Statements in this Form No. 1, which includes an update on the USA Power legal matter.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp 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 due to alleged market manipulation during the energy crisis. 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 for review and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. 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 July 2010, the Oregon Court of Appeals accepted judicial review.

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 OPUC-approved special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In April 2011, Wah Chang's claims were presented during a jury trial, and all claims, including the claim for punitive damages, were resolved in PacifiCorp's favor. Wah Chang did not appeal this outcome and the outcome had no impact on PacifiCorp's financial results.

ITEM 10.

In June 2011, PacifiCorp formed a wholly owned subsidiary, Fossil Rock Fuels, LLC ("Fossil Rock"), to acquire certain coal reserve leases and ultimately provide coal-mining services to PacifiCorp. In conjunction with this formation, PacifiCorp contributed $20 million to Fossil Rock in July 2011 to fund the acquisition of the coal reserve leases.

Refer to page 429, Transactions with Associated (Affiliated) Companies, in this Form No. 1 for additional information regarding related-party transactions.

There have been no officer, director or security holder transactions during the year ended December 31, 2011.

ITEM 11.

(Reserved)

ITEM 12.

For information regarding general regulation, rate proceedings, environmental laws and regulations, future generation and conservation, and collateral and contingent features, refer to PacifiCorp’s Annual Report on Form 10-K for the year ended December 31, 2011 filed with the United States Securities and Exchange Commission ("SEC").

ITEM 13.

PacifiCorp discloses information for its "named executive officers" consistent with Item 402 of Regulation S-K promulgated by the SEC in its Annual Report on Form 10-K. There have been no changes in officers or directors during the year ended December 31, 2011.

ITEM 14.

Not applicable.

Deloitte.

Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 S.W. Fifth Ave.
Portland, OR 97204-3642
USA

Tel: +1 503 222 1341
Fax: +1 503 224 2172
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

PacifiCorp
Portland, Oregon

We have audited the balance sheet — regulatory basis of PacifiCorp (the "Company") as of December 31, 2011, and the related statements of income — regulatory basis, retained earnings — regulatory basis, and cash flows — regulatory basis, for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form No. 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, 2011, and the results of its operations and its cash flows for the year then ended, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

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

June 28, 2012

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	23,014,228,731	22,017,833,818
3	Construction Work in Progress (107)	200-201	1,203,547,965	1,000,790,049
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		24,217,776,696	23,018,623,867
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	7,666,665,056	7,467,085,584
6	Net Utility Plant (Enter Total of line 4 less 5)		16,551,111,640	15,551,538,283
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)		16,551,111,640	15,551,538,283
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		15,445,648	16,174,139
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,917,757	1,214,176
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	240,956,268	211,124,799
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)		83,950,135	84,517,252
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		6,137,779	4,236,855
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		4,472,312	9,400,334
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		349,114,313	324,309,131
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		14,846,926	3,930,954
36	Special Deposits (132-134)		774,146	603,868
37	Working Fund (135)		1,520	1,720
38	Temporary Cash Investments (136)		7,244,794	463,002
39	Notes Receivable (141)		238,519	351,089
40	Customer Accounts Receivable (142)		373,179,154	352,691,649
41	Other Accounts Receivable (143)		59,610,652	58,359,149
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,722,762	7,517,126
43	Notes Receivable from Associated Companies (145)		13,897,305	1,983,253
44	Accounts Receivable from Assoc. Companies (146)		7,455,752	13,686,414
45	Fuel Stock (151)	227	236,891,214	188,493,087
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	196,564,767	186,406,158
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) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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)		113,503,388	392,882,811
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		26,887	6,674
60	Rents Receivable (172)		2,237,540	1,535,228
61	Accrued Utility Revenues (173)		236,917,500	205,559,000
62	Miscellaneous Current and Accrued Assets (174)		2,574,464	0
63	Derivative Instrument Assets (175)		15,812,193	123,801,642
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		4,472,312	9,400,334
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)		1,268,581,647	1,513,838,238
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		33,449,341	33,300,472
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	135,566
72	Other Regulatory Assets (182.3)	232	1,874,535,671	1,737,446,767
73	Prelim. Survey and Investigation Charges (Electric) (183)		3,115,357	2,895,724
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)		66,905	90,676
78	Miscellaneous Deferred Debits (186)	233	88,864,233	86,478,095
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)		9,676,901	11,446,745
82	Accumulated Deferred Income Taxes (190)	234	639,645,755	588,589,916
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,649,354,163	2,460,383,961
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		20,818,161,763	19,850,069,613

Schedule Page: 110 Line No.: 21 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 110 Line No.: 35 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 110 Line No.: 41 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 110 Line No.: 43 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 110 Line No.: 44 Column: d

Amended in accordance with FERC Order No. AC11-132.

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

As of December 31, 2011, Account 165 Prepayments included $67,080,728 of 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, 2010, Account 165 Prepayments included $344,671,476 of income taxes receivable from MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 110 Line No.: 78 Column: d

Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	end of 2011/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	40,733,100	40,733,100
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	1,102,229,981	1,102,229,981
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	41,284,560	41,284,560
11	Retained Earnings (215, 215.1, 216)	118-119	2,649,231,266	2,655,984,147
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	151,915,641	142,404,172
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)	-9,055,432	-6,961,899
16	Total Proprietary Capital (lines 2 through 15)		7,311,715,892	7,311,050,837
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,171,055,000	6,357,741,000
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)		30,127	32,845
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,072,302	14,381,234
24	Total Long-Term Debt (lines 18 through 23)		6,157,012,825	6,343,392,611
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		53,732,331	55,883,528
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,468,000	8,499,000
29	Accumulated Provision for Pensions and Benefits (228.3)		580,877,623	493,432,168
30	Accumulated Miscellaneous Operating Provisions (228.4)		38,369,540	39,321,210
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		66,449,954	399,481,536
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		123,312,479	105,328,750
35	Total Other Noncurrent Liabilities (lines 26 through 34)		868,209,927	1,101,946,192
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		688,527,000	36,000,000
38	Accounts Payable (232)		536,085,457	448,570,314
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		56,292,853	47,687,205
41	Customer Deposits (235)		36,226,196	39,611,243
42	Taxes Accrued (236)	262-263	52,714,616	48,501,673
43	Interest Accrued (237)		110,248,092	115,234,368
44	Dividends Declared (238)		512,462	512,462
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		17,536,762	16,433,946
48	Miscellaneous Current and Accrued Liabilities (242)		78,951,246	62,325,256
49	Obligations Under Capital Leases-Current (243)		2,156,201	1,369,860
50	Derivative Instrument Liabilities (244)		156,054,864	483,234,721
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		66,449,954	399,481,536
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)		1,668,855,795	899,999,512
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		25,692,158	18,492,298
57	Accumulated Deferred Investment Tax Credits (255)	266-267	38,010,268	41,949,428
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	220,954,063	51,231,025
60	Other Regulatory Liabilities (254)	278	111,258,519	59,611,213
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	164,676,925	11,642,708
63	Accum. Deferred Income Taxes-Other Property (282)		3,505,053,651	3,330,234,891
64	Accum. Deferred Income Taxes-Other (283)		746,721,740	680,518,898
65	Total Deferred Credits (lines 56 through 64)		4,812,367,324	4,193,680,461
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		20,818,161,763	19,850,069,613

Schedule Page: 112 Line No.: 11 Column: d

Refer to FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 12 Column: d

Refer to footnote for column (d) line 11.

Schedule Page: 112 Line No.: 29 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 30 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 38 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 40 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 42 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 47 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 48 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 112 Line No.: 59 Column: d

Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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	4,553,757,373	4,402,215,385		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,304,873,210	2,300,047,532		
5	Maintenance Expenses (402)	320-323	432,482,383	414,960,789		
6	Depreciation Expense (403)	336-337	544,830,198	501,224,256		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	42,204,359	34,838,293		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,523,970	5,518,393		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		135,566	4,523,779		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,612,926	-2,004,224		
13	(Less) Regulatory Credits (407.4)		380,507			
14	Taxes Other Than Income Taxes (408.1)	262-263	151,699,035	136,550,272		
15	Income Taxes - Federal (409.1)	262-263	-138,818,714	-523,332,302		
16	- Other (409.1)	262-263	-7,862,714	-4,449,586		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	782,981,862	1,254,766,756		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	424,304,774	551,088,560		
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)		164,750	2,817,551		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		14,646	96,470		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,692,952,492	3,566,960,113		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		860,804,881	835,255,272		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
4,553,757,373	4,402,215,385					2
						3
2,304,873,210	2,300,047,532					4
432,482,383	414,960,789					5
544,830,198	501,224,256					6
						7
42,204,359	34,838,293					8
5,523,970	5,518,393					9
135,566	4,523,779					10
						11
1,612,926	-2,004,224					12
380,507						13
151,699,035	136,550,272					14
-138,818,714	-523,332,302					15
-7,862,714	-4,449,586					16
782,981,862	1,254,766,756					17
424,304,774	551,088,560					18
-1,874,204	-1,874,204					19
						20
						21
164,750	2,817,551					22
						23
14,646	96,470					24
3,692,952,492	3,566,960,113					25
860,804,881	835,255,272					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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)		860,804,881	835,255,272		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,731,641	1,416,581		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,055,446	1,362,155		
33	Revenues From Nonutility Operations (417)		43,686	247,917		
34	(Less) Expenses of Nonutility Operations (417.1)		110,939	81,037		
35	Nonoperating Rental Income (418)		172,282	91,251		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	9,511,469	15,252,746		
37	Interest and Dividend Income (419)		6,005,324	5,077,391		
38	Allowance for Other Funds Used During Construction (419.1)		46,510,051	79,298,238		
39	Miscellaneous Nonoperating Income (421)		-954,675	27,081,235		
40	Gain on Disposition of Property (421.1)		508,748	2,617,525		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		61,362,141	129,639,692		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		37,115	46,470		
44	Miscellaneous Amortization (425)		1,290,244	1,285,816		
45	Donations (426.1)		3,009,414	2,676,885		
46	Life Insurance (426.2)		-3,079,618	-4,971,828		
47	Penalties (426.3)		238,093	-418,323		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,171,126	2,284,308		
49	Other Deductions (426.5)		8,456,159	29,828,972		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,122,533	30,732,300		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	306,526	367,905		
53	Income Taxes-Federal (409.2)	262-263	-1,538,756	28,723,272		
54	Income Taxes-Other (409.2)	262-263	-209,091	3,903,016		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	59,177,256	85,258,308		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	60,347,318	85,411,869		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		2,064,956	2,065,260		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,676,339	30,775,372		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		53,915,947	68,132,020		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		364,553,118	363,203,396		
63	Amort. of Debt Disc. and Expense (428)		3,910,675	3,727,614		
64	Amortization of Loss on Reaquired Debt (428.1)		1,769,844	2,331,323		
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)		-15,213	-35,853		
68	Other Interest Expense (431)		14,342,093	12,367,152		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		24,643,010	44,618,458		
70	Net Interest Charges (Total of lines 62 thru 69)		359,914,789	336,972,456		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		554,806,039	566,414,836		
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)		554,806,039	566,414,836		

Schedule Page: 114 Line No.: 4 Column: d

Amended in accordance with FERC Order No. AC11-132.

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

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2011 and 2010, depreciation expense associated with transportation equipment was $14,396,524 and $14,065,119, respectively.

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

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

Schedule Page: 114 Line No.: 12 Column: d

The net credit position reflected in account 407.3, Regulatory Debits, primarily represents a true-up to regulatory assets based on currently approved state commission orders for the decommissioning and removal of the Powerdale hydroelectric generating facility.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2011 and 2010, payroll taxes were $40,298,577 and $39,760,547, respectively.

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

Amended in accordance with FERC Order No. AC11-132.

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

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

Schedule Page: 114 Line No.: 36 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 114 Line No.: 67 Column: d

Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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		2,652,408,336	2,103,304,579
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		545,294,570	551,162,090
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	-2,049,846	(2,058,333)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-2,049,846	(2,058,333)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-549,997,605	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-549,997,605	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,645,655,455	2,652,408,336
	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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)		2,649,231,266	2,655,984,147
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		142,404,172	127,151,426
50	Equity in Earnings for Year (Credit) (Account 418.1)		9,511,469	15,252,746
51	(Less) Dividends Received (Debit)			
52	Transfers to/from Unappropriated Retained Earnings (Account 216)			
53	Balance-End of Year (Total lines 49 thru 52)		151,915,641	142,404,172

Schedule Page: 118 Line No.: 1 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 118 Line No.: 16 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 118 Line No.: 24 Column: c

Outstanding shares of preferred stock as of December 31, 2011 and dividends on preferred stock during the year ended December 31, 2011 were as follows:

	Shares	Dividend
4.52% Serial Preferred	2,065	$ 9,334
4.56% Serial Preferred	81,326	370,846
4.72% Serial Preferred	65,854	310,830
5.00% Serial Preferred	41,908	209,540
5.40% Serial Preferred	65,959	356,179
6.00% Serial Preferred	5,930	35,580
7.00% Serial Preferred	18,046	126,322
5.00% Preferred	126,243	631,215
	407,331	$2,049,846

Schedule Page: 118 Line No.: 24 Column: d

Outstanding shares of preferred stock as of December 31, 2010 and dividends on preferred stock during the year ended December 31, 2010 were as follows:

	Shares	Dividend
4.52% Serial Preferred	2,065	$ 9,334
4.56% Serial Preferred	81,326	374,570
4.72% Serial Preferred	65,854	315,593
5.00% Serial Preferred	41,908	209,540
5.40% Serial Preferred	65,959	356,179
6.00% Serial Preferred	5,930	35,580
7.00% Serial Preferred	18,046	126,322
5.00% Preferred	126,243	631,215
	407,331	$2,058,333

Schedule Page: 118 Line No.: 31 Column: c

For information regarding common stock dividends declared, refer to Important Changes During the Quarter/Year, Item 6 and Note 15 of Notes to Financial Statements in this Form No. 1.

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

Amended in accordance with FERC Order No. AC11-132.

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

The balance in Account 215.1, Appropriated retained earnings - amortization reserve, federal is due to requirements of certain hydroelectric relicensing projects.

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

See footnote for column (c) line 47.

Schedule Page: 118 Line No.: 49 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 118 Line No.: 50 Column: d

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	554,806,039	566,414,836
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	560,591,577	517,014,250
5	Amortization:	50,140,207	44,162,057
6			
7	Unrealized Gains on Derivative Contracts	1,116,177	-1,892,323
8	Deferred Income Taxes (Net)	357,507,026	703,524,635
9	Investment Tax Credit Adjustment (Net)	-3,939,160	-3,939,464
10	Net (Increase) Decrease in Receivables	-60,824,263	-9,036,806
11	Net (Increase) Decrease in Inventory	-58,556,736	-25,822,080
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-34,182,597	-142,254,307
14	Net (Increase) Decrease in Other Regulatory Assets	-62,618,384	8,890,615
15	Net Increase (Decrease) in Other Regulatory Liabilities	39,724,553	-4,813,321
16	(Less) Allowance for Other Funds Used During Construction	46,510,051	79,298,238
17	(Less) Undistributed Earnings from Subsidiary Companies	9,511,469	15,252,746
18	Amounts Due To/From Affiliates (Net)	313,928,254	-81,939,950
19	Derivative Collateral (Net)	3,796,008	-102,246,009
20	Other Operating Activities:	20,520,369	22,143,762
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,625,987,550	1,395,654,911
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,532,049,103	-1,686,214,575
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	-46,510,051	-79,298,238
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,485,539,052	-1,606,916,337
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,788,112	7,282,766
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-32,230,537	
40	Contributions and Advances from Assoc. and Subsidiary Companies		2,763,144
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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:	-896,877	2,357,390
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,516,878,354	-1,594,513,037
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	396,249,388	
62	Preferred Stock		
63	Common Stock		
64	Equity Contribution		100,000,000
65			
66	Net Increase in Short-Term Debt (c)	652,437,287	35,999,320
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,048,686,675	135,999,320
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-586,686,000	-14,602,000
74	Preferred Stock		-560,528
75	Common Stock		
76	Other (provide details in footnote):		
77	Repayment of Capital Lease Obligations	-1,364,856	-1,724,876
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-2,049,846	-2,066,818
81	Dividends on Common Stock	-549,997,605	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-91,411,632	117,045,098
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	17,697,564	-81,813,028
87			
88	Cash and Cash Equivalents at Beginning of Period	4,395,676	86,208,704
89			
90	Cash and Cash Equivalents at End of period	22,093,240	4,395,676

Schedule Page: 120 Line No.: 4 Column: b

Includes depreciation expense associated with transportation equipment and capital lease assets of $15,761,379 and $15,789,994 during the years ended December 31, 2011 and 2010, respectively.

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

	Years Ended December 31, 2011	Years Ended December 31, 2010
Amortization of software development & other intangibles	$ 43,494,603	$ 36,124,109
Amortization of electric plant acquisition adjustments	5,523,970	5,518,393
Amortization of regulatory assets	1,121,634	2,519,555
	$ 50,140,207	$ 44,162,057

Schedule Page: 120 Line No.: 10 Column: c

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 13 Column: c

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 17 Column: c

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

	Years Ended December 31, 2011	Years Ended December 31, 2010
Coal & steam depreciation and depletion included in cost of fuel	$ 11,712,355	$ 12,685,957
Gain on sale of property	(497,935)	(2,992,914)
Write-off of assets under construction	5,085,213	8,670,990
Other	4,220,736	3,779,729
	$ 20,520,369	$ 22,143,762

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

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 37 Column: b

Represents proceeds from disposal of fixed assets.

Schedule Page: 120 Line No.: 37 Column: c

Represents proceeds from disposal of fixed assets.

Schedule Page: 120 Line No.: 39 Column: c

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 40 Column: c

Amended in accordance with FERC Order No. AC11-132.

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

	Years Ended December 31, 2011	Years Ended December 31, 2010
Other investments/special funds	$ 919,658	$ (371,886)
Temporary facilities	23,771	(785)
Restricted cash	(1,840,306)	2,730,061
	$ (896,877)	$ 2,357,390

Footnote amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 88 Column: b

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 120 Line No.: 88 Column: c

Amended in accordance with FERC Order No. AC11-132.

NOTES TO FINANCIAL STATEMENTS

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

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

PACIFICORP
NOTES TO FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp 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, financial institutions and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining 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

Restatement

On April 17, 2012, the Federal Energy Regulatory Commission ("FERC") issued an order in response to PacifiCorp’s requests in FERC Docket No. AC11-132, requiring certain restatements and revisions in PacifiCorp’s accounting practices related to its accounting for its wholly owned coal mining and management subsidiaries for FERC reporting purposes. Historically, these entities were consolidated and intercompany profits were eliminated. Under the requirements of the order, PacifiCorp is required to account for these subsidiaries under the equity method and not eliminate profit on intercompany transactions.

In accordance with the order, PacifiCorp has resubmitted its 2011 and 2010 previously filed Forms No. 1 in order to restate the 2010 and 2009 information on the basis required in the order. The 2011 Form No. 1 reflects the restatement of the 2010 comparative period. The 2010 Form No. 1 presents the restatements of the 2010 and 2009 periods. These restatements resulted in adjustments to accounts: 123, Investment in Associated Companies; 123.1, Investment in Subsidiary Companies; 131, Cash; 143, Other Accounts Receivable; 145, Notes Receivable from Associated Companies; 146, Accounts Receivable from Associated Companies; 165, Prepayments; 186, Miscellaneous Deferred Debits; 216, Unappropriated Retained Earnings; 216.1, Unappropriated Undistributed Subsidiary Earnings; 228.3, Accumulated Provision for Pensions and Benefits; 228.4, Accumulated Miscellaneous Operating Provisions; 232, Accounts Payable; 234, Accounts Payable to Associated Companies; 236, Taxes Accrued; 241, Tax Collections Payable; 242, Miscellaneous Current and Accrued Liabilities; 253, Other Deferred Credits; 401, Operation Expense; 409.1, Income Taxes, Utility Operating Income; 418.1, Equity in Earnings of Subsidiary Companies; and 430, Interest on Debt to Associated Companies. As a result of these adjustments, the following lines in the Statement of Cash Flows for the 2010 and 2009 periods were restated: Net (Increase) Decrease in Receivables; Net Increase (Decrease) in Payables and Accrued Expenses; Undistributed Earnings from Subsidiary Companies; Amounts Due To/From Affiliates (Net); Other Operating Activities; Investments in and Advances to Associated and Subsidiary Companies; Contributions and Advances from Associated and Subsidiary Companies; Other Investing Activities; Cash and Cash Equivalents at Beginning of Period; and Cash and Cash Equivalents at End of Period. The following lines in the Statement of Cash Flows for the 2011 period were restated: Amounts Due To/From Affiliates (Net); Gross Additions to Utility Plant (less nuclear fuel); Other Investing Activities; and Cash and Cash Equivalents at Beginning of Period.

These notes do not include the quantitative impacts of the restatement described above as required by accounting principles generally accepted in the United States of America ("GAAP").

Basis of Presentation

These financial statements are prepared in accordance with the requirements of 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 GAAP. These notes include certain applicable 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

In accordance with FERC Order No. AC11-132, PacifiCorp accounts for its investment in subsidiaries using the equity method for FERC reporting purposes rather than consolidating the assets, liabilities, revenues and expenses of subsidiaries as required by GAAP. GAAP requires that entities in which a company holds a controlling financial interest be consolidated. The accounting for the investment in subsidiaries using the equity method rather than the consolidation method in accordance with GAAP has no effect on net income or the combined retained earnings of PacifiCorp and undistributed earnings of subsidiaries.

Costs of Removal

Estimated removal costs that are recovered through approved depreciation rates, but that do not meet the requirements of a legal asset retirement obligation ("ARO"), are reflected in the cost of removal 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."

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.

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 the 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, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; AROs; income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. 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 rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future 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 evaluation, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

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. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in United States Treasury Bills, money market funds and 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):

	2011	2010
Cash (131)	$ 15	$ 4
Working funds (135)	—	—
Temporary cash investments (136)	7	—
Total cash and cash equivalents	$ 22	$ 4

Investments

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in AOCI, net of tax. As of December 31, 2011 and 2010, PacifiCorp had no unrealized gains and losses on available-for-sale securities.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of estimated allowances for doubtful accounts. The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay 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 is summarized as follows for the years ended December 31 (in millions):

	2011	2010
Beginning balance	$ 8	$ 7
Charged to operating costs and expenses, net	13	12
Write-offs, net	(12)	(11)
Ending balance	$ 9	$ 8

Derivatives

PacifiCorp employs a number of different derivative contracts, including forwards, 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 estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting 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 or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenues or operation expenses on the Statement of Income.

For PacifiCorp's derivatives not designated as hedging contracts, the settled amount is generally included in 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 rates are recorded as net regulatory assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

Inventories

Inventories consist 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

Additions to utility plant are recorded at cost. PacifiCorp capitalizes all construction related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and 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 recovered through approved depreciation rates. Estimated removal costs are recorded as either accumulated provision for depreciation or as an ARO liability on the Comparative Balance Sheet, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when PacifiCorp retires or sells a component of utility plant, it charges the original cost and any net proceeds from the disposition 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. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives 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. PacifiCorp's AROs are primarily associated with its generating facilities. 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 original estimate of undiscounted cash flows (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 billed, as well as unbilled, amounts. As of December 31, 2011 and 2010, unbilled revenue was $237 million and $206 million, respectively, and is included in accrued utility revenues, net on the Comparative Balance Sheet. Rates charged are established by regulators or contractual arrangements.

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, energy provided to customers since the date of the last meter reading is 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, total volumes supplied to the system, line losses, economic impacts 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 income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income 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 ("OCI") are charged or credited directly to OCI. 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 are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling $422 million and $426 million as of December 31, 2011 and 2010, respectively, and will be included in 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. PacifiCorp's tax returns are 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. 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 upon 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 50% likelihood of being realized upon ultimate settlement. 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's unrecognized tax benefits are primarily included in Taxes accrued on the Comparative Balance Sheet. 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 December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, which amends FASB Accounting Standards Codification ("ASC") Topic 210, "Balance Sheet." The amendments in this guidance require an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance is effective for fiscal years beginning on or after January 1, 2013, 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 September 2011, the FASB issued ASU No. 2011-09, which amends FASB ASC Subtopic 715-80, "Compensation-Retirement Benefits-Multiemployer Plans." The amendments in this guidance require additional disclosures regarding an entity's participation in multiemployer pension plans and other postretirement benefit plans, as well as certain qualitative and quantitative disclosures regarding individually significant multiemployer pension plans. PacifiCorp adopted this guidance as of December 31, 2011. Refer to the additional disclosures required by ASU No. 2011-09 at Note 11.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011-04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. PacifiCorp is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Financial Statements.

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." 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. PacifiCorp adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which PacifiCorp adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on PacifiCorp's disclosures included within Notes to Financial Statements.

(3) Net Utility Plant

The average depreciation and amortization rate applied to depreciable utility plant was 2.8% for the years ended December 31, 2011 and 2010 and 2.9% for the year ended December 31, 2009.

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 $159 million as of December 31, 2011 and 2010 and accumulated provision for depreciation, amortization and depletion of $107 million and $102 million as of December 31, 2011 and 2010, respectively.

(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, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. 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, 2011 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,074	$ 506	$ 21
Hunter No. 1	94	342	147	43
Hunter No. 2	60	291	80	12
Wyodak	80	449	150	1
Colstrip Nos. 3 and 4	10	222	119	2
Hermiston	50	171	53	1
Craig Nos. 1 and 2	19	176	91	—
Hayden No. 1	25	51	25	—
Hayden No. 2	13	32	16	—
Foote Creek	79	37	18	—
Transmission and distribution facilities	Various	315	54	1
Total		$ 3,160	$ 1,259	$ 81

(5) Regulatory Matters

PacifiCorp had regulatory assets not earning a return on investment of $1.662 billion and $1.575 billion as of December 31, 2011 and 2010, respectively.

(6) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, special funds, other investments, payables, accrued liabilities and short-term borrowings approximates 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 (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	**Level 2**	**Level 3**	**Other(1)**	**Total**
As of December 31, 2011					
Assets:					
Commodity derivatives	$ —	$ 114	$ 1	$ (100)	$ 15
Investments in available-for-sale securities - Money market mutual funds(2)	9	—	—	—	9
	$ 9	$ 114	$ 1	$ (100)	$ 24
Liabilities - Commodity derivatives	$ —	$ (379)	$ —	$ 223	$ (156)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ —	$ 263	$ 5	$ (145)	$ 123
Investments in available-for-sale securities - Money market mutual funds(2)	2	—	—	—	2
	$ 2	$ 263	$ 5	$ (145)	$ 125
Liabilities - Commodity derivatives	$ —	$ (405)	$ (350)	$ 272	$ (483)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $123 million and $127 million as of December 31, 2011 and 2010, respectively.

(2) 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.

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 or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. PacifiCorp bases its forward price curves upon 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 unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. 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, spread option and best-of option, with the appropriate forward price curve and other inputs.

PacifiCorp's investments in money market mutual funds are accounted for as available-for-sale securities and are stated at fair value. PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value.

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):

	2011	2010
Beginning balance	$ (345)	$ (380)
Changes in fair value recognized in net regulatory assets	132	(38)
Contracts designated as normal purchases or normal sales	168	—
Settlements	46	73
Ending balance	$ 1	$ (345)

In December 2011, PacifiCorp elected to designate certain derivative contracts as normal purchases or normal sales, an exception afforded by GAAP. As a result of making the designation, the fair value of the contracts was frozen as of December 31, 2011 and $168 million of net derivative liabilities was reclassified from derivative contracts to other assets and liabilities. The frozen liability and associated regulatory asset will be amortized over the remaining terms of the agreements.

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 upon 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 value 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 value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

	2011		2010	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 6,157	$ 7,804	$ 6,344	$ 7,086

(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, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territories. PacifiCorp's load and generating facilities 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. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt 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 price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, 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 primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate 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 reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or 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 (in millions):

	Derivative Assets		Derivative Liabilities		
	Current	**Noncurrent**	**Current**	**Noncurrent**	**Total**
As of December 31, 2011					
Not designated as hedging contracts(1)(2):					
Commodity assets	$ 30	$ 7	$ 66	$ 12	$ 115
Commodity liabilities	(17)	(3)	(242)	(117)	(379)
Total	13	4	(176)	(105)	(264)
Total derivatives	13	4	(176)	(105)	(264)
Cash collateral (payable) receivable	(2)	—	86	39	123
Total derivatives - net basis	$ 11	$ 4	$ (90)	$ (66)	$ (141)
As of December 31, 2010					
Not designated as hedging contracts(1)(2):					
Commodity assets	$ 185	$ 13	$ 34	$ 36	$ 268
Commodity liabilities	(62)	(4)	(213)	(476)	(755)
Total	123	9	(179)	(440)	(487)
Total derivatives	123	9	(179)	(440)	(487)
Cash collateral (payable) receivable	(9)	—	95	41	127
Total derivatives - net basis	$ 114	$ 9	$ (84)	$ (399)	$ (360)

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

(2) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2011 and 2010, a net regulatory asset of $264 million and $487 million, respectively, was recorded related to the net derivative liability of $264 million and $487 million, respectively.

For PacifiCorp's commodity derivatives, the settled amount is generally included in 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 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 years ended December 31 (in millions):

	2011	2010
Beginning balance	$ 487	$ 367
Changes in fair value recognized in net regulatory assets	(2)	90
Net losses reclassified to unamortized contract value regulatory asset	(168)	—
Net gains reclassified to operating revenue	18	64
Net losses reclassified to energy costs	(71)	(34)
Ending balance	$ 264	$ 487

For PacifiCorp's derivatives for which changes in fair value are not recorded as a net regulatory asset, unrealized gains and losses are recognized on the Statement of Income as miscellaneous nonoperating income for unrealized gains and as other deductions for unrealized losses. During the years ended December 31, 2011 and 2010, these amounts were insignificant.

Derivative Contract Volumes

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

	Unit of Measure	2011	2010
Commodity contracts:			
Electricity sales	Megawatt hours	(2)	(13)
Natural gas purchases	Decatherms	96	159
Fuel oil purchases	Gallons	17	16

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with its 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 obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed 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 wholesale 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, 2011, 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 $378 million and $448 million as of December 31, 2011 and 2010, respectively, for which PacifiCorp had posted collateral of $125 million and $136 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2011 and 2010, PacifiCorp would have been required to post $155 million and $129 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(8) Short-term Debt and Other Financing Agreements

PacifiCorp has a $635 million unsecured credit facility expiring in October 2012 and an unsecured credit facility with $720 million available until July 2012, and $630 million until July 2013. 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, 2011, PacifiCorp had $688 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.5% and no borrowings outstanding under its credit facilities. As discussed in Note 9, in January 2012, PacifiCorp issued $650 million of long-term debt, the proceeds of which were in part used to repay a significant portion of the commercial paper borrowings outstanding as of December 31, 2011. As of December 31, 2010, PacifiCorp had $36 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.3% and no borrowings outstanding under its credit facilities.

As of December 31, 2011 and 2010, PacifiCorp had $601 million of letters of credit issued under committed arrangements, of which $304 million were issued under the revolving credit agreements. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations, were fully available as of December 31, 2011 and 2010, and expire periodically from May 2012 through November 2012.

Each revolving credit agreement and letter of credit arrangement requires that PacifiCorp's ratio of debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0. As of December 31, 2011, PacifiCorp was in compliance with the covenants of its revolving credit agreements and letter of credit arrangements.

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

2011:		
Available revolving credit facilities	$	1,355
Less:		
Short-term debt		(688)
Letters of credit supporting tax-exempt bond obligations		(304)
Net revolving credit facilities available	$	363
2010:		
Available revolving credit facilities	$	1,395
Less:		
Short-term debt		(36)
Letters of credit supporting tax-exempt bond obligations		(304)
Net revolving credit facilities available	$	1,055

As of December 31, 2011, PacifiCorp had approximately $13 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These letters of credit were all undrawn as of December 31, 2011 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 may include provisions that allow PacifiCorp to redeem the long-term debt in whole or in part at any time. These provisions generally include make-whole premiums.

In March 2012, PacifiCorp issued $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. The net proceeds were used for the redemption of certain tax-exempt bonds, repayment of short-term debt and general corporate purposes.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes.

In May 2011, PacifiCorp issued $400 million of its 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission to issue an additional $850 million of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission expected to provide for future first mortgage bond issuances through November 2013.

In September 2010, PacifiCorp completed a re-offering of variable-rate tax-exempt bond obligations totaling $38 million. Letters of credit totaling $39 million were issued under one of PacifiCorp's unsecured revolving credit facilities to provide credit enhancement and liquidity support for these previously unenhanced obligations.

In June 2010, PacifiCorp completed a re-offering of a $45 million series of tax-exempt bond obligations. The interest rate for this obligation was previously fixed for a term which, upon scheduled expiration, was converted to a variable rate with credit enhancement and liquidity support provided by a $46 million letter of credit issued under one of PacifiCorp's unsecured revolving credit facilities.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $22 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2011.

PacifiCorp's letters of credit agreements generally contain similar covenants and default provisions as those contained in PacifiCorp's revolving credit facilities, 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 do not occur. As of December 31, 2011, 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 capital lease assets of $56 million and $57 million as of December 31, 2011 and 2010, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2011, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2012 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2012	$ 17	$ 7	$ 24
2013	261	12	273
2014	253	8	261
2015	122	7	129
2016	57	7	64
Thereafter	5,461	80	5,541
Total	6,171	121	6,292
Unamortized discount	(14)	—	(14)
Amounts representing interest	—	(65)	(65)
Total	$ 6,157	$ 56	$ 6,213

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. 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 accumulated provision for depreciation established via approved depreciation rates and in accordance with accepted regulatory practices. These accruals totaled $782 million as of December 31, 2011 and 2010.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2011	2010
Beginning balance	$ 105	$ 103
Change in estimated costs(1)	2	2
Additions	29	1
Retirements	(19)	(6)
Accretion	6	5
Ending balance	$ 123	$ 105

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

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp 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 and other postretirement benefit plans that cover the majority of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). PacifiCorp and one of its subsidiaries contribute to multiemployer pension plans for benefits offered to certain bargaining units.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to employees hired after January 1, 2008 for all non-union employees. The SERP was closed to new participants as of March 21, 2006. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401(k) Plan effective January 1, 2009, earn benefits based on a cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

Plan Amendments and Curtailments

Effective January 1, 2012, PacifiCorp changed the medical benefits for the majority of Medicare-eligible participants in its other postretirement benefit plan. Medicare-eligible participants now enroll in individual medical plans, rather than company-sponsored plans, under which PacifiCorp contributes fixed amounts to the participant's health reimbursement account. As a result of this change, PacifiCorp's benefit obligation for its other postretirement benefit plan and its related regulatory assets decreased $54 million as of December 31, 2011.

Effective March 31, 2010, the Utility Workers Union of America Local Union No. 127 ("Local 127") 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 127 participants' Retirement Plan benefits were frozen on March 31, 2010. This change resulted in a $2 million curtailment gain that was recorded as a regulatory deferral and is being amortized over periods similar to those required for other recent curtailments. Also as a result of this change, PacifiCorp's pension benefit obligation and regulatory assets each decreased by $14 million as of December 31, 2010.

Healthcare Reform Legislation

In March 2010, the President signed into law healthcare reform legislation that included provisions to reduce the tax deductibility of other postretirement costs by the amount of retiree drug subsidies received from the federal government beginning after December 31, 2012. As a result of the legislation, PacifiCorp increased deferred income tax liabilities and regulatory assets by $39 million during the year ended December 31, 2010. PacifiCorp has received authorization from various state regulatory commissions for deferral of substantially all of the $16 million portion of the adjustment that related to income tax benefits associated with amounts previously recognized as net periodic benefit costs. The remaining $23 million of the adjustment relates to income tax benefits that will no longer be realized in the future when the net periodic benefit cost is recognized and for which recovery of the resulting higher future income tax expense will be addressed through on-going ratemaking proceedings.

The law also contains a provision that requires a 40% excise tax for group health benefits that are provided to employees above certain premium thresholds beginning in 2018. The tax would apply to the amount of premiums in excess of the thresholds. Virtually all major areas of the healthcare reform legislation, including the 40% excise tax, are subject to interpretation and implementation rules that may take several years to complete. As of December 31, 2010, PacifiCorp's other postretirement benefit obligation increased by $12 million as a result of the projected impact of the excise tax on benefits provided to a certain bargaining unit.

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	
	2011	**2010**	**2011**	**2010**
Service cost	$ 10	$ 12	$ 7	$ 6
Interest cost	63	66	31	31
Expected return on plan assets	(75)	(74)	(30)	(30)
Net amortization	29	23	17	14
Net amortization of regulatory deferrals	(9)	(10)	1	1
Net periodic benefit cost	$ 18	$ 17	$ 26	$ 22

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	
	2011	**2010**	**2011**	**2010**
Plan assets at fair value, beginning of year	$ 960	$ 825	$ 389	$ 350
Employer contributions	71	117	28	24
Participant contributions	—	—	9	9
Actual return on plan assets	(13)	102	(4)	44
Benefits paid	(87)	(84)	(38)	(38)
Plan assets at fair value, end of year	$ 931	$ 960	$ 384	$ 389

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

	Pension		Other Postretirement	
	2011	2010	2011	2010
Benefit obligation, beginning of year	$ 1,236	$ 1,199	$ 581	$ 545
Service cost	10	12	7	6
Interest cost	63	66	31	31
Participant contributions	—	—	9	9
Plan amendments	(4)	—	(54)	—
Curtailment	—	(14)	—	—
Actuarial loss	73	57	36	25
Benefits paid, net of Medicare subsidy	(87)	(84)	(35)	(35)
Benefit obligation, end of year	$ 1,291	$ 1,236	$ 575	$ 581
Accumulated benefit obligation, end of year	$ 1,289	$ 1,230		

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

	Pension		Other Postretirement	
	2011	2010	2011	2010
Plan assets at fair value, end of year	$ 931	$ 960	$ 384	$ 389
Less - Benefit obligation, end of year	1,291	1,236	575	581
Funded status	$ (360)	$ (276)	$ (191)	$ (192)
Amounts recognized on the Comparative Balance Sheet:				
Other current liabilities	$ (4)	$ (4)	$ —	$ —
Other long-term liabilities	(356)	(272)	(191)	(192)
Amounts recognized	$ (360)	$ (276)	$ (191)	$ (192)

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 $41 million and $40 million as of December 31, 2011 and 2010, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent other assets on the Comparative Balance Sheet. The portion of the pension plans' projected benefit obligation related to the SERP was $58 million and $56 million as of December 31, 2011 and 2010, respectively.

Unrecognized Amounts

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

	Pension		**Other Postretirement**	
	2011	**2010**	**2011**	**2010**
Net loss	$ 630	$ 507	$ 206	$ 142
Prior service credit	(45)	(50)	(46)	—
Net transition obligation	—	—	—	19
Regulatory deferrals	(7)	(16)	3	4
Total	$ 578	$ 441	$ 163	$ 165

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2011 and 2010 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2009	$ 430	$ 9	$ 439
Net loss arising during the year	27	2	29
Curtailment	(14)	—	(14)
Net amortization	(13)	—	(13)
Total	—	2	2
Balance, December 31, 2010	430	11	441
Net loss arising during the year	157	4	161
Prior service credit arising during the year	(4)	—	(4)
Net amortization	(19)	(1)	(20)
Total	134	3	137
Balance, December 31, 2011	$ 564	$ 14	$ 578

	Regulatory Asset	Deferred Income Taxes	Total
Other Postretirement			
Balance, December 31, 2009	$ 146	$ 23	$ 169
Net loss arising during the year	11	—	11
Income tax benefits no longer realizable (1)	23	(23)	—
Net amortization	(15)	—	(15)
Total	19	(23)	(4)
Balance, December 31, 2010	165	—	165
Net loss arising during the year	70	—	70
Prior service credit arising during the year	(46)	—	(46)
Reduction in net transition obligation	(8)	—	(8)
Net amortization	(18)	—	(18)
Total	(2)	—	(2)
Balance, December 31, 2011	$ 163	$ —	$ 163

(1) Represents adjustments to regulatory assets associated with income tax benefits that will no longer be realized when the net periodic benefit cost is recognized as a result of the healthcare reform legislation.

The net loss, prior service credit and regulatory deferrals that will be amortized in 2012 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 44	$ (8)	$ (2)	$ 34
Other postretirement	10	(7)	1	4
Total	$ 54	$ (15)	$ (1)	$ 38

Plan Assumptions

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

	Pension		Other Postretirement	
	2011	2010	2011	2010
Benefit obligations as of December 31:				
Discount rate	4.90 %	5.35 %	4.95 %	5.45 %
Rate of compensation increase	3.50	3.50	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	5.35 %	5.80 %	5.45 %	5.85 %
Expected return on plan assets	7.50	7.75	7.50	7.75
Rate of compensation increase	3.50	3.00	N/A	N/A

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

	2011	2010
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.50%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2016	2016

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
Increase (decrease) in:		
Total service and interest cost	$ 3	$ (2)
Other postretirement benefit obligation	45	(36)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $49 million and $9 million, respectively, during 2012. 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 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to contribute an amount equal to the sum of the net periodic benefit cost and the amount of Medicare subsidies expected to be earned during the period.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2012 through 2016 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	Gross	Medicare Subsidy	Net of Subsidy
2012	$ 99	$ 35	$ —	$ 35
2013	103	36	(1)	35
2014	104	36	(1)	35
2015	105	37	(1)	36
2016	108	38	(1)	37
2017 - 2021	492	203	(9)	194

Plan Assets

Investment Policy and Asset Allocations

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt 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. The investment portfolio is managed 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.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2011:

	Pension(1)	**Other Postretirement**(1)
	%	%
Debt securities(2)	33 - 37	33 - 37
Equity securities(2)	53 - 57	61 - 65
Limited partnership interests	8 - 12	1 - 3
Other	0 - 1	0 - 1

(1) PacifiCorp's Retirement 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' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1(1)	**Level 2(1)**	**Level 3(1)**	**Total**
As of December 31, 2011				
Cash equivalents	$ —	$ 9	$ —	$ 9
Debt securities:				
United States government obligations	21	—	—	21
International government obligations	—	73	—	73
Corporate obligations	—	63	—	63
Municipal obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	45	—	45
Equity securities:				
United States companies	366	—	—	366
International companies	7	—	—	7
Investment funds(2)	104	165	—	269
Limited partnership interests(3)	—	—	71	71
Total	$ 498	$ 362	$ 71	$ 931
As of December 31, 2010				
Cash equivalents	$ —	$ 8	$ —	$ 8
Debt securities:				
United States government obligations	20	—	—	20
International government obligations	—	81	—	81
Corporate obligations	—	52	—	52
Municipal obligations	—	4	—	4
Agency, asset and mortgage-backed obligations	—	49	—	49
Equity securities:				
United States companies	366	—	—	366
International equity companies	7	—	—	7
Investment funds(2)	109	180	—	289
Limited partnership interests(3)	—	—	84	84
Total	$ 502	$ 374	$ 84	$ 960

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

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 59% and 41%, respectively, for 2011 and 60% and 40%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 49% and 51%, respectively, for 2011 and 47% and 53%, respectively, for 2010.

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

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
December 31, 2011				
Cash and cash equivalents	$ 3	$ —	$ —	$ 3
Debt securities:				
United States government obligations	2	—	—	2
International government obligations	—	5	—	5
Corporate obligations	—	5	—	5
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	3	—	3
Equity securities:				
United States companies	131	—	—	131
International companies	2	—	—	2
Investment funds[(2)]	132	94	—	226
Limited partnership interests[(3)]	—	—	6	6
Total	$ 270	$ 108	$ 6	$ 384
December 31, 2010				
Cash and cash equivalents	$ 2	$ 1	$ —	$ 3
Debt securities:				
United States government obligations	2	—	—	2
International government obligations	—	7	—	7
Corporate obligations	—	4	—	4
Agency, asset and mortgage-backed obligations	—	4	—	4
Equity securities:				
United States companies	134	—	—	134
International companies	3	—	—	3
Investment funds[(2)]	118	107	—	225
Limited partnership interests[(3)]	—	—	7	7
Total	$ 259	$ 123	$ 7	$ 389

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

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 48% and 52%, respectively, for 2011, and 47% and 53%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 69% and 31%, respectively, for both 2011 and 2010.

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

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 partnership interests 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 years ended December 31 (in millions):

	Private Equity Funds	
	Pension	Other Postretirement
Balance, December 31, 2009	$ 80	$ 8
Actual return on plan assets still held at December 31, 2010	10	—
Purchases, sales, distributions and settlements	(6)	(1)
Balance, December 31, 2010	84	7
Actual return on plan assets still held at December 31, 2011	7	1
Purchases, sales, distributions and settlements	(20)	(2)
Balance, December 31, 2011	$ 71	$ 6

Multiemployer Plans

PacifiCorp and one of its subsidiaries contribute to the following two multiemployer pension plans under the terms of collective bargaining agreements: (a) the United Mine Workers of America 1974 Pension Plan ("UMWA Pension Plan") (plan number 002); and (b) the PacifiCorp/IBEW Local Union 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001). The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert back to employers. If participating employers withdraw from the plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that may have recently withdrawn. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan.

The following table presents PacifiCorp's and its subsidiary's participation in individually significant multiemployer pension plans for the years ended December 31 (dollars in millions):

		PPA zone status or plan funded status percentage for plan years beginning July 1,(1)				PacifiCorp's contributions(2)		
Plan name	**Employer Identification Number**	**2011**	**2010**	**Funding improvement plan**	**Surcharge imposed under PPA**	**2011**	**2010**	**Year contributions to plan exceeded more than 5% of total contributions(5)**
UMWA Pension Plan	52-1050282	Yellow	Green (3)	Pending	None	$ 3	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%(6)	At least 80%	None	None	$ 12	$ 9	2010, 2009

(1) Among other factors, multiemployer plans in the red zone are generally less than 65 percent funded, multiemployer plans in the yellow zone are at least 65 percent but less than 80 percent funded and multiemployer plans in the green zone are at least 80 percent funded.

(2) PacifiCorp's minimum contributions to the multiemployer pension plans are based on the number of mining hours worked for the UMWA Pension Plan or the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreement, subject to ERISA minimum funding requirements.

(3) The UMWA Pension Plan elected to extend recognition of investment losses incurred during the plan year ended June 30, 2009 pursuant to the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010. Had the election not been made, the PPA zone status would have been yellow for the plan year beginning July 1, 2010.

(4) The UMWA Pension Plan elected to retain the green PPA zone status from the plan year beginning July 1, 2008 for the plan year beginning July 1, 2009 pursuant to Section 204 of the Worker, Retiree and Employer Recovery Act of 2008. Had the election not been made, the PPA zone status would have been yellow for the plan year beginning July 1, 2009.

(5) For the UMWA Pension Plan, information is for plan year beginning July 1, 2009. Information for the plan years beginning July 1, 2010 and 2011 is not available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2010 and 2009. Information for the plan year beginning July 1, 2011 is not yet available.

(6) The preliminary plan funded status for the plan year beginning July 1, 2011 was at least 80%. PacifiCorp expects the final plan funded status, which is determined after the plan year end, will be at least 80%.

The current collective bargaining agreements governing the UMWA Pension Plan and the Local 57 Trust Fund expire in January 2013.

Defined Contribution Plan

PacifiCorp sponsors a defined contribution plan (401(k) plan) covering 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. PacifiCorp's contributions to the 401(k) plan were $38 million and $39 million for the years ended December 31, 2011 and 2010, respectively.

(12) Income Taxes

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

	2011	2010
Current:		
Federal	$ (140)	$ (495)
State	(8)	(1)
Total	(148)	(496)
Deferred:		
Federal	320	675
State	37	29
Total	357	704
Investment tax credits	(4)	(4)
Total income tax expense	$ 205	$ 204

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:

	2011	2010
Federal statutory income tax rate	35 %	35 %
State income taxes, net of federal benefit	3	3
Tax credits(1)	(10)	(8)
Effects of ratemaking	—	(2)
Other	(1)	(1)
Effective income tax rate	27 %	27 %

(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):

	2011	2010
Deferred tax assets:		
Employee benefits	$ 210	$ 187
Derivative contracts	100	185
Unamortized contract values	72	—
Regulatory liabilities	43	26
Other	215	191
	640	589
Deferred tax liabilities:		
Property, plant and equipment	(3,670)	(3,342)
Regulatory assets	(715)	(650)
Other	(32)	(30)
	(4,417)	(4,022)
Net deferred tax liability	$ (3,777)	$ (3,433)

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.

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.

As of December 31, 2011 and 2010, net unrecognized tax benefits totaled $64 million and $70 million, respectively, which included $8 million and $9 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.

(13) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material impact on its financial results.

USA Power

On May 21, 2012, the jury reached a verdict in the case of USA Power, LLC et al. vs. PacifiCorp et al. filed in the Third District Court of Salt Lake County, Utah ("Third District Court") in favor of USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff") regarding the Plaintiff's claims that PacifiCorp breached a confidentiality agreement and willfully misappropriated the Plaintiff's trade secrets in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. The jury awarded the Plaintiff breach of contract damages of $18 million and unjust enrichment damages of $113 million against PacifiCorp. On May 24, 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of the amounts awarded in the case. The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. The judge set a schedule for PacifiCorp to file its post-trial motions for a new trial and a judgment notwithstanding the verdict in the fall of 2012. If the judge grants either of PacifiCorp's motions, then the Plaintiff's motions for exemplary damages and attorneys' fees will be moot. If the judge does not grant either of PacifiCorp's motions, then the judge will set a schedule for PacifiCorp to respond to the Plaintiff's motions for exemplary damages and attorneys' fees. In the event the judge does not grant either of PacifiCorp's motions, PacifiCorp expects a decision on the Plaintiff's motions for exemplary damages and attorneys' fees in 2013, and PacifiCorp expects to appeal the final judgment. The suit was originally filed in 2005, prior to MEHC's ownership of PacifiCorp. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In February 2008, the Plaintiff filed a petition requesting consideration by the Utah Supreme Court on two of its five claims. In May 2010, the Utah Supreme Court reversed and remanded the case back to the Third District Court for further consideration. PacifiCorp strongly disagrees with the verdict and is aggressively pursuing all options for appeal. PacifiCorp is currently assessing the range of possible loss.

FERC Investigation

During 2007, the Western Electricity Coordinating Council ("WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation ("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. In July 2009, PacifiCorp reached a settlement with the WECC for the aspects of the audit that were not assumed by the FERC. The settlement with the WECC did not have a material impact on PacifiCorp's financial results. In December 2011, the FERC approved a settlement among PacifiCorp, the FERC and the NERC resolving the WECC audit items that were under the FERC's control, as well as the inquiry into the February 2008 outage. The results of the settlement did not have a material impact on PacifiCorp's financial results.

Northwest Refund Case

In October 2011, the FERC issued an order on remand by the United States Court of Appeals for the Ninth Circuit, in which it determined that additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest wholesale spot market during the period from December 2000 through June 2001. PacifiCorp was a participant in the Pacific Northwest wholesale spot market during this period. The FERC ordered an evidentiary, trial-type hearing before an administrative law judge to permit parties to present evidence of alleged unlawful market activity. However, the FERC held the hearing in abeyance pending settlement discussions with all parties, which are ongoing. PacifiCorp does not believe that the outcome of this proceeding will have a material impact on its financial results.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, 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 all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 44 generating facilities with an aggregate facility net owned capacity of 1,145 megawatts ("MW"). The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which 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 2010, 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 Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. 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. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In November 2011, bills were introduced in both chambers of the United States Congress that, if passed, would enact the KHSA and a companion agreement that seeks to resolve other water-related conflicts and restore habitat in the Klamath basin. PacifiCorp expects that congressional hearings on the legislation may begin in 2012.

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 or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the OPUC, and is depositing the proceeds in a trust account maintained by the OPUC. PacifiCorp began collection of surcharges from California customers for their share of dam removal costs as approved by the California Public Utilities Commission ("CPUC") in January 2012 upon notification from the CPUC that two trust accounts had been established to collect the dam removal surcharge from California customers. PacifiCorp is authorized to collect the surcharge over the next nine years.

As of December 31, 2011, PacifiCorp's net utility plant included $124 million of costs associated with the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs. PacifiCorp has received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019 for those jurisdictions. PacifiCorp filed for consistent ratemaking treatment in the last Idaho general rate case, which was settled in January 2012. PacifiCorp expects to seek similar approval in Washington. As part of the July 2011 Utah general rate case settlement that was approved by the Utah Public Service Commission ("UPSC") in August 2011, PacifiCorp and the other parties to the settlement agreed to defer a decision regarding the acceleration of the depreciation rates for the Klamath hydroelectric system's four mainstem dams to a future rate proceeding, at which time Utah's $34 million share of associated relicensing and settlement costs would be addressed. In the 2012 Utah general rate case, PacifiCorp requested approval for Utah’s share of accelerated depreciation of the Klamath hydroelectric system’s four mainstem dams and associated relicensing and settlement costs.

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 $205 million over the next 10 years related to these licenses.

Commitments

PacifiCorp has the following firm commitments that are not reflected on the Comparative Balance Sheet. Minimum payments as of December 31, 2011 are as follows (in millions):

	2012	2013	2014	2015	2016	2017 and Thereafter	Total
Purchased electricity contracts	$ 245	$ 139	$ 97	$ 99	$ 79	$ 447	$ 1,106
Fuel contracts	677	633	599	503	399	2,390	5,201
Construction commitments	550	247	24	7	8	52	888
Transmission	108	98	84	62	54	702	1,108
Operating leases and easements	11	12	4	3	2	44	76
Maintenance, service and other contracts	32	22	17	7	4	49	131
Total commitments	$ 1,623	$ 1,151	$ 825	$ 681	$ 546	$ 3,684	$ 8,510

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 purchased electricity payments are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric 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 2011 and 2010 energy sources.

Fuel

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

Construction Commitments

PacifiCorp's construction commitments included in the table above relate to firm commitments and include the following major construction commitments.

- As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a commitment to the state regulatory commissions in all six states in which PacifiCorp has retail customers to invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. As of December 31, 2011, PacifiCorp had two remaining capital projects to complete associated with this commitment: (a) the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley that is expected to be placed in service in 2013 and (b) another segment of the Energy Gateway Transmission Expansion Program that is expected to be placed in service prior to 2021, depending on siting, permitting and construction schedules.

- PacifiCorp is constructing the 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility, which is expected to be placed in service in 2014.

Transmission

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

Operating Leases and Easements

PacifiCorp has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense totaled $18 million for 2011 and $15 million for 2010.

Maintenance, Service and Other Contracts

PacifiCorp has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

Guarantees

PacifiCorp has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on PacifiCorp's financial results.

(14) Preferred Stock

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, 2011 and 2010.

(15) Common Shareholder's Equity

In January 2012, PacifiCorp declared a dividend of $50 million, which was paid to PPW Holdings LLC, a direct wholly owned subsidiary of MEHC and PacifiCorp's direct parent company, in February 2012.

In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in April 2011.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in February 2011.

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized MEHC's 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, 2011, 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 45.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 44% for the year ending December 31, 2012 and thereafter. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2011, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 54.2%, and PacifiCorp would have been permitted to dividend $2.2 billion 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, 2011, 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) Supplemental Cash Flows Information

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

	2011	2010
Interest paid, net of amounts capitalized	$ 358	$ 331
Income taxes received, net[1]	$ 425	$ 393

(1) Includes amounts that may have arisen from subsidiaries as PacifiCorp files consolidated income tax returns.

Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 230	$ 216

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				(5,819,577)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				(1,142,322)
4	Total (lines 2 and 3)				(1,142,322)
5	Balance of Account 219 at End of Preceding Quarter/Year				(6,961,899)
6	Balance of Account 219 at Beginning of Current Year				(6,961,899)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				(2,093,533)
9	Total (lines 7 and 8)				(2,093,533)
10	Balance of Account 219 at End of Current Quarter/Year				(9,055,432)

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			(5,819,577)		
2		(7,825,262)	(7,825,262)		
3		7,825,262	6,682,940		
4			(1,142,322)	566,414,836	565,272,514
5			(6,961,899)		
6			(6,961,899)		
7		193,628	193,628		
8		(193,628)	(2,287,161)		
9			(2,093,533)	554,806,039	552,712,506
10			(9,055,432)		

Schedule Page: 122(a)(b) Line No.: 1 Column: g

Other Cash Flow Hedges relate to commodity derivatives.

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)	22,686,831,114	22,686,831,114
4	Property Under Capital Leases	65,393,121	65,393,121
5	Plant Purchased or Sold	-779,590	-779,590
6	Completed Construction not Classified	83,472,458	83,472,458
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	22,834,917,103	22,834,917,103
9	Leased to Others		
10	Held for Future Use	20,136,120	20,136,120
11	Construction Work in Progress	1,203,547,965	1,203,547,965
12	Acquisition Adjustments	159,175,508	159,175,508
13	Total Utility Plant (8 thru 12)	24,217,776,696	24,217,776,696
14	Accum Prov for Depr, Amort, & Depl	7,666,665,056	7,666,665,056
15	Net Utility Plant (13 less 14)	16,551,111,640	16,551,111,640
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,062,181,013	7,062,181,013
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	497,114,808	497,114,808
22	Total In Service (18 thru 21)	7,559,295,821	7,559,295,821
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	107,369,235	107,369,235
33	Total Accum Prov (equals 14) (22,26,30,31,32)	7,666,665,056	7,666,665,056

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	239,795,535	118,978
4	(303) Miscellaneous Intangible Plant	607,856,161	50,822,596
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	847,651,696	50,941,574
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	95,898,852	304,819
9	(311) Structures and Improvements	921,546,842	20,086,365
10	(312) Boiler Plant Equipment	3,520,898,916	491,282,155
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	896,985,415	90,367,508
13	(315) Accessory Electric Equipment	415,967,515	8,110,618
14	(316) Misc. Power Plant Equipment	33,234,020	562,115
15	(317) Asset Retirement Costs for Steam Production	42,346,157	3,606,532
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	5,926,877,717	614,320,112
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	26,123,587	11,493
28	(331) Structures and Improvements	113,026,083	28,700,745
29	(332) Reservoirs, Dams, and Waterways	326,583,937	34,977,839
30	(333) Water Wheels, Turbines, and Generators	112,432,922	9,112,227
31	(334) Accessory Electric Equipment	60,200,807	6,820,614
32	(335) Misc. Power PLant Equipment	2,360,733	46,389
33	(336) Roads, Railroads, and Bridges	16,323,315	589,496
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	657,051,384	80,258,803
36	D. Other Production Plant		
37	(340) Land and Land Rights	28,911,312	1,380
38	(341) Structures and Improvements	155,973,793	1,561,430
39	(342) Fuel Holders, Products, and Accessories	10,811,674	
40	(343) Prime Movers	2,513,737,706	20,819,891
41	(344) Generators	346,954,523	2,579,773
42	(345) Accessory Electric Equipment	234,749,420	2,321,798
43	(346) Misc. Power Plant Equipment	12,181,682	110,841
44	(347) Asset Retirement Costs for Other Production	5,109,797	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,308,429,907	27,395,113
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	9,892,359,008	721,974,028

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
51,378		-33,784,715	206,078,420		3
14,415,078		3,120,021	647,383,700		4
14,466,456		-30,664,694	853,462,120		5
					6
					7
		-3,196,087	93,007,584		8
1,280,750		1,352,126	941,704,583		9
124,477,850		-8,057,173	3,879,646,048		10
					11
34,308,816		-358,096	952,686,011		12
1,119,527		5,952,722	428,911,328		13
238,599		15,868	33,573,404		14
	-2,922,216		43,030,473		15
161,425,542	-2,922,216	-4,290,640	6,372,559,431		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
1,028		-83,279	26,050,773		27
611,148		241,325	141,357,005		28
5,233,587		-125,555	356,202,634		29
2,167,793		-127,157	119,250,199		30
583,244		-35,336	66,402,841		31
55,065			2,352,057		32
67,356			16,845,455		33
					34
8,719,221		-130,002	728,460,964		35
					36
			28,912,692		37
715,094		7,250,184	164,070,313		38
121,339		18,317	10,708,652		39
13,194,416		-24,204,642	2,497,158,539		40
3,221,924		6,020,871	352,333,243		41
279,783		12,451,786	249,243,221		42
62,570		166,984	12,396,937		43
			5,109,797		44
17,595,126		1,703,500	3,319,933,394		45
187,739,889	-2,922,216	-2,717,142	10,420,953,789		46

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	181,517,465	6,585,489
49	(352) Structures and Improvements	122,948,592	1,889,271
50	(353) Station Equipment	1,549,843,309	120,843,402
51	(354) Towers and Fixtures	863,436,957	121,134,025
52	(355) Poles and Fixtures	686,565,486	-36,751,094
53	(356) Overhead Conductors and Devices	912,469,174	-9,563,095
54	(357) Underground Conduit	3,259,452	166
55	(358) Underground Conductors and Devices	7,475,095	
56	(359) Roads and Trails	11,598,703	-12,022
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,339,114,233	204,126,142
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	52,837,393	2,627,987
61	(361) Structures and Improvements	74,675,982	3,939,729
62	(362) Station Equipment	817,421,421	43,613,791
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	942,088,822	52,031,610
65	(365) Overhead Conductors and Devices	648,849,674	20,286,125
66	(366) Underground Conduit	302,216,890	11,766,173
67	(367) Underground Conductors and Devices	718,645,076	22,802,968
68	(368) Line Transformers	1,097,798,842	46,967,729
69	(369) Services	581,777,749	23,644,523
70	(370) Meters	179,453,205	12,983,820
71	(371) Installations on Customer Premises	8,801,076	83,800
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,795,839	1,697,847
74	(374) Asset Retirement Costs for Distribution Plant	1,937,045	698,180
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,487,299,014	243,144,282
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	16,200,395	3,338,399
87	(390) Structures and Improvements	235,540,153	13,161,250
88	(391) Office Furniture and Equipment	77,219,598	10,829,521
89	(392) Transportation Equipment	98,768,642	8,925,864
90	(393) Stores Equipment	13,766,183	845,084
91	(394) Tools, Shop and Garage Equipment	61,822,342	3,356,837
92	(395) Laboratory Equipment	36,594,299	3,968,841
93	(396) Power Operated Equipment	132,526,576	28,146,900
94	(397) Communication Equipment	259,841,810	32,852,979
95	(398) Miscellaneous Equipment	6,906,051	833,772
96	SUBTOTAL (Enter Total of lines 86 thru 95)	939,186,049	106,259,447
97	(399) Other Tangible Property	274,422,093	24,292,229
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,213,647,890	130,551,676
100	TOTAL (Accounts 101 and 106)	21,780,071,841	1,350,737,702
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)	4,484,801	779,590
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	21,775,587,040	1,349,958,112

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
22,523		1,467,513	189,547,944		48
199,826		22,694,862	147,332,899		49
21,575,520		-35,984,018	1,613,127,173		50
1,130,245		1,342,202	984,782,939		51
3,223,897		-28,164	646,562,331		52
4,370,716		-1,791,984	896,743,379		53
			3,259,618		54
			7,475,095		55
			11,586,681		56
					57
30,522,727		-12,299,589	4,500,418,059		58
					59
9,436		245,472	55,701,416		60
144,171		4,644,520	83,116,060		61
5,965,866		-7,416,664	847,652,682		62
					63
6,427,662		1,381	987,694,151		64
3,732,883			665,402,916		65
1,751,221			312,231,842		66
2,911,463			738,536,581		67
8,921,800			1,135,844,771		68
741,827			604,680,445		69
16,914,183			175,522,842		70
97,819			8,787,057		71
					72
1,399,260			61,094,426		73
			2,635,225		74
49,017,591		-2,525,291	5,678,900,414		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
1,354			19,537,440		86
1,369,001		1,078,952	248,411,354		87
9,298,449		2,133,597	80,884,267		88
3,181,266		12,495	104,525,735		89
492,289		5,161	14,124,139		90
2,037,929		-6,428	63,134,822		91
2,551,746		17,120	38,028,514		92
9,829,916		140,466	150,984,026		93
2,697,836		8,392,562	298,389,515		94
452,882		21,914	7,308,855		95
31,912,668		11,795,839	1,025,328,667		96
7,364,897		-148,650	291,200,775		97
			39,748		98
39,277,565		11,647,189	1,316,569,190		99
321,024,228	-2,922,216	-36,559,527	22,770,303,572		100
					101
		-4,484,801	779,590		102
					103
321,024,228	-2,922,216	-32,074,726	22,769,523,982		104

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

Account	Description (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Transfers (f)	Balance at End of Year (g)
39921	Land Owned in Fee	$ 2,634,916	$ -	$ -	$ -	$ 2,634,916
39922	Land Rights	52,550,647	-	-	-	52,550,647
39930	Structures	40,641,166	380,629	108,636	(637,769)	40,275,390
39941	Surface-Plant Equipment	12,131,316	110,971	150,851	644,389	12,735,825
39944	Surface-Electric Power Facilities	3,424,575	-	-	-	3,424,575
39945	Underground-Coal Mine Equipment	72,452,088	4,343,036	3,622,781	-	73,172,343
39946	Longwall Shields	15,511,575	8,970,139	-	-	24,481,714
39947	Longwall Equipment	4,461,627	6,034,905	2,631,424	-	7,865,108
39948	Mainline Extension	18,640,302	1,011,392	752,495	-	18,899,199
39949	Section Extension	4,203,530	1,935,527	-	-	6,139,057
39951	Vehicles	1,237,982	-	-	-	1,237,982
39952	Heavy Construction Equipment	5,305,731	852,514	(152,962)	(152,962)	6,158,245
39960	Miscellaneous General Equipment	2,236,016	147,065	45,082	(6,620)	2,331,379
39961	Computers-Mainframe	568,271	26,413	206,590	4,312	392,406
39970	Mine Development and Road Extension	38,151,569	263,308	-	-	38,414,877
399915	Coal Mine Asset Retirement Obligations	270,782	216,330	-	-	487,112
		$274,422,093	$24,292,229	$7,364,897	$(148,650)	$291,200,775

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

See footnote line 97, column b.

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

See footnote line 97, column b.

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

See footnote line 97, column b.

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

See footnote line 97, column b.

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

Refer to page 108, Important Changes During the Quarter/Year, Item 3, of this Form No. 1.

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

Refer to page 108, Important Changes During the Quarter/Year, Item 3, of this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	2023-2028	953,014
4	Barnes Butte Substation	2007	2023	746,268
5	Wild Horse Wind Plant	2007	2022	6,763,094
6	Twelve Mile Wind Plant	2007	2021	2,160,207
7	Jumbers Point Substation	2008	2016	1,173,276
8	Mountain Green Substation	2009	2025	284,996
9	Hoggard Substation	2009	2025	254,397
10	Oquirrh-Terminal 345-kV Transmission Line	2009	2015	396,020
11	Bend Service Center	2010	2021	3,507,838
12	Legacy Substation	2010	2020	562,276
13	Aeolus Substation	2011	2018	1,014,053
14	Anticline Substation	2011	2018	964,505
15	Populus Substation	2011	2021	254,753
16	Snyderville Substation	2011	2018	253,401
17				
18	Miscellaneous, each under $250,000			848,022
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			20,136,120

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 2022, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Expansion Program.

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

Land purchased for wind farms with an estimated construction date of 2021, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Expansion Program.

Schedule Page: 214 Line No.: 16 Column: a

In March 2011, Snyderville Substation was transferred from account 101, Electric plant in service to account 105, Electric plant held for future use.

Schedule Page: 214 Line No.: 18 Column: c

Various dates and plans.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 (Utah portion)	34,462,143
3	Mobile Radio Purch-Implement VHF Spectrum	3,153,235
4	Hunter Adobe Wash Regulating Facility	2,919,994
5	SAP license and maintenance enhancements	1,726,242
6	IT-Mobility Upgrade / Click Replacement	1,148,695
7		
8	Production:	
9	Lake Side 2 Development	187,082,403
10	Naughton U1 Flue Gas Desulfurization System	99,062,587
11	Dave Johnston U4 SO2 & PM Emission Control Upgrades	91,410,539
12	North Umpqua River System Relicensing Implementation	62,817,337
13	Lewis River System Relicensing Implementation	55,759,180
14	Hunter U1 SO2 & PM Emission Control Upgrades	41,023,226
15	Hunter U3 Turbine Upgrade HP/IP/LP	17,109,688
16	Blundell Proofing Well Integration	17,019,286
17	Jim Bridger U2 Turbine Upgrade HP/IP/LP	11,598,127
18	Hunter U2 SO2 & PM Emission Control Upgrades	10,206,741
19	Ashton Dam Seepage Control	7,351,147
20	Naughton U3 Baghouse, FGD Upgrade, SCR System	4,511,391
21	Rogue River System Relicensing Implementation	4,377,509
22	Huntington U2 Steam Inerting for Coal Mills	3,768,239
23	Generation Compliance Initiative Hardware	3,537,516
24	Dave Johnston - Replace Retro Cooling Tower	2,547,145
25	Dave Johnston U4 - Finishing Superheater Replacement	2,157,110
26	Naughton FGD Reagent Loadout Facility	2,104,227
27	Swift 1 Station Service/Generator Breaker	1,848,236
28	Currant Creek 2 Development	1,824,925
29	Dave Johnston U4 - Platen SSH Replace	1,780,501
30	Dave Johnston - Fire Protection Repl Tripper Deck Booster Pumps	1,430,298
31	Huntington U2 Duct Replacements	1,397,839
32	Hunter U3 Wet Stack Upgrades	1,382,979
33	Merwin Spillway Tainter Gate Rehab	1,016,501
34		
35	Transmission:	
36	Mona-Oquirrh 345kV/500kV Transmission Line	127,997,118
37	Energy Gateway Preliminary Engineering and Permitting	54,863,681
38	Sigurd-Red Butte-Crystal 345kV Line	28,334,122
39	Aeolus Clover 500kV Line	25,007,520
40	Terminal Substation 345-138kV Trnsf to 700 MVA	19,755,817
41	Southwest WY Silver Creek Build 138kV Line	17,039,715
42	Clover Substation install 345-138kV Sub & Lines	11,157,079
43	TOTAL	1,203,547,965

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Line 3 Convert to 115kV	7,009,435
2	Dave Johnston to Casper 230kV No 1&2 Line Rebuild	6,983,367
3	Line 37 Convert to 115kV Build Nickel Mt Substation	6,672,433
4	Oquirrh-Terminal 345kV Line	6,032,738
5	Facebook Data Center Phase 2 Tom McCall Industrial Park - 115kV Project	5,076,647
6	Wallula-McNary 230kV Line	4,253,558
7	West Point-New 138kV Line & 40 MVA Substation	3,812,628
8	TOT 4A-4B Transmission Path Transfer Capacity	3,607,563
9	Vantage-Pomona Heights 230kV Line	2,775,035
10	Cameron-Milford 138kV Transmission	2,756,659
11	Union Gap Pacific 115kV Reconductor	2,449,147
12	Ben Lomond add 2nd 345-139kV Transformer	2,347,658
13	Carbon County System Reinforcement	2,140,114
14	Ashley Substation-Install 3 Stage 29.8 MVAR Cap	2,061,757
15	Three Peaks Substation: Install 345kV Sub	1,773,266
16	Lake Side 2 Interconnect Q0301	1,673,116
17	Powerdale Repl Sub w-69kV Trans Switchyard Station	1,516,215
18	Two Elks Intercon at Tri County Switchyard	1,509,017
19	Jordan 2 Instl 138-12.5kV 40 MVA Trns-Fdr	1,411,261
20	Cove - Cove Tap 69kV 1.9 Miles Trans Line	1,289,271
21	WY-NERC Facility Rating Project-Phase II	1,257,397
22	UT-NERC Facility Rating Project-Phase II	1,234,159
23		
24	Distribution:	
25	Nibley 138-12.5kV Substation	13,363,014
26	City Creek Center (SLC) New 40 MW Dev for PRI	8,930,441
27	Farmington Substation add 2nd 138-12.5kV Transfmr	3,756,091
28	Fort Douglas-New 138-12.5kV Substation & Transfmr	1,642,209
29	Deschutes Substation Inc Cap Repl Transformer	1,480,724
30	Smithfield Substation add New Feeder 13	1,370,453
31	Lassen Substation Constr New 115-12.5kV	1,164,562
32		
33	General:	
34	Mobile Radio Replacement Project	38,033,613
35	Deer Creek Mine-Reconstruct Longwall System	1,203,876
36		
37	Miscellaneous Projects each under $1,000,000	101,270,503
38		
39		
40		
41		
42		
43	TOTAL	1,203,547,965

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	6,893,664,705	6,893,664,705		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	544,830,198	544,830,198		
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):	28,652,845	28,652,845		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	573,483,043	573,483,043		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	307,228,919	307,228,919		
13	Cost of Removal	78,411,893	78,411,893		
14	Salvage (Credit)	9,003,170	9,003,170		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	376,637,642	376,637,642		
16	Other Debit or Cr. Items (Describe, details in footnote):	-28,329,093	-28,329,093		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,062,181,013	7,062,181,013		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,465,684,624	2,465,684,624		
21	Nuclear Production				
22	Hydraulic Production-Conventional	254,117,565	254,117,565		
23	Hydraulic Production-Pumped Storage				
24	Other Production	480,305,750	480,305,750		
25	Transmission	1,224,958,546	1,224,958,546		
26	Distribution	2,160,071,159	2,160,071,159		
27	Regional Transmission and Market Operation				
28	General	477,043,369	477,043,369		
29	TOTAL (Enter Total of lines 20 thru 28)	7,062,181,013	7,062,181,013		

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

Generally, 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	$ 9,898,481
Account 143 Joint Owner Receivable - depreciation expense billed to joint owners	181,962
ARO asset depreciation recorded as a regulatory asset or liability	2,892,371
Transportation depreciation allocated to O&M and construction based on usage activity	14,396,524
Account 503 Blundell depletion	185,368
Account 503 Blundell depreciation	1,098,139
Total other accounts	$28,652,845

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

Represents the reclassification of accrued removal and spend on asset retirement obligations that were included in lines 3 and 13.	$(45,267,623)
Other items including: - Recovery from third parties for asset relocations and damaged property - Insurance recoveries - Adjustments of reserve related to electric plant sold - Reclassifications from electric plant	16,938,530
Total Other Debit or Cr. Items	$(28,329,093)

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.	1973		
2	Common Stock			1
3	Paid-in Capital			47,960,000
4	Undistributed Subsidiary Earnings			130,708,101
5	SUBTOTAL			178,668,102
6				
7	ENERGY WEST MINING COMPANY	1990		
8	Common Stock			1,000
9	SUBTOTAL			1,000
10				
11	CENTRALIA MINING COMPANY	1990		
12	Common Stock			1,000
13	SUBTOTAL			1,000
14				
15	GLENROCK COAL COMPANY	1991		
16	Common Stock			1
17	SUBTOTAL			1
18				
19	INTERWEST MINING COMPANY	1992		
20	Common Stock			1,000
21	SUBTOTAL			1,000
22				
23	TRAPPER MINING INC.	1992		
24	Members' Equity			6,038,000
25	Undistributed Subsidiary Earnings			5,463,358
26	SUBTOTAL			11,501,358
27				
28	PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY	1994		
29	Paid-in Capital			14,719,625
30	Undistributed Subsidiary Earnings			6,232,713
31	SUBTOTAL			20,952,338
32				
33	FOSSIL ROCK FUELS, LLC	2011		
34	Paid-in Capital			
35	Undistributed Subsidiary Earnings			
36	SUBTOTAL			
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 89,040,627		TOTAL	211,124,799

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
9,537,656		140,245,757		4
9,537,656		188,205,758		5
				6
				7
		1,000		8
		1,000		9
				10
				11
		1,000		12
		1,000		13
				14
				15
		1		16
		1		17
				18
				19
		1,000		20
		1,000		21
				22
				23
		6,038,000		24
422,843		5,886,201		25
422,843		11,924,201		26
				27
				28
		14,719,625		29
-447,546		5,785,167		30
-447,546		20,504,792		31
				32
				33
		20,320,000		34
-1,484		-1,484		35
-1,484		20,318,516		36
				37
				38
				39
				40
				41
9,511,469		240,956,268		42

Schedule Page: 224 Line No.: 1 Column: a

Pacific Minerals, Inc. is a wholly owned subsidiary of PacifiCorp that holds a two-thirds ownership interest in Bridger Coal Company, a coal-mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company.

Schedule Page: 224 Line No.: 2 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 224 Line No.: 3 Column: d

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 224 Line No.: 8 Column: d

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 224 Line No.: 12 Column: d

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 224 Line No.: 25 Column: d

Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	188,493,087	236,891,214	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)	71,053,270	106,787,597	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	93,357,638	65,342,036	Electric
8	Transmission Plant (Estimated)	718,031	507,347	Electric
9	Distribution Plant (Estimated)	16,656,313	17,729,257	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	4,620,906	6,198,530	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	186,406,158	196,564,767	
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)	374,899,245	433,455,981	

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

Mining materials and supplies	$	4,477,840
General plant materials and supplies		143,066
	$	4,620,906

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

Mining materials and supplies	$	5,964,328
General plant materials and supplies		234,202
	$	6,198,530

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	186,325.00		156,647.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Adjustments	-58.00			
10					
11					
12					
13					
14					
15	Total	-58.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	58,004.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	See footnote for details	47,641.00			
23					
24					
25					
26					
27					
28	Total	47,641.00			
29	Balance-End of Year	80,622.00		156,647.00	
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				

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.

2013		2014		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
156,646.00		156,645.00		4,035,430.00		4,691,693.00		1
								2
								3
				156,644.00		156,644.00		4
								5
								6
								7
								8
						-58.00		9
								10
								11
								12
								13
								14
						-58.00		15
								16
								17
						58,004.00		18
								19
								20
								21
						47,641.00		22
								23
								24
								25
								26
								27
						47,641.00		28
156,646.00		156,645.00		4,192,074.00		4,742,634.00		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

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

The names of purchasers/transferees and the number of allowances disposed of during the year ended December 31, 2011 are as follows:

Pepco Energy Services, Inc.	1,000
Ohio Valley Electric Corporation	15,515
Constellation Energy Commodities Group, Inc.	20,000
Gulf Power Company	1,126
Duke Energy Commercial Asset Management, Inc.	10,000
	47,641

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant: Trojan Nuclear	135,566		407	135,566	
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						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	135,566			135,566	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	AREF 618363	141	561.6	141	456
3	AREF 642592	14,371	561.6	14,371	456
4	AREF 645170	10,648	561.6	10,648	456
5	AREF 654674	19,859	561.6	19,859	456
6	AREF 676490	8,095	561.6	8,095	456
7	AREF 686257	11,678	561.6	11,678	456
8	AREF 688430	7,201	561.6	5,448	456
9	AREF 690566	16,875	561.6	16,875	456
10	AREF 690831	19,418	561.6	19,418	456
11	AREF 709133	11,517	561.6	11,517	456
12	AREF 709137	10,111	561.6	10,111	456
13	AREF 719404	6,557	561.6	6,557	456
14	AREF 719406	6,646	561.6	6,646	456
15	AREF 723544	6,438	561.6	6,438	456
16	AREF 723846	10,454	561.6	10,454	456
17	AREF 739339	4,643	561.6	4,643	456
18	Legacy Study #1	4,419	561.6	4,419	456
19	Legacy Study #2	2,653	561.6	2,653	456
20	AREF 637974	122	561.6		
21	**Generation Studies**				
22	GIQ0170	29	561.7	29	456
23	GIQ0187	39	561.7	39	456
24	GIQ0187-189	1,006	561.7	1,006	456
25	GIQ0188	14	561.7	14	456
26	GIQ0189	14	561.7	14	456
27	GIQ0190	227	561.7	227	456
28	GIQ0193	14	561.7	14	456
29	GIQ0230	76	561.7	76	456
30	GIQ0255	21,146	561.7	21,146	456
31	GIQ0256	120	561.7	120	456
32	GIQ0260-263	38,173	561.7	38,173	456
33	GIQ0276	10,281	561.7	10,281	456
34	GIQ0289	(74)	561.7	(74)	456
35	GIQ0290	1,297	561.7	1,297	456
36	GIQ0291	1,631	561.7	1,631	456
37	GIQ0292	13,239	561.7	13,239	456
38	GIQ0295	941	561.7	941	456
39	GIQ0299	5,131	561.7	5,131	456
40	GIQ0303	208	561.7	208	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 637977	243	561.6		
3	AREF 648013	1,962	561.6		
4	AREF 675661	3,990	561.6		
5	AREF 675662	3,990	561.6		
6	AREF675663	4,066	561.6		
7	AREF 675664	3,762	561.6		
8	AREF 675665	3,458	561.6		
9	AREF 680400	1,093	561.6		
10	AREF 683060	2,739	561.6		
11	AREF 704328	6,105	561.6		
12	AREF 659527	3,728	561.6		
13	AREF 673963	3,636	107		
14	AREF 659527	2,283	107		
15	AREF 681628	4,595	107		
16	AREF 684287	3,332	107		
17	AREF 686836	3,743	107		
18	AREF 709355	5,935	107		
19	AREF 728784	5,687	107		
20	AREF 740690	2,104	107		
21	**Generation Studies**				
22	GIQ0306	12,354	561.7	12,354	456
23	GIQ0310	4,026	561.7	4,026	456
24	GIQ0311	12,474	561.7	12,474	456
25	GIQ0313	2,930	561.7	2,930	456
26	GIQ0314	3,758	561.7	3,758	456
27	GIQ0315	12,405	561.7	12,405	456
28	GIQ0316	2,438	561.7	2,438	456
29	GIQ0322	17,814	561.7	17,814	456
30	GIQ0323	7,579	561.7	7,579	456
31	GIQ0324	6,044	561.7	6,044	456
32	GIQ0326	16,092	561.7	16,092	456
33	GIQ0332	8,411	561.7	8,411	456
34	GIQ0333	10,557	561.7	10,557	456
35	GIQ0334	80	561.7	80	456
36	GIQ0335	4,351	561.7	4,351	456
37	GIQ0341	5,527	561.7	5,527	456
38	GIQ0345	282	561.7	282	456
39	GIQ0346	185	561.7	185	456
40	GIQ0347	5,678	561.7	5,678	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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 741886	3,401	107		
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0348	5,955	561.7	5,955	456
23	GIQ0349	2,774	561.7	2,774	456
24	GIQ0350	7,413	561.7	7,413	456
25	GIQ0351	31,173	561.7	31,173	456
26	GIQ0352	2,527	561.7	2,527	456
27	GIQ0353	1,701	561.7	1,701	456
28	GIQ0354	6,781	561.7	6,781	456
29	GIQ0355	720	561.7	720	456
30	GIQ0356	12,547	561.7	12,547	456
31	GIQ0357	10,594	561.7	10,594	456
32	GIQ0358	707	561.7	707	456
33	GIQ0359	15,109	561.7	15,109	456
34	GIQ0360	18,538	561.7	18,538	456
35	GIQ0361	1,135	561.7	1,135	456
36	GIQ0362	955	561.7	955	456
37	GIQ0363	4,275	561.7	4,275	456
38	GIQ0364	21,228	561.7	21,228	456
39	GIQ0365	4,427	561.7	4,427	456
40	GIQ0366	14,444	561.7	14,444	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0367	43,293	561.7	43,293	456
23	GIQ0368	5,334	561.7	5,334	456
24	GIQ0369	1,013	561.7	1,013	456
25	GIQ0370	3,968	561.7	3,968	456
26	GIQ0371	1,517	561.7	1,517	456
27	GIQ0372	17,719	561.7	17,719	456
28	GIQ0373	13,628	561.7	13,628	456
29	GIQ0374	17,835	561.7	17,835	456
30	GIQ0375	25,874	561.7	25,874	456
31	GIQ0376	17,254	561.7	17,254	456
32	GIQ0377	41,870	561.7	41,870	456
33	GIQ0378	15,879	561.7	15,879	456
34	GIQ0379	2,401	561.7	2,401	456
35	GIQ0380	2,272	561.7	2,272	456
36	GIQ0381	2,132	561.7	2,132	456
37	GIQ0382	2,361	561.7	2,361	456
38	GIQ0383	2,413	561.7	2,413	456
39	GIQ0384	13,302	561.7	13,302	456
40	GIQ0385	11,167	561.7	11,167	456

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0386	14,972	561.7	14,972	456
23	GIQ0387	2,562	561.7	2,562	456
24	GIQ0388	622	561.7	622	456
25	GIQ0389	13,920	561.7	13,920	456
26	GIQ0390	648	561.7	648	456
27	GIQ0392	7,235	561.7	7,235	456
28	GIQ0393	10,431	561.7	10,431	456
29	GIQ0394	9,003	561.7	9,003	456
30	GIQ0395	11,893	561.7	11,893	456
31	GIQ0396	4,700	561.7	4,700	456
32	GIQ0397	5,386	561.7	5,386	456
33	GIQ0398	5,740	561.7	5,740	456
34	GIQ0399	1,845	561.7	1,845	456
35	GIQ0400	3,357	561.7	3,357	456
36	GIQ0401	4,957	561.7	4,957	456
37	GIQ0403	1,909	561.7	1,909	456
38	GIQ0404	1,675	561.7	1,675	456
39	GIQ0405	1,814	561.7	1,814	456
40	PRE-QUEUE	587	561.7	587	456

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Customer Studies Accruals	(3,453)	561.7		
23	GIQ1256	27,385	561.7		
24	GIQ1293	5,308	561.7		
25	GIQ0301	2,751	107		
26	GIQ1256	4,486	107		
27	GIQ0402	532	107		
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	DSM Regulatory Asset Actuals - CA	(3,193,591)	1,555,031	908,431	1,368,577	-3,007,137
2	DSM Regulatory Asset Accruals - CA	82,294	165,865			248,159
3	DSM Regulatory Asset Actuals - ID	5,339,142	2,696,505	908	5,682,037	2,353,610
4	DSM Regulatory Asset Accruals - ID	327,207	53,773			380,980
5	DSM Regulatory Asset Actuals - UT	2,284,513	43,653,932	908,431	54,626,479	-8,688,034
6	DSM Regulatory Asset Accruals - UT	4,176,467		908	311,407	3,865,060
7	DSM Regulatory Asset Actuals - WA	595,391	9,195,525	908	8,883,683	907,233
8	DSM Regulatory Asset Accruals - WA	437,274	93,721			530,995
9	DSM Regulatory Asset Actuals - WY	(4,000,836)	3,863,183	908,431	156,112	-293,765
10	DSM Regulatory Asset Accruals - WY	362,894	69,264			432,158
11	DSM Regulatory Asset Actuals - OR		26,627			26,627
12	Alternative Rate For Energy (CARE) - CA	253,983	78,451	142	570,066	-237,632
13	2006 Transition Plan - OR (2)	2,969,259	38,087	920	2,094,839	912,507
14	2006 Transition Plan - CA (1)	222,772		920	178,218	44,554
15	Deferred Income Taxes Electric	448,480,778		282,283	4,592,944	443,887,834
16	Deferral of Interest on Uncertain Tax Positions-UT	1,444,909	527,718			1,972,627
17	Deferral of Interest on Uncertain Tax Positions-WY	372,132	159,202			531,334
18	Deferral of Interest on Uncertain Tax Positions-ID		271,404			271,404
19	Tax Revenue Requirement Adjustment - WY	99,955			29,424	70,531
20	Deferred Excess Net Power Costs - OR	3,526,084	27,795	555	3,615,312	-61,433
21	Deferred Excess Net Power Costs/ECAC - CA	1,909,644	1,242,038	555	1,044,586	2,107,096
22	Deferred Excess Net Power Costs - WY 2009	1,596,942	2,840	555	1,599,782	
23	Deferred Excess Net Power Costs - WY 2010	14,492,513	91,585	555	11,335,035	3,249,063
24	Deferred Excess Net Power Costs - WY 2011		32,442,978			32,442,978
25	Deferred Excess Net Power Costs - WA Hydro (3)	2,670,016	139,856	555	1,993,184	816,688
26	Deferred Excess Net Power Costs - ID 2009	487,229	2,244	555	489,473	
27	Deferred Excess Net Power Costs - ID 2010	11,434,111	372,829	555	6,757,650	5,049,290
28	Deferred Excess Net Power Costs - ID 2011	1,035,589	17,176,323			18,211,912
29	Deferred Excess Net Power Costs - UT		67,787,260			67,787,260
30	Deferred Excess RECs in Rates - UT			456	16,637	-16,637
31	Deferred Excess RECs in Rates - WA		681,343			681,343
32	Deferred Excess RECs in Rates - WY			456	517,165	-517,165
33	Environmental Costs (10)	8,296,641	3,124,379	925	1,752,910	9,668,110
34	Environmental Costs - WA (10)	(650,117)	127,889	925	228,059	-750,287
35	Reg Asset - Environmental Costs	9,370,862	3,184,967			12,555,829
36	Cholla Plant Transaction Costs (26)	6,179,329	183,792	557	1,122,424	5,240,697
37	Washington Colstrip #3 (22)	526,259		456	52,188	474,071
38	Unamortized Contract Values (5)		189,323,843	242,253	2,374,710	186,949,133
39	Derivative Net Regulatory Asset	487,295,264			224,102,593	263,192,671
40	Asset Retirement Obligations Regulatory Difference	68,251,011			19,292,273	48,958,738
41	Pension/Other Postretirement	596,639,721	168,804,000		36,946,065	728,497,656
42	RTO Grid West N/R - OR (3)	738,048	10,823	904	393,344	355,527
43	RTO Grid West N/R - ID (5)	27,162		904	27,162	
44	TOTAL	1,737,446,767	572,862,336		435,773,432	1,874,535,671

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Independent Evaluator Fee - UT	(16,501)	92,241			75,740
2	Deferred Independent Evaluator Fee - OR (1)	539,513	22,227	557	753,634	-191,894
3	Deferred Intervenor Funding Grants - CA		32,885			32,885
4	Deferred Intervenor Funding Grants - ID (2)	43,797	39,000	928	24,095	58,702
5	Deferred Intervenor Funding Grants - OR	37,082	308,561			345,643
6	BPA Balancing Account - ID	2,685,242		440,442	1,390,488	1,294,754
7	Renewable Adjustment Clause - OR (1)	629,955	4,564		643,335	-8,816
8	Goodnoe Hills Settlement - WY (24)	488,750		930.2	21,250	467,500
9	Lake Side Settlement - WY (39)	1,005,095		930.2	27,919	977,176
10	SB 408 Regulatory Asset - OR (1)	1,095,545	15,747,236		9,934,873	6,907,908
11	SB 408 Regulatory Asset - MCBIT (1)	(189,015)	242,168	431,426.5	102,547	-49,394
12	Chehalis Generating Facility Deferral - WA (6)	15,000,000			3,000,000	12,000,000
13	Powerdale Decommissioning - ID (10)	304,766	25,772	407.3	117,818	212,720
14	Powerdale Decommissioning - OR (1.5)	493,016		407.3	493,016	
15	Powerdale Decommissioning - WA (3)	851,788		407.3	212,947	638,841
16	Powerdale Decommissioning - WY (1)	34,392		407.3	34,392	
17	Powerdale Decommissioning - CA (2)		70,081	407.3	37,012	33,069
18	Deferred Advertising Costs - WY (1)	52,198		909	52,198	
19	Major Plant Additions Deferral - UT (1)	15,724,521	1,696,342		17,420,863	
20	Solar Feed-In Tariff Deferral - OR	226,622	1,043,825			1,270,447
21	Solar Feed-In Tariff Deferral - CA		380,507	407.3	626,859	-246,352
22	Tax Adj on Postretirement Benefits - CA (3)	383,431		410.1,283	127,808	255,623
23	Tax Adj on Postretirement Benefits - ID (4)	819,988		410.1,283	204,997	614,991
24	Tax Adj on Postretirement Benefits - OR	4,471,643				4,471,643
25	Tax Adj on Postretirement Benefits - UT (4)	5,891,250		410.1,283	1,571,001	4,320,249
26	Tax Adj on Postretirement Benefits - WA	1,126,592		410.1,283	1,126,592	
27	Tax Adj on Postretirement Benefits - WY (4)	2,121,315	201,064	410.1,283	644,976	1,677,403
28	Storm Damage Deferral - CA (1)	1,230,000		924	1,164,006	65,994
29	Deferred Overburden Cost - ID	249,097	963,999	501	1,037,044	176,052
30	Deferred Overburden Cost - WY	665,891	2,671,531	501	2,849,424	487,998
31	Regulatory Assets - Reclassifications	7,399,943	2,145,261			9,545,204
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,737,446,767	572,862,336		435,773,432	1,874,535,671

Schedule Page: 232 Line No.: 15 Column: a

Weighted average remaining life is 33 years. Amounts primarily represent income tax benefits related to certain property-related basis differences and other various items that PacifiCorp is required to pass on to its customers.

Schedule Page: 232 Line No.: 19 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232 Line No.: 20 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 21 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 22 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 23 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

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

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 26 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

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

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 28 Column: a

Net power costs are deferred in accordance with established adjustment mechanisms and amortized over a 12-month period.

Schedule Page: 232 Line No.: 38 Column: a

Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value.

Schedule Page: 232 Line No.: 39 Column: a

Weighted average remaining life is 1 year.

Schedule Page: 232 Line No.: 39 Column: d

Account 175, Derivative instrument assets
Account 244, Derivative instrument liabilities
Account 182.3, Other regulatory assets

Schedule Page: 232 Line No.: 40 Column: d

Account 108, Accumulated provision for depreciation of electric utility plant
Account 230, Asset retirement obligations
Account 403, Depreciation expense

Schedule Page: 232 Line No.: 41 Column: a

Weighted average remaining life is 10 years. Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

Schedule Page: 232 Line No.: 41 Column: d

Pensions and benefits are associated with labor and generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 232.1 Line No.: 7 Column: d

Account 440, Residential sales

Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 10 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 12 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 19 Column: d

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting

Schedule Page: 232.1 Line No.: 31 Column: f

The following schedule summarizes regulatory assets reclassifications:

	As of December 31, 2011
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset Actuals - CA	$ 3,007,137
DSM Regulatory Asset Accruals - CA	(248,159)
DSM Regulatory Asset Actuals - UT	8,688,034
DSM Regulatory Asset Accruals - UT	(3,865,060)
Alternative Rate For Energy (CARE) - CA	237,632
Deferred Excess RECs in Rates - UT	16,637
Deferred Excess RECs in Rates - WY	517,165
Deferred Excess Net Power Costs - OR	61,433
Renewable Adjustment Clause - OR	8,816
Deferred Independent Evaluator Fee - OR	191,894
Solar Feed-In Tariff Deferral - CA	246,352
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Property Insurance Reserve - UT	683,323
	$ 9,545,204

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 (21)	973,114		557	137,381	835,733
2						
3	Lacomb Irrigation (24)	506,730		557	45,720	461,010
4						
5	Bogus Creek (41)	1,200,560		557	41,280	1,159,280
6						
7	Mead Phoenix Availability and					
8	Transmission Charge (50)	13,756,760		565	377,760	13,379,000
9						
10	TGS Buyout (23)	140,551		557	15,473	125,078
11						
12	Point to Point Transmission	4,476,900	748,663	142	2,183,579	3,041,984
13						
14	Jim Boyd Hydro Buyout (11)	255,485		557	82,860	172,625
15						
16	Hermiston Swap (40)	4,392,484		557	171,693	4,220,791
17						
18	LGIA LT Transmission Prepaid	3,086,717	108,389	565, 419	1,248,826	1,946,280
19						
20	Deferred Longwall Costs	1,105,396	2,992,997	151	3,179,255	919,138
21						
22	Deferred Coal Costs - Arch					
23	Settlement (3)	63,030	2,934	151	65,964	
24						
25	Deferred Coal Costs - Wyodak					
26	Settlement (22)	4,022,182		151	335,182	3,687,000
27						
28	Deferred Coal Costs - Naughton					
29	Settlement (7)	8,256,923		151	1,376,154	6,880,769
30						
31	Deferred Colstrip Plant					
32	Costs (5)	1,500,000		501	275,000	1,225,000
33						
34	LT Lease Commissions					
35	Prepaids (10)	649,659		931	92,820	556,839
36						
37	RTO Grid West N/R write-off -					
38	WA (5)	23,470		904	23,470	
39						
40	Lake Side Maintenance Prepaids	14,720,749	4,822,317	107	8,415,366	11,127,700
41						
42	Chehalis Maintenance Prepaids	5,777,606	1,651,887			7,429,493
43						
44	Currant Creek Maint. Prepaids	5,465,610	6,019,326			11,484,936
45						
46	Lease Incentives (10)	1,115,229		454	155,120	960,109
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	86,478,095				88,864,233

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	Credit Agreement Costs (5)	1,051,143		427, 431	456,630	594,513
3						
4	PCRB LOC/SBBPA Costs (5)	413,129	22,772	427	296,309	139,592
5						
6	PCRB Mode Conversion Costs (11)	413,486		427	144,442	269,044
7						
8	'94 Series Restruct. Costs (14)	988,431		427	116,981	871,450
9						
10	Deferred Financing Costs (13)	1,000	432,936	181	433,936	
11						
12	Deferred S-3 Shelf Regis. Costs	784	25,836	186	26,620	
13						
14	LT Prepaid IBEW 57 Pension					
15	Contribution		5,651,545			5,651,545
16						
17	BPA LT Transmission Prepaid	9,133,961	313,382	565	863,304	8,584,039
18						
19	Emission Reduction Credits	2,956,980	2,040,000	549	2,365,584	2,631,396
20						
21	Unamortized contract values		478,212			478,212
22						
23	Sales of Electric Utility					
24	Facilities & Properties	27	1,650			1,677
25						
26	Other Current Deferred Charges	29,999	1			30,000
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	86,478,095				88,864,233

Schedule Page: 233.1 Line No.: 26 Column: b
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 233.1 Line No.: 26 Column: c
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 233.1 Line No.: 26 Column: d
Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 233.1 Line No.: 26 Column: e
Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	187,114,591	209,587,367
3	Derivative Contracts	184,509,824	99,884,250
4	Regulatory Liabilities	25,903,274	43,186,293
5			
6			
7	Other	191,062,227	286,987,845
8	TOTAL Electric (Enter Total of lines 2 thru 7)	588,589,916	639,645,755
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)	588,589,916	639,645,755

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	MidAmerican Energy Holdings Company			
3	indirectly owns all of the shares of			
4	PacifiCorp's outstanding common stock.			
5	Therefore, there is no public market for			
6	PacifiCorp's common stock.			
7				
8	TOTAL COMMON STOCK	750,000,000		
9				
10				
11	Preferred Stock (Account 204):			
12	5% Cumulative Preferred	126,533	100.00	110.00
13				
14	Serial Preferred, Cumulative:	3,500,000		
15	4.52% Series		100.00	103.50
16	7.00% Series		100.00	
17	6.00% Series		100.00	
18	5.00% Series		100.00	100.00
19	5.40% Series		100.00	101.00
20	4.72% Series		100.00	103.50
21	4.56% Series		100.00	102.34
22	No Par Serial Preferred	16,000,000		
23	TOTAL PREFERRED STOCK	19,626,533		
24				
25				
26				
27				
28				
29				
30				
31				
32				
33	Authorized and Unissued Capital Stock			
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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
						6
						7
357,060,915	3,417,945,896					8
						9
						10
						11
126,243	12,624,300					12
						13
						14
2,065	206,500					15
18,046	1,804,600					16
5,930	593,000					17
41,908	4,190,800					18
65,959	6,595,900					19
65,854	6,585,400					20
81,326	8,132,600					21
						22
407,331	40,733,100					23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

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

This class of 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.: 17 Column: d

This series of preferred stock is not redeemable.

Schedule Page: 250 Line No.: 33 Column: a

Authorizations for the issuance of common stock 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, 2011, PacifiCorp had regulatory approval from the aforementioned commissions for the issuance of 30,000,000 shares of common stock out of the 750,000,000 authorized (357,060,915 outstanding) by PacifiCorp's articles of incorporation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	1,089,950,000
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	Gain on repurchase of preferred stock	166,025
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	1,102,229,981

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 certain benefit plan obligations and assets 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"). No capital contributions were made by MEHC to PacifiCorp during the year ended December 31, 2011.

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, which invested in Scottish Power plc stock.

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

Represents amounts associated with IRC Section 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.

Schedule Page: 253 Line No.: 10 Column: b

Represents gain on PacifiCorp's repurchase of certain shares of its preferred stock in May 2010.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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%	98,049
5	4.52% Serial	9,676
6	4.72% Serial	28,596
7	4.56% Serial	47,177
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	41,284,560

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	7.978% Series due October 1, 2011	4,422,000	
5	6.90% Series due November 15, 2011	500,000,000	3,567,009
6			1,735,000 D
7	8.493% Series due October 1, 2012	19,772,000	
8	8.797% Series due October 1, 2013	16,203,000	
9	5.45% Series due September 15, 2013	200,000,000	1,422,659
10			232,000 D
11	4.95% Series due August 15, 2014	200,000,000	1,442,365
12			728,000 D
13	8.734% Series due October 1, 2014	28,218,000	
14	8.294% Series due October 1, 2015	46,946,000	
15	8.635% Series due October 1, 2016	18,750,000	
16	8.470% Series due October 1, 2017	19,609,000	
17	5.65% Series due July 15, 2018	500,000,000	3,067,221
18			905,000 D
19	5.50% Series due January 15, 2019	350,000,000	2,515,793
20			2,292,500 D
21	3.85% Series due June 15, 2021	400,000,000	3,006,612
22			744,000 D
23	7.70% Series due November 15, 2031	300,000,000	2,874,150
24			864,000 D
25	5.90% Series due August 15, 2034	200,000,000	1,892,365
26			722,000 D
27	5.25% Series due June 15, 2035	300,000,000	2,912,021
28			1,080,000 D
29	6.10% Series due August 1, 2036	350,000,000	2,907,881
30			1,141,000 D
31	5.75% Series due April 1, 2037	600,000,000	589,216
32			24,000 D
33	TOTAL	6,858,290,000	77,925,354

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
04/15/1992	10/01/2011	04/15/1992	10/01/2011		24,652	4
11/21/2001	11/15/2011	11/21/2001	11/15/2011		30,187,500	5
						6
04/15/1992	10/01/2012	04/15/1992	10/01/2012	1,867,000	268,315	7
04/15/1992	10/01/2013	04/15/1992	10/01/2013	2,949,000	345,062	8
09/08/2003	09/15/2013	09/08/2003	09/15/2013	200,000,000	10,900,000	9
						10
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	11
						12
04/15/1992	10/01/2014	04/15/1992	10/01/2014	7,259,000	767,762	13
04/15/1992	10/01/2015	04/15/1992	10/01/2015	14,882,000	1,423,168	14
04/15/1992	10/01/2016	04/15/1992	10/01/2016	7,202,000	694,168	15
04/15/1992	10/01/2017	04/15/1992	10/01/2017	8,526,000	789,425	16
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	17
						18
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	19
						20
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	9,753,333	21
						22
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	23
						24
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	25
						26
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	27
						28
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	29
						30
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	31
						32
				6,171,055,000	364,553,118	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	6,134,687
6			6,175,000 D
7	9.15% Series C Medium-Term Notes due Aug. 9, 2011	8,000,000	75,327
8	8.95% Series C Medium-Term Notes due Sept. 1, 2011	25,000,000	175,398
9	8.95% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	132,118
10	8.92% Series C Medium-Term Notes due Sept. 1, 2011	20,000,000	188,318
11	8.29% Series C Medium-Term Notes due Dec. 30, 2011	3,000,000	23,040
12	8.26% Series C Medium-Term Notes due Jan. 10, 2012	1,000,000	7,649
13	8.28% Series C Medium-Term Notes due Jan. 10, 2012	2,000,000	13,297
14	8.25% Series C Medium-Term Notes due Feb. 1, 2012	3,000,000	22,946
15	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
16	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
17	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
18	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
19	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
20	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
21	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
22	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
23	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
24	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
25	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
26	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
27	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
28	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
29			-81,560 P
30	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
31	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
32	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
33	TOTAL	6,858,290,000	77,925,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	37,500,000	1
						2
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	3
						4
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	5
						6
08/09/1991	08/09/2011	08/09/1991	08/09/2011		443,267	7
08/16/1991	09/01/2011	08/16/1991	09/01/2011		1,491,667	8
08/16/1991	09/01/2011	08/16/1991	09/01/2011		1,193,333	9
08/16/1991	09/01/2011	08/16/1991	09/01/2011		1,189,333	10
12/31/1991	12/30/2011	12/31/1991	12/30/2011		248,009	11
01/09/1992	01/10/2012	01/09/1992	01/10/2012	1,000,000	82,600	12
01/10/1992	01/10/2012	01/10/1992	01/10/2012	2,000,000	165,600	13
01/15/1992	02/01/2012	01/15/1992	02/01/2012	3,000,000	247,500	14
01/20/1993	01/22/2013	01/20/1993	01/22/2013	10,000,000	813,000	15
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	16
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	17
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	18
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	19
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	20
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	21
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	22
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	23
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	24
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	25
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	26
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	27
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	28
						29
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	30
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	31
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	32
				6,171,055,000	364,553,118	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
2	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
3	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
4	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
5	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
6	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
7	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
8	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
9	Subtotal - First Mortgage Bonds	6,119,920,000	63,070,314
10			
11	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
12			
13	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
14	5-5/8% Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1993	8,300,000	228,980
15			197,125 D
16	5.65% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993A	46,500,000	1,624,793
17	5-5/8% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993B	16,400,000	625,551
18			389,500 D
19	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
20	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
21	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
22	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
23	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
24	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
25	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
26			105,000 D
27	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
28	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
29	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
30	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
31	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	400,470,000	10,560,809
32			
33	TOTAL	6,858,290,000	77,925,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	1
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	2
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	3
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	4
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	5
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	6
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	7
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	8
				5,432,685,000	352,044,744	9
						10
						11
						12
11/17/1994	05/01/2013	11/17/1994	05/01/2013	40,655,000	354,725	13
11/15/1993	11/01/2021	11/15/1993	11/01/2021	8,300,000	476,835	14
						15
11/15/1993	11/01/2023	11/15/1993	11/01/2023	46,500,000	2,683,050	16
11/15/1993	11/01/2023	11/15/1993	11/01/2023	16,400,000	942,180	17
						18
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	154,373	19
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	67,157	20
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	1,001,333	21
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	74,851	22
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	138,337	23
01/01/1988	01/01/2014	01/01/1988	01/01/2014	17,000,000	680,352	24
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	600,357	25
						26
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	458,698	27
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	359,450	28
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	224,251	29
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	954,199	30
				400,470,000	9,170,148	31
						32
				6,171,055,000	364,553,118	33

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Pollution Control Obligations - Unsecured		
2			
3	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
4	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
5	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
6	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
7	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A	70,000,000	660,750
8	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
9	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A	50,000,000	422,443
10	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
11	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
12	Environ. Imprvmnt Rev Bonds, Sweetwater County, WY, Series 1995	24,400,000	225,000
13	6.150% Environ. Imprvmnt Rev Bonds, Emery County, UT, Series 1996	12,675,000	556,549
14			178,464 D
15			
16	Subtotal - Pollution Control Obligations - Unsecured	337,900,000	4,294,231
17			
18			
19	TOTAL ACCOUNT 221	6,858,290,000	77,925,354
20			
21	Reacquired Bonds: (Account 222)		
22			
23	Advances from Associated Companies: (Account 223)		
24			
25	Other Long-Term Debt: (Account 224)		
26			
27	TOTAL ACCOUNT 224		
28			
29			
30	Long-Term Debt Authorized but Unissued		
31			
32			
33	TOTAL	6,858,290,000	77,925,354

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	87,046	3
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	59,766	4
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	205,414	5
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	78,097	6
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	499,454	7
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	406,008	8
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	409,250	9
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	337,663	10
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	300,352	11
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	175,663	12
09/24/1996	09/01/2030	09/24/1996	09/01/2030	12,675,000	779,513	13
						14
						15
				337,900,000	3,338,226	16
						17
						18
				6,171,055,000	364,553,118	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				6,171,055,000	364,553,118	33

Schedule Page: 256 Line No.: 21 Column: a

In May 2011, PacifiCorp issued $400 million of 3.85% First Mortgage Bonds due June 15, 2021. State commission authorizations for this issuance were as follows:

- Oregon Public Utility Commission ("OPUC") - Docket No. UF-4262, Order No. 10-062, dated February 23, 2010.
- Idaho Public Utilities Commission ("IPUC") - Case No. PAC-E-10-02, Order No. 31018, dated March 5, 2010.

Schedule Page: 256.2 Line No.: 14 Column: b

On March 30, 2012, PacfiCorp redeemed all of the outstanding $8,300,000 principal amount of the bonds.

Schedule Page: 256.2 Line No.: 16 Column: b

On March 30, 2012, PacfiCorp redeemed all of the outstanding $46,500,000 principal amount of the bonds.

Schedule Page: 256.2 Line No.: 17 Column: b

On March 30, 2012, PacfiCorp redeemed all of the outstanding $16,400,000 principal amount of the bonds.

Schedule Page: 256.3 Line No.: 13 Column: b

On March 30, 2012, PacfiCorp redeemed all of the outstanding $12,675,000 principal amount of the bonds.

Schedule Page: 256.3 Line No.: 19 Column: h

Refer to page 108, Important Changes During the Quarter/Year, Item 6, and Notes to Financial Statements of this Form No. 1 for a discussion of PacifiCorp's long-term debt.

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

In December 2010, PacifiCorp filed a shelf registration statement with the United States Securities and Exchange Commission on Form S-3 expected to provide for future first mortgage bond issuances through November 2013.

For authorization for the issuance of long-term debt ($2.0 billion authorized; $1.6 billion available as of December 31, 2011), refer to page 108, Important Changes During the Quarter/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, 2011) by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat,Colorado.

Authorization to borrow the proceeds of new pollution control revenue bonds issued (total of $150,000,000 authorized and available as of December 31, 2011) 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:

- OPUC - Docket No. UF-4250, Order No. 08-382, dated July 29, 2008.
- IPUC - 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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	554,806,039
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	156,713,696
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,499,707,311
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	692,241,881
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	2,061,727,807
26	State Tax Deductions	-108,877
27	Federal Tax Net Income	-542,851,519
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	-189,998,032
31	Provision to Return Adjustment	120,924,543
32	Tax Reserve Changes	763,951
33	Renewable Electricity Production Tax Credits	-71,867,651
34	Mining Rescue Training Credits	-69,284
35	Research & Experimentation Credits	-74,997
36	Hiring Retention Tax Credit	-36,000
37		
38	Federal Income Tax Accrual	-140,357,470
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
Income Tax Interest	179
Sec. 481a Adjustment - Repair Deduction	4,856,357
CIAC	38,665,618
Reimbursements	9,255,805
Avoided Costs	49,883,225
Deferred Excess Net Power Costs - WA Hydro	1,853,327
OR _RCAC Sep-Dec 07 Deferred	638,771
NW Power Act-WA	253,222
Regulatory Liability - Tax Revenue Adjustment - UT	12,462
Regulatory Liability - Tax Revenue Adjustment - WY	29,424
Regulatory Liability - WA Low Energy Program	260,603
Regulatory Liability - OR Balance Consol	387,526
Regulatory Liability - Blue Sky Program OR	1,153,478
Regulatory Liability - Blue Sky Program WA	61,438
Regulatory Liability - Blue Sky Program CA	38,414
Regulatory Liability - Blue Sky Program UT	827,581
Regulatory Liability - Blue Sky Program ID	14,058
Regulatory Liability - Blue Sky Program WY	87,849
Regulaotry Liability - OR 2010 Protocol Def	2,431,626
Regulatory Liability - Sale of Renewable Energy Credits	41,298,890
Regulatory Liability - OR Injuries & Damages Reserve	186,354
Regulatory Liability - OR Property Insurance Reserve	2,971,700
Regulatory Liability - ID Property Insurance Reserve	88,212
Regulatory Liability - WY Property Insurance Reserve	271,761
Regulatory Liability - Powerdale Decommissioning Costs Giveback - UT	540,834
Bear River Settlement Agreement	343,062
Unearned Joint Use Pole Contact Revenue	301,560
MCI FOG Wire Lease	360
Total	$156,713,696

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

Particulars (Details)	Amounts
Fed/State Tax Expense	205,138,412
Fed/State Tax Expense-Interest	(347,404)
Capitalized labor and benefits costs for Power tax input - Permanent	180,232
Meals & Entertainment	1,150,625
Penalties	163,608
Lobbying expenses	2,247,231
MEHC Insurance Services - Premium	1,536,178
Mining Rescue Training Credit Addback - PacifiCorp	69,284
Non-deductible post-retirement costs	6,498,152
Capitalized labor and benefits costs for Power tax input - Temporary	9,141,845
Book Depreciation	617,695,737
ARO - reclass to regulatory assets/liability & ARO liability	243,355
Book Cost Depletion - Addback	1,637,291
Regulatory Asset - FAS 158 Pension Liab Adj.	28,692,000
Regulatory Asset - FAS 158 Post Ret. Liab.	17,426,000
Environmental Costs - WA	100,170
Cholla Plant Transaction Costs-APS Amortization	1,122,425
WA Disallowed Colstrip #3-Write-off	52,188
Regulatory Asset - Lake Side Liquidation	27,919
Goodnoe Hills Liquidation Damages - WY	21,250
RTO Grid West Notes Receivable - OR	382,521
RTO Grid West Notes Receivable - ID	27,162
Regulatory Asset - Pension MMT -UT	283,176
Regulatory Asset - Post -Ret MMT -OR	193,035

Regulatory Asset - Post -Ret MMT -WY	308,642
Regulatory Asset - Post - Ret MMT -UT	278,648
Regulatory Asset - Post - Ret MMT -CA	15,467
Regulatory Asset-Deferred OR Independent Evaluator Fees	731,407
Powerdale Decommissioning Reg Asset - ID	92,045
Powerdale Decommissioning Reg Asset - OR	493,016
Powerdale Decommissioning Reg Asset - WA	212,947
CA - January 2010 Storm Costs	1,164,006
Powerdale Decommissioning Reg Asset - WY	34,392
ID - Deferred Overburden Costs	73,045
WY - Deferred Overburden Costs	177,893
WY - Deferred Advertising Costs	52,198
Reg Asset - Utah MPA	15,724,521
Regulatory Asset - CA Solar Feed-in Tariff	246,352
Deferred Excess Net Power Costs - OR	3,587,516
Deferral of Renewable Energy Credit - UT	16,637
Deferral of Renewable Energy Credit - WY	517,165
OR - MEHC Transition Service Costs	2,056,752
WA - Chehalis Plant Revenue Requirement	3,000,000
Reg Asset MEHC Transition Service Costs - CA	178,218
Deferred Coal Costs - Naughton Contract Settlement	1,376,154
Idaho Customer Balancing Account	1,390,489
Weatherization	9,654,869
Trojan Decommissioning Costs - Regulatory	13,316
Regulatory asset - Net Derivatives	224,102,593
Coal Pile Inventory Adjustment	4,081,423
Prepaid Taxes - Property Taxes	4,582,312
RTO Grid West Note Receivable - w/o - WA	23,470
TGS Buyout	15,474
Joseph Settlement	137,381
Hermiston Swap	171,693
Western Coal Carrier Postretirement Benefit Accrual	1,092,000
Derivatives - Current	105,117,145
Post Merger Loss-Reacquisition Debt - Addback	1,769,843
Reg Liability - Other - Balance Reclass	1,162,501
Reg Liability - Def NPC Balance Reclass	595,234
CA-California Alternative Rate for Energy Program (CARE)	491,616
Bonus Liability - Electric - Cash Basis (2.5 months)	202,705
Vacation Accrual - Cash Basis (2.5 months)	880,541
Pension / Retirement Accrual - Cash Basis	19,746
FAS 143 ARO Liability	17,988,698
Bad Debts Allowance - Cash Basis	4,402,986
Current Liability - Frozen MTM	23,495,569
Noncurrent Liability - Frozen MTM	166,506,240
Deferred Coal Cost - Arch	63,030
Rogue River - Habitat Enhancement Liability	5,622
Lewis River Settlement Agreement	150,145
Other Environmental Liabilities	3,215,255
N. Umpqua Settlement Agreement	1,290,244
Umpqua Settlement Agreement	119,572
Accrued Royalties	213,332
Reverse Accrued Final Reclamation	280,840
Unrealized Gain/Loss from Trading Securities	201,976
FAS 112 Book Reserve	2,250,038
Total	$1,499,707,311

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

Particulars (Details)	Amounts
Utah Deferred Comp / COLI	(2,468,699)

Medicare Subsidy	(7,078,985)
AFUDC - Debt	(23,812,185)
AFUDC - Equity	(44,939,836)
Basis Intangible Difference	(2,401,039)
Book Gain/Loss on Land Sales	(665,002)
Reg Asset Utah ECAM	(67,787,260)
Regulatory Asset - Frozen MTM	(186,949,133)
Deferral of Renewable Energy Credit - WA	(681,343)
Regulatory Asset balance reclass	(387,526)
Trojan Decommissioning Costs - WA	(22,981)
Trojan Decommissioning Costs - OR	(5,663)
Trapper Mining Stock Basis	(676,356)
NonCurrent Asset - Frozen MTM	(478,212)
Current Asset - Frozen MTM	(2,574,464)
ARO Regulatory Liabilities	(17,828)
Regulatory liability BPA balancing accounts	(477,089)
Reg Liability - Sale of Renewable Energy Credit - OR	(1,378,118)
Regulatory Liab - OR Energy Conservation Charge	(14,795)
Regulatory Liability - Deferred Benefit Arch Settlement	(44,269)
Regulatory Liability - CA Gain on Sale of Asset	(3,755)
Regulatory Liability - Sale of Renewable Energy Credits - WY	(3,594,057)
Regulatory Liability - UT Property Insurance Reserve	(683,323)
SMUD Revenue Imputation - UT regulatory liability	(2,292,156)
Derivatives - noncurrent	(328,103,560)
Willow Wind Account Receivable	(97,667)
Def Regulatory Asset-Foote Creek Contract	(137,640)
Tenant Lease Allow - PSU Call Center	(48,157)
Duke/Hermiston Contract Renegotiation	(408,871)
Deferred Revenue - Citibank	(23,000)
Redding Contract - Prepaid	(549,996)
Equity Earnings in Subsidiaries	(9,511,469)
Intercompany Adjustments	(3,927,447)
Total	$(692,241,881)

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

Particulars (Details)	Amounts
Book Depreciation Allocated to Medicare and M&E	(267,291)
Tax Percentage Depletion - Blundell Steam Field (Prior IGC)	(448,549)
PPL Pre - 1943 Preferred Stock Div - Deduction	(381,063)
MEHC Insurance Services - Receivable	(8,945,767)
Dividend Received Deduction - Deferred Compensation	(139,230)
PMI Overriding Coal Royalty % Depletion - PacifiCorp	(11,748)
Repair Deduction	(151,344,053)
Tax Depreciation	(1,634,165,916)
Capitalized Depreciation	(5,120,793)
Mine Safety Sec 179E Election ~PPW	(33,504)
Gain / (Loss) on Prop. Disposition	(23,913,401)
Coal Mine Development	(187,747)
Coal Mine Extension	(2,958,831)
Removal Costs	(71,456,910)
Cholla SHL-NOPA (Lease Amortization)	(97,718)
ARO - reclass to ARO liabilities	(3,287,083)
Tax Percentage Depletion - Deduction	(399,154)
Tax Depletion	(162,730)
ARO Regulatory Assets	(14,683,787)
Environmental Clean-up Accrual	(4,556,435)
Cholla Plant Transaction Costs - APS Amortization - ID	(32,973)
Cholla Plant Transaction Costs - APS Amortization - OR	(53,813)
Cholla Plant Transaction Costs - APS Amortization - WA	(97,006)

CA Deferred Intervenor Funding	(32,885)
Deferred Intervenor Funding Grants	(308,563)
Contra Pension Regulatory Asset MMT & CTG _OR	(1,014,634)
Contra Pension Regulatory Asset MMT & CTG _WY	(1,663,914)
Contra Pension Regulatory Asset CTG - UT	(5,951,295)
Contra Pension Regulatory Asset MMT & CTG _CA	(81,988)
Contra Pension Regulatory Asset CTG - WA	(1,017,963)
Unrecovered Plant - Powerdale	(279,021)
Powerdale Decommissioning Reg Asset - CA	(33,069)
Reg Asset - OR Solar Feed-In Tariff	(1,043,825)
Deferred Excess Net Power Costs-CA	(197,452)
Deferred Excess Net Power Costs - WY 09 and After	(19,602,585)
Deferred UT Independent Evaluation Fee	(92,241)
Deferred Excess Net Power Costs - ID 09	(10,304,274)
OR SB 408 Recovery	(5,812,362)
Deferred Regulatory Expense	(14,904)
Reg Asset - Other - Balance Reclass	(1,162,501)
Reg Asset - Def NPC Balance Reclass	(595,234)
Prepaid Taxes - OR PUC	(274,543)
Prepaid Taxes - UT PUC	(628,106)
Prepaid Taxes - ID PUC	(47,271)
Other Prepaid	(283,083)
LT Prepaid IBEW 57 Pension Contribution	(5,651,545)
Wasach workers comp reserve	(138,194)
Non-ARO Liability - Regulatory Liability	(243,355)
Regulatory Liability - UT Home Energy Lifeline	(142,823)
OR Regulatory Asset/Liability Consolidation	(52)
Oregon Gain on Sale	(33,140)
Deferred Compensation Accrual - Cash Basis	(437,171)
Severance Accrual - Cash Basis	(18,021)
Pension Liability	(49,568,900)
Post-Retirement Liability	(19,355,803)
SERP Liability	(781,448)
Distribution O&M Amortization of Write-off	(2,600,530)
PMI-Fuel Cost Adjustment	(600,889)
M&S Inventory Write-Off	(126,473)
R & E - Sec.174 Deduction	(1,043,765)
Def Regulatory Asset-Transmission Service Deposit	(844,425)
BPA Conservation Rate Credit	(692,100)
Trail Mountain Accrued Liabilities	(559,464)
Misc. Current and Accrued Liability	(1,901,611)
Accrued Insurance Premium Tax	(711,437)
Amortization NOPAs 99-00 RAR	(58,446)
Injuries and Damages Accrual - Cash Basis	(3,031,000)
Total	$(2,061,727,807)

Schedule Page: 261 Line No.: 38 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
Fossil Rock Fuels, LLC
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.
PacifiCorp Environmental Remediation Company
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, LLC
BG Energy Holding LLC
BG Energy LLC
Bishop Hill II Holdings, LLC
CalEnergy Company, Inc
CalEnergy Generation Operating Company
CalEnergy Holdings, Inc
CalEnergy International Services, Inc
CalEnergy International, Inc
CalEnergy Minerals Development LLC
CalEnergy Minerals LLC
CalEnergy Pacific Holdings Corp
CalEnergy UK Inc
Capitol Intermediary Company
Capitol Title Company
CBEC Railway, Inc
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc
CBSHome Relocation Services, Inc
CE Administrative Services, Inc
CE Black Rock Holdings LLC
CE Butte Energy Holdings LLC
CE Butte Energy LLC
CE Electric (NY), Inc
CE Electric, Inc
CE Exploration Company
CE Geothermal, Inc.
CE Indonesia Geothermal, Inc
CE International Investments, Inc
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Power, Inc
CE Red Island Energy Holdings LLC
CE Red Island Energy LLC
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 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 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 Insurance, Inc
HomeServices of Alabama, Inc.
HomeServices of America, Inc
HomeServices of California, Inc
HomeServices of Florida, Inc
HomeServices of Illinois Holdings, LLC
HomeServices of Iowa, Inc
HomeServices of Kentucky Real Estate Academy, LLC
HomeServices of Kentucky, Inc
HomeServices of Nebraska, Inc
HomeServices of the Carolinas, Inc
HomeServices Relocation, LLC
HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
HSR Equity Funding, Inc
Huff Commercial Group, LLC
Huff-Drees Realty, Inc
IMO Company, Inc
Iowa Realty Company, Inc
Iowa Realty Insurance Agency, Inc
Iowa Title Company
J.S. White Associates, Inc
JBRC, Inc
Jim Huff Realty, 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 America Transco, LLC
MEHC Insurance Services Ltd.
MEHC Investment, Inc
MEHC Texas Transco, LLC
MHC Investment Company
MHC, Inc
Mid-America Referral Network, Inc.
MidAmerican AC Holding, LLC
MidAmerican Energy Company
MidAmerican Energy Holdings Company
MidAmerican Energy Machining Services LLC
MidAmerican Funding, LLC
MidAmerican Geothermal, LLC
MidAmerican Hydro, LLC
MidAmerican Nuclear Energy Company, LLC
MidAmerican Nuclear Energy Holdings Co., LLC
MidAmerican Renewables, LLC
MidAmerican Solar, LLC
MidAmerican Transmission, LLC
MidAmerican Wind, LLC
Midland Escrow Services, Inc
Midwest Capital Group, Inc
Midwest Gas Company
Midwest Power Transmission Illinois LLC
Midwest Power Transmission Iowa LLC
MWR Capital, Inc
Nebraska Land Title & Abstract Company
NNGC Acquisition, LLC
Northern Aurora Inc
Northern Natural Gas Company
Pickford Escrow Company, Inc
Pickford Holdings LLC
Pickford Real Estate, Inc
Pickford Services Company, Inc

Plaza Financial Services, LLC
Plaza Mortgage Services, LLC
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
Reece Commercial, Inc.
Referral Company of North Carolina, Inc
RHL Referral Company, LLC
Roberts Brothers, Inc
Roy H. Long Realty Company, Inc
Salton Sea Minerals Corporation
San Diego PCRE, Inc
Semonin Realtors, Inc
Southwest Relocation, LLC
The Escrow Firm
The Referral Company
Title South, LLC
TPZ Holding, LLC
Two Rivers, Inc
United Settlement Services, L.C.

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 from costs borne by utility customers.

Berkshire Hathaway Inc. Sub-Group:
21 SPC, Inc.
21st Communities, Inc.
21st Mortgage Corporation
AAS-Lunken, Inc.
Ace Mailing Service, 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 Services Company, L.P.
Active Organics, Inc.
Adalet/Scott Fetzer Company
AEG Processing Center No. 35, Inc.
AEG Processing Center No. 58, Inc.
Affordable Housing Partners, Inc.
Agile Manufacturing, Inc.
AJF Warehouse Distributors, Inc.
AL/TEX Homes, Inc.
Albecca, Inc.
Alexander Road Insurance Agency, Inc.
Alexander-Otto Company LLC
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 and Stone, Inc
Apeks Apparel, Inc.
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logistics, Inc.
Applied Premium Finance, Inc.
Applied Risk Services of New York, Inc.
Applied Risk Services, Inc.
Applied Underwriters Captive Risk Assurance Company, Inc.

Applied Underwriters, Inc.
Atlanta International Insurance Company
AU Captive Risk Assurance Co.
AU Captive Risk Assurance Co., Inc.
AU Holding Company, Inc.
Bayport Systems, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
Berkadia Commercial Mortgage Inc.
Berkshire Hathaway Assurance Corporation
Berkshire Hathaway Credit Corporation
Berkshire Hathaway Finance Corporation
Berkshire Hathaway Homestate Insurance Company
Berkshire Hathaway Inc.
Berkshire Hathaway Life Insurance Company of Nebr.
BH Affordable Housing, Inc.
BH Columbia Inc.
BH Finance, Inc.
BH Shoe Holdings, Inc.
BH, LLC
BHG Structured Settlements, Inc.
BHR Inc.
BHSF, Inc.
Blue Chip Stamps
Blue Chip Stamps, Inc
BN Leasing Corporation
BNJ NetJets, Inc.
BNSF Communications, Inc.
BNSF Logistics International, Inc.
BNSF Railway Company
BNSF Railway International Services, Inc.
BNSF Spectrum, Inc.
Boat America Corporation
Boat U.S, Inc.
Boot Royalty Company
Borsheim Jewelry Company, Inc
BR Agency, Inc.
Brick Acquisition Company
Bricker-Mincolla Uniforms
Brilliant National Services, Inc.
Brooks Sports, Inc.
Brookwood Insurance Company
Burlington Northern Railroad Holdings, Inc.
Burlington Northern Santa Fe British Columbia, Ltd.
Burlington Northern Santa Fe Insurance Company, Ltd.
Burlington Northern Santa Fe Manitoba, Inc.
Burlington Northern Santa Fe, LLC
Business Wire, Inc.
C & R Insurance Services, Inc.
C & R Legal Insurance Agency, LLC
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld/Scott Fetzer Company
Capitol Avenue Real Estate Company
Carefree/Scott Fetzer Company
Cavalier Homes, Inc.
Central Nebraska Publications, 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
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 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
Consolidated Health Plans Inc.
Continental Divide Insurance Company
Continental Indemnity Company
Corbond Corporation
Cort Business Services Corporation
Coverage Dynamics Group, Inc.
CPI Engineering Services, 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 Inc.
CTB International Corp
CTB IW INC
CTB MN Investments
Cumberland Asset Management, Inc.
Cypress Insurance Company
Dairy Queen Corporate Stores, Inc.
Dairy Queen Of Georgia, Inc.
Denver Brick Company
Dexter Shoe Company
Diedrich Technologies, Inc.
Diversified Mailing, Inc.
Douglas Building, LLC
DQ Funding Corporation
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
Eco Color Company
Ecodyne Corporation
Edmonds Material and Equipment Co.
Elm Street Corporation
Empire Distributors of North Carolina, Inc.
Empire Distributors, Inc.
Executive Jet Europe, Inc.
Executive Jet Management, Inc.
Expertos en Administracion, S.A. de C.V.
Exsif Worldwide, Inc.
Fairfield Insurance Company
Faraday Capital Limited
Farriors, Inc.
Finial Holdings, Inc.
Finial Reinsurance Company
First Berkshire Hathaway Life Insurance Company
FlightSafety Capital Corp.
FlightSafety Development Corp.
FlightSafety International Inc.
FlightSafety New York, Inc.
FlightSafety Properties, Inc.
FlightSafety Services Corporation
Floors, Inc.
Fontaine Fifth Wheel Company
Fontaine Modification Company
Fontaine Specialized, Inc.
Fontaine Spray Suppression Company
Fontaine Trailer Company

Fontaine Truck Equipment Company
Footwear Investment Company
Forest River Financial Services, Inc.
Forest River Housing, Inc.
Forest River, Inc.
France/Scott Fetzer Company
Freedom Warehouse Corp.
FreightWise, Inc.
Fruit of The Loom Caribbean, Inc.
Fruit of the Loom Direct, Inc.
Fruit of the Loom Trading Company
Fruit of the Loom, Inc.
Fruit of the Loom, Inc. (Sub)
FTL Regional Sales Co., Inc.
FTL Sales Company, Inc.
Fulton Manufacturing Company
Garan Central America Corp.
Garan Incorporated
Garan Manufacturing Corp.
Garan Services Corp
Gateway Underwriters Agency, Inc.
GEICO Advantage Insurance Company
GEICO Casualty Co.
GEICO Choice Insurance Company
GEICO Corporation
GEICO General Insurance Co.
GEICO Indemnity Co.
GEICO Insurance Agency
GEICO Products, Inc.
GEICO Secure Insurance Company
Gen Re Intermediaries Corporation
Gen Re Long Ridge LLC
General Re Corporation
General Re Financial Products Corporation
General Re New England Asset Management
General Reinsurance Corporation
General Star Indemnity Company
General Star Management Company
General Star National Insurance Company
Genesis Indemnity Insurance Company
Genesis Insurance Company
Genesis Management and Insurance Services Corporation
Getz Bros. & Co. Zug, Inc.
Giles Industries, Inc.
Golden Skillet International, Inc.
Government Employees Financial Corp.
Government Employees Insurance Co.
Grand Island Independent Real Estate, LLC
Grand Island Publishing Company, Inc.
GRD Holdings Corporation
Great Plains Uniforms
Griffey Uniforms
H. H. Brown Shoe Company, Inc.
H. H. Brown Shoe Technologies, Inc.
H.J. Justin & Sons, Inc.
Halex/Scott Fetzer Company
Hardy Frames, Inc.
Harris Uniforms
Harrison Uniforms
HDS Redevelopment Corporation
HeatPipe Technology, Inc.
Helzberg's Diamond Shops, Inc.
Hemingford Building, LLC
Henley Holdings, LLC
HG-Power Plant. Inc.
Hohmann & Barnard, Inc.
Homefirst Agency, Inc.
Homemakers Plaza, Inc.
Horizon Wine & Spirits - Chattanooga, Inc.
Horizon Wine & Spirits - Nashville, Inc.
Innovative Building Products, Inc
International America Group Inc.

International American Management Company
International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
Ironwood Plastics Inc
Isabella Shoe Corporation
J.L. Mining Company
J.S Justin, 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.
Justin Industries, Inc.
Kahn Ventures, Inc.
Kale Uniforms
Kansas Bankers Surety Company
Karmelkorn Shoppes, Inc.
Kay Uniforms
Kearney Hub Publishing Company, Inc.
L.A. Terminals, Inc.
Laurier Indemnity Company
LEE Distributing Service, Inc.
Leesburg Yarn Mills, Inc.
Lexington Publishing Company, Inc.
Lockwood Street Urban Renewal Corporation
Los Angeles Junction Railway Company
Lubricant Investments, Inc.
Lubrizol Advanced Materials China, Inc.
Lubrizol Advanced Materials FCC, Inc.
Lubrizol Advanced Materials Gibraltar, Inc.
Lubrizol Advanced Materials Holding Corporation
Lubrizol Advanced Materials International, Inc.
Lubrizol Advanced Materials, Inc.
Lubrizol Enterprises, Inc.
Lubrizol Holding, Inc
Lubrizol Inter-Americas Corporation
Lubrizol International Management Corporation
Lubrizol Overseas Trading Corporation
LZ Holding Corporation
M & C Products, Inc.
Macro Retailing, Inc.
Mail Tech, Ltd.
Mapletree Transportation, Inc.
Marathon Suspension Systems, Inc.
Marmon Construction Services, Inc.
Marmon Distribution Services, Inc.
Marmon Flow Products, Inc.
Marmon Holdings, Inc.
Marmon Industrial Companies, Inc.
Marmon Retail Services, Inc.
Marmon Water, Inc.
Marmon Wire & Cable, Inc.
Marmon-Herrington Company
Marquis Jet Holdings, Inc.
Marquis Jet Partners, 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.
Merquinsa North America, Inc.
Metro Uniforms
MH Transport, Inc.
Midlands Newspapers, Inc.
Midwest Northwest Properties, Inc.
Miller-Sage, Inc.
MiTek Framings, Inc.
MiTek Holdings, Inc.
MiTek Industries, Inc.
MiTek, Inc.
MMX Corporation
Mobile Disaster Structures, Inc
Morgantown-National Supply, Inc.
Mount Vernon Fire Insurance Company
Mouser Electronics, Inc.
MPP Pipeline Corporation
MS Property Company
National Fire & Marine Insurance Company
National Indemnity Company
National Indemnity Company of Mid-America
National Indemnity Company of the South
National Liability & Fire Insurance Company
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 Platte Publishing Company, Inc.
Northern States Agency, Inc.
Northland/Scott Fetzer Company
Noveon Hilton Davis, Inc.
Oak River Insurance Company
Ohio Merger Sub, Inc.
Omaha World-Herald Company
Orange Julius Of America
Pan-Am Shoe Co., Inc.
Penn Coal Land, Inc.
Penn Pocahontas Coal Co.
Perfection Hy-Test Company
Pima Uniforms
Pine Canyon Land Company
PJR Management, Inc.
Plaza Financial Services Co.
Plaza Resources Co.
Ponce Fashions, Inc.
Precision Brand Products, Inc.
Precision Millwork Settings LLC
Precision Steel Warehouse - Charlotte S/C
Precision Steel Warehouse, Inc.

Princeton Advertising & Marketing Group, Inc.
Princeton Insurance Company
Princeton Risk Protection, Inc
Priority One Financial Services, Inc.
Pro Installations, Inc.
Procrane Holdings, Inc.
Professional Datasolutions, Inc.
Promesa Health, Inc.
Queen Carpet Corporation
R.C. Willey Home Furnishings
Rabun Apparel, Inc.
Railserve, Inc.
Railsplitter Holdings Corporation
RCP Investment, Inc.
Redwood Fire and Casualty Insurance Company
RENTCO Trailer Corporation
Resolute Management Inc.
Richline Group, Inc
Ringwalt & Liesche Co.
Riverview Land, LLC
Roberts Men's Shop
Running with Heels, Inc.
Rush Air Inc
Russell Athletic Corporation
Salado Sales, Inc.
Santa Fe Pacific Insurance Company
Santa Fe Pacific Pipeline Holdings, Inc.
Santa Fe Pacific Pipelines, Inc.
Santa Fe Pacific Railroad Company
Santa Fe Receivables Corporation
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
Scottsbluff Publishing Company, Inc.
Seaworthy Insurance Company
See's Candies, Inc
Sees Candy Shops, Incorporated
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.
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
Sol Frank Uniforms Inc.
Somerset Services, Inc
Southern Energy Homes, Inc.
Southwest Iowa Newspapers, Inc.
Spectra Contract Flooring Puerto Rico, Inc.
Stahl/Scott Fetzer Company
Star Furniture Company
Star Lake Railroad Company
Stonewall Insurance Company
Strategic Staff Management, Inc.
Strick Mexicana, S.A. de C.V.
Suburban Newspapers, Inc.
The Ben Bridge Corporation
The BN and SF Railway de Mexico, S.A. de C.V.
The Buffalo News, Inc.
The BVD Licensing Corporation
The Eagle Company

The Fechheimer Brothers Co.
The Indecor Group, Inc.
The Lubrizol Corporation
The Medical Protective Company
The Pampered Chef, Ltd.
The Scott Fetzer Company
The Zia Company
Tiger-Sunbelt Industries, Inc.
TMI Custom Air Systems, Inc.
Tony Lama Company
Top Five Club, Inc.
Total Quality Apparel Resources
TPC European Holdings, LTD.
TPC N.A.S.A., LLC
TPC North America, Ltd.
Transco, Inc.
TRH Holding Corp.
Triangle Suspension Systems, Inc.
TSE Brakes, Inc.
TTI, Inc.
TXFM, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Co.
Undergarment Fashions, Inc.
Unified Supply Chain, Inc.
Uni-Form Components Company
Uniforms of Texas
Union Sales, Inc.
Union Tank Car Company
Union Underwear Co., Inc
Unione Italiana Reinsurance Company of America, Inc.
United Consumer Financial Services Company
United Direct Finance, Inc.
United States Aviation Underwriters, Inc.
United States Liability Insurance Company
United Steel Products Company
Universal Uniforms
Vanderbilt ABS Corp.
Vanderbilt Mortgage and Finance, Inc.
Vanderbilt Property & Casualty Insurance Co., Ltd.
Vanderbilt SPC, Inc.
Vanity Fair, Inc.
Veritas Insurance Group, Inc.
Vessel Assist Insurance Services, Inc.
VFI-Mexico, Inc.
Vision Retailing, Inc.
Wayne/Scott Fetzer Company
Waynesburg Shirt Company Inc.
Webb Wheel Products, Inc.
Wesco Financial Corporation
Wesco Holdings Midwest, Inc.
Wesco-Financial Insurance Company
West Virginia Uniforms
Western Fruit Express Company
Western Iowa Newspapers, Inc.
Western Nebraska Newspapers, Inc.
Western/Scott Fetzer Company
Whittaker, Clark & Daniels, Inc.
Winona Bridge Railroad Company
WMC Corp.
World Book Encyclopedia, Inc.
World Book, Inc.
World Book/Scott Fetzer Company
World Broadcasting, Inc.
World Enterprises, Inc.
World Interactive Group, Inc.
World Investments, Inc.
World Marketing, Inc.
World Media Company
World Real Estate Management, LLC
World Technologies, Inc.
Worldbook.com, Inc.

Worldwide Containers, Inc.
X-L-Co., Inc.
XLI, Inc.
XTR, Inc.
XTRA Chassis, Inc.
XTRA Companies, Inc.
XTRA Corporation
XTRA Finance Corporation
XTRA Intermodal, Inc.
XTRA International Pacific, Ltd.
XTRA International, Ltd.
XTRA Mexicana, S.A. de C.V.
York Publishing Company, Inc.
Zuckerbergs Uniforms

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR: Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	13,589,884	352,792,763	-140,504,783	-425,509,841	-5,057,917
3	FICA	469,549	-3,514	36,337,223	36,391,671	
4	Unemployment	4,320		339,186	338,122	-1
5	Excise Tax - Coal	162,786		3,258,065	3,239,588	
6	Subtotal	14,226,539	352,789,249	-100,570,309	-385,540,460	-5,057,918
7						
8	State:					
9						
10	Arizona:					
11	Property	1,181,569		2,609,199	2,486,169	
12	Income		18,570	20,312		-9,871
13	Subtotal	1,181,569	18,570	2,629,511	2,486,169	-9,871
14						
15	California:					
16	Property			2,202,837	2,202,837	
17	Unemployment	769		34,630	33,310	
18	Franchise-Income		110,746	186,555	375,870	-9,778
19	Use	3,282		330,364	293,698	
20	Local Franchise	973,724		1,278,585	1,068,351	
21	Subtotal	977,775	110,746	4,032,971	3,974,066	-9,778
22						
23	Colorado:					
24	Property	1,800,000		1,829,101	1,869,101	
25	Income			-389		-1,933
26	Subtotal	1,800,000		1,828,712	1,869,101	-1,933
27						
28	Idaho:					
29	Property	2,639,428		5,222,882	4,867,535	
30	Income		-1,323,020	-71,290	1,490,536	-24,760
31	KWh	13,676		36,359	49,285	
32	Unemployment	1,915		58,468	59,243	
33	Use	13,978		143,750	141,576	
34	Subtotal	2,668,997	-1,323,020	5,390,169	6,608,175	-24,760
35						
36	Montana:					
37	Property	1,632,561		2,835,131	3,051,599	
38	Corporate License-Income		-86,000	-59,547	26,932	-2,383
39	Unemployment			1,252	1,252	
40	Energy License	63,866		200,228	206,530	
41	TOTAL	48,501,673	355,776,477	59,788,345	-215,967,798	-5,730,851

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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 (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
17,233,393	66,373,297	-138,818,714			-1,686,069	2
430,018	11,403				36,337,223	3
5,385					339,186	4
181,263					3,258,065	5
17,850,059	66,384,700	-138,818,714			38,248,405	6
						7
						8
						9
						10
1,304,599		2,609,199				11
	-11,613	25,874			-5,562	12
1,304,599	-11,613	2,635,073			-5,562	13
						14
						15
		2,042,871			159,966	16
2,089					34,630	17
	290,283	192,065			-5,510	18
39,948					330,364	19
1,183,958		1,278,585				20
1,225,995	290,283	3,513,521			519,450	21
						22
						23
1,760,000		1,725,158			103,943	24
	-1,544	700			-1,089	25
1,760,000	-1,544	1,725,858			102,854	26
						27
						28
2,994,775		5,078,891			143,991	29
	214,046	-57,338			-13,952	30
750		36,359				31
1,140					58,468	32
16,152					143,750	33
3,012,817	214,046	5,057,912			332,257	34
						35
						36
1,416,093		2,835,131				37
	-1,904	-58,204			-1,343	38
					1,252	39
57,564		200,228				40
52,714,616	78,502,426	5,017,607			54,770,738	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Wholesale Energy	45,506		142,707	147,162	
2	Subtotal	1,741,933	-86,000	3,119,771	3,433,475	-2,383
3						
4	New Mexico:					
5	Property			7,054	7,054	
6	Income			-319	50	-1,836
7	Subtotal			6,735	7,104	-1,836
8						
9	Oregon:					
10	Property		10,743,370	21,629,033	21,863,586	
11	Unemployment	50,434		1,729,458	1,729,165	
12	Wilsonville Payroll	260		1,491	1,217	
13	Excise-Income		677,838	-1,176,852	-1,722,276	-161,257
14	City of Portland-Income		-470	-809	1,556	-4,454
15	Department of Energy		365,145	789,851	849,411	
16	Tri-Met	343,631		932,248	937,327	
17	Lane County			1,878	1,878	
18	Franchise	4,158,926		25,327,096	25,081,450	
19	Subtotal	4,553,251	11,785,883	49,233,394	48,743,314	-165,711
20						
21	Utah:					
22	Property	470,896		56,701,563	56,737,170	
23	Income		-7,518,951	-5,882,127	1,959,272	-154,791
24	Unemployment	2,196		376,629	371,202	
25	Navajo Nation			1,233	1,233	
26	Salt Lake Valley Law Enforc			599	599	
27	Use	541,588		3,607,277	3,714,157	
28	Subtotal	1,014,680	-7,518,951	54,805,174	62,783,633	-154,791
29						
30	Washington:					
31	Property	8,700,000		9,272,990	8,932,990	
32	Unemployment	6,264		98,168	103,395	
33	Business & Occupation	3,380		36,596	36,562	
34	Wholesaling			3,239	2,868	
35	Public Utility	1,060,006		10,525,344	10,485,350	
36	Natural Gas Use Tax	115,817		1,264,075	1,194,500	
37	Use	48,219		1,007,088	433,184	
38	Subtotal	9,933,686		22,207,500	21,188,849	
39						
40	Wyoming:					
41	TOTAL	48,501,673	355,776,477	59,788,345	-215,967,798	-5,730,851

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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 (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
41,051		142,707				1
1,514,708	-1,904	3,119,862			-91	2
						3
						4
		7,054				5
	-1,467	716			-1,035	6
	-1,467	7,770			-1,035	7
						8
						9
	10,977,923	20,936,361			692,672	10
58,472	7,745				1,729,458	11
534					1,491	12
	-28,843	-1,085,985			-90,867	13
	-2,559	1,701			-2,510	14
	424,705	789,851				15
338,552					932,248	16
					1,878	17
4,404,572		25,327,096				18
4,802,130	11,378,971	45,969,024			3,264,370	19
						20
						21
435,289		52,840,320			3,861,243	22
	167,657	-5,794,904			-87,223	23
7,545	-78				376,629	24
		1,233				25
		599				26
434,708					3,607,277	27
877,542	167,579	47,047,248			7,757,926	28
						29
						30
9,040,000		9,070,073			202,917	31
1,037					98,168	32
3,414		36,596				33
371					3,239	34
1,100,000		10,525,344				35
185,392					1,264,075	36
622,123					1,007,088	37
10,952,337		19,632,013			2,575,487	38
						39
						40
52,714,616	78,502,426	5,017,607			54,770,738	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Property	7,189,617		14,452,092	14,415,665	
2	Unemployment	6,316		387,946	385,472	
3	Franchise	247,000		1,662,900	1,642,000	
4	Use	139,909		1,259,796	1,581,508	
5	Annual Report			56,536	56,536	
6	Subtotal	7,582,842		17,819,270	18,081,181	
7						
8	State Other	2,802,462		-1,112,441		-301,870
9						
10	Miscellaneous:					
11	Goshute Possessory			15,551	15,551	
12	Sho-Ban Possessory			182,034	182,034	
13	Navajo Possessory	17,939		36,463	36,170	
14	Ute Possessory			29,031	29,031	
15	Crow Possessory			64,962	64,962	
16	Umatilla Possessory			69,847	69,847	
17	Subtotal	2,820,401		-714,553	397,595	-301,870
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	48,501,673	355,776,477	59,788,345	-215,967,798	-5,730,851

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 (I) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
7,226,044		14,098,055			354,037	1
8,790					387,946	2
267,900		1,662,900				3
-181,803					1,259,796	4
		56,536				5
7,320,931		15,817,491			2,001,779	6
						7
2,075,266	83,375	-1,087,339			-25,102	8
						9
						10
		15,551				11
		182,034				12
18,232		36,463				13
		29,031				14
		64,962				15
		69,847				16
2,093,498	83,375	-689,451			-25,102	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
52,714,616	78,502,426	5,017,607			54,770,738	41

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

($2,327,176) Account 190, Accumulated deferred income taxes (1)
(2,730,741) Adjustment related to equity investees.
($5,057,917)

(1) Represents the tax benefit of interest reclassified to Account 190.

Footnote amended in accordance with FERC Order No. AC11-132.

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

($1,538,756) Account 409.2, Income taxes - Federal (1)
(147,313) Account 419, Interest and dividend income (2)
($1,686,069)

(1) Applicable to other income and deductions.
(2) Interest on uncertain tax positions that are effectively settled.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Account 151, Fuel stock

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

Adjustment related to equity investees.

Footnote amended in accordance with FERC Order No. AC11-132.

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

Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

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

$146,195 Account 408.2, Taxes other than income taxes
1,512 Account 589, Rents
12,259 Account 107, Construction work in progress
$159,966

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

See footnote at page 262, line 12, column f.

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

Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

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

Charged to same account as related goods.

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

$ 733 Account 408.2, Taxes other than income taxes
 103,210 Account 107, Construction work in progress
$103,943

Schedule Page: 262 Line No.: 25 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262 Line No.: 25 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 29 Column: l
$ 1,380 Account 408.2, Taxes other than income taxes
 142,611 Account 107, Construction work in progress
$143,991

Schedule Page: 262 Line No.: 30 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262 Line No.: 30 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 32 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262 Line No.: 33 Column: l
Charged to same account as related goods.

Schedule Page: 262 Line No.: 38 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262 Line No.: 38 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

Schedule Page: 262 Line No.: 39 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 6 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262.1 Line No.: 6 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

Schedule Page: 262.1 Line No.: 10 Column: l
$ 13,348 Account 408.2, Taxes other than income taxes
 133,245 Account 589, Rents
 546,079 Account 107, Construction work in progress
$692,672

Schedule Page: 262.1 Line No.: 11 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 12 Column: l
Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.1 Line No.: 13 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262.1 Line No.: 13 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

Schedule Page: 262.1 Line No.: 14 Column: f
See footnote at page 262, line 12, column f.

Schedule Page: 262.1 Line No.: 14 Column: l
Account 409.2, Income taxes - Other, which represents state income tax applicable to other

income and deductions.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

$ 45,464	Account 408.2, Taxes other than income taxes
501	Account 589, Rents
2,075,928	Account 107, Construction work in progress
1,739,350	Account 151, Fuel stock
$3,861,243	

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

See footnote at page 262, line 12, column f.

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

Account 409.2, Income taxes - Other, which represents state income tax applicable to other income and deductions.

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

Amended in accordance with FERC Order No. AC11-132.

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

Amended in accordance with FERC Order No. AC11-132.

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Charged to same account as related goods.

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

$ 69,188	Account 408.2, Taxes other than income taxes
2,749	Account 589, Rents
130,980	Account 107, Construction work in progress
$202,917	

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

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

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

Account 151, Fuel stock

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

$ 935	Account 408.2, Taxes other than income taxes
11,887	Account 589, Rents
341,215	Account 107, Construction work in progress
$354,037	

Schedule Page: 262.2 Line No.: 2 Column: b

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 262.2 Line No.: 2 Column: f

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 262.2 Line No.: 2 Column: l

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress.

Schedule Page: 262.2 Line No.: 4 Column: l

Charged to same account as related goods.

Schedule Page: 262.2 Line No.: 8 Column: f

Represents the tax benefit of interest reclassified to Account 190, Accumulated deferred income taxes.

Schedule Page: 262.2 Line No.: 8 Column: l

Represents interest on uncertain tax positions that are effectively settled, charged to Account 419, Interest and dividend income.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	35,192,133			411.4	1,808,768	
6	10%	5,669,770			420	1,624,452	
7	Idaho	647,021			411.4	65,436	
8	TOTAL	41,508,924				3,498,656	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	10%	440,504			420	440,504	
14							
15	Total Nonutility	440,504				440,504	
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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
33,383,365	48.37		5
4,045,318	30		6
581,585	30		7
38,010,268			8
			9
			10
			11
			12
	30		13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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

Internal Revenue Code 46(f)2

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

Internal Revenue Code 46(f)1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Working Capital Deposits	4,385,114			688,022	5,073,136
2						
3	Reclamation Costs - Trapper Mine	4,736,622			272,022	5,008,644
4						
5	Reclamation Costs - Deseret Mine	527,526	131, 232	10,140		517,386
6						
7	Reclamation Costs - Trail					
8	Mountain Mine	1,087,498	131	2,820		1,084,678
9						
10	Western Coal Carriers Benefits					
11	Obligation	9,124,000	131, 232	998,479	2,090,479	10,216,000
12						
13	Deferred Revenue - Other		421	30,000	85,000	55,000
14						
15	Deferred Compensation Plan	9,630,399	232,241,920	2,189,086	1,927,916	9,369,229
16						
17	Redding Contract (20)	2,750,080	456	549,996		2,200,084
18						
19	Foote Creek Contract (15)	567,662	456	137,640		430,022
20						
21	Environmental Liabilities	9,389,140		2,248,190	5,463,445	12,604,395
22						
23	Unearned Joint Use Pole Contact	3,362,850	454	8,289,184	8,590,744	3,664,410
24						
25	Misc. Security Deposits	11,681			2,000	13,681
26						
27	Hermiston Gas Settlement (5)	408,871	547, 555	408,871		
28						
29	Lease Incentives (10)	124,403	931	48,156		76,247
30						
31	Cowlitz/Lewis River O&M (1)	97,091	535	254,063	269,096	112,124
32						
33	Deferred Credits - Other (1)	23,000	921	23,000		
34						
35	Employee Housing Security Deposits	6,800	131, 232	1,300	9,475	14,975
36						
37	Oregon DSM Loans NPV Unearned					
38	Income (10)	263,870	456	146,411		117,459
39						
40	Cogeneration Bonds-Sunnyside	413,417				413,417
41						
42	Transmission Security Deposits	1,450,000				1,450,000
43						
44	Transmission Service Deposits	2,312,550	232,235,456	3,703,725	2,859,300	1,468,125
45						
46	MCI F.O.G. wire lease (1)	558,451	454	3,352,504	3,352,864	558,811
47	TOTAL	51,231,025		24,577,725	194,300,763	220,954,063

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Unamortized contract values (5)		182.3, 242	2,184,160	168,690,400	166,506,240
3						
4						
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						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	51,231,025		24,577,725	194,300,763	220,954,063

Schedule Page: 269 Line No.: 13 Column: b

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 269 Line No.: 13 Column: e

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 269 Line No.: 15 Column: b

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 269 Line No.: 15 Column: e

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 269 Line No.: 21 Column: c

Account 182.3, Other regulatory assets
Account 232, Accounts payable
Account 557, Other expenses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	11,642,708	83,482,121	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	11,642,708	83,482,121	
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	11,642,708	83,482,121	
18	Classification of TOTAL			
19	Federal Income Tax	10,249,915	73,495,327	
20	State Income Tax	1,392,793	9,986,794	
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
				282	69,552,096	164,676,925	4
							5
							6
							7
					69,552,096	164,676,925	8
							9
							10
							11
							12
							13
							14
							15
							16
					69,552,096	164,676,925	17
							18
					61,231,722	144,976,964	19
					8,320,374	19,699,961	20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	3,330,234,891	538,055,953	290,835,222
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,330,234,891	538,055,953	290,835,222
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,330,234,891	538,055,953	290,835,222
10	Classification of TOTAL			
11	Federal Income Tax	2,931,845,747	473,689,427	256,043,203
12	State Income Tax	398,389,144	64,366,526	34,792,019
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3, 281	72,401,971			3,505,053,651	2
							3
							4
			72,401,971			3,505,053,651	5
							6
							7
							8
			72,401,971			3,505,053,651	9
							10
			63,740,672			3,085,751,299	11
			8,661,299			419,302,352	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	649,677,709	72,759,419	53,094,038
4				
5				
6	Other Deferred Liabilities	30,841,189	15,450,208	11,545,400
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	680,518,898	88,209,627	64,639,438
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)	680,518,898	88,209,627	64,639,438
20	Classification of TOTAL			
21	Federal Income Tax	599,108,781	77,658,333	56,906,755
22	State Income Tax	81,410,117	10,551,294	7,732,683
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
6,442,918	20,543,027		4,481,854		63,980,458	714,741,585	3
							4
							5
181,486			5,382,492	190	2,435,164	31,980,155	6
							7
							8
6,624,404	20,543,027		9,864,346		66,415,622	746,721,740	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
6,624,404	20,543,027		9,864,346		66,415,622	746,721,740	19
							20
5,831,940	18,085,507		8,684,295		58,470,458	657,392,955	21
792,464	2,457,520		1,180,051		7,945,164	89,328,785	22
							23

NOTES (Continued)

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

182.3, Other regulatory assets
190, Accumulated deferred income taxes

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

182.3, Other regulatory assets
190, Accumulated deferred income taxes

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

Account 190, Accumulated deferred income taxes and adjustment related to equity investees.

Footnote amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Investment Tax Credit Regulatory Liability	19,345,346	190	1,013,973		18,331,373
2	Income Tax Reg. Liab. - WA Flow Through	2,426,440	190	7,751,454	8,669,424	3,344,410
3	Gain on Sale of Assets - OR (1)	73,549		64,548	31,408	40,409
4	Gain on Sale of Assets - CA	3,755	421.1	3,755		
5	Injuries & Damage Reserve - OR				186,354	186,354
6	Property Insurance Reserve - OR		924	65,063	3,036,763	2,971,700
7	Property Insurance Reserve - ID		924	7,477	95,689	88,212
8	Property Insurance Reserve - UT		924	683,323		-683,323
9	Property Insurance Reserve - WY				271,761	271,761
10	SMUD Revenue Imputation (11)	9,074,298	440,442	2,338,813	46,657	6,782,142
11	Utah Home Energy Lifeline	203,362	142	2,235,073	2,092,250	60,539
12	BPA Balancing Account - WA	1,482,441			253,222	1,735,663
13	BPA Balancing Account - OR	3,175,146	440,442	477,089		2,698,057
14	Asset Retirement Obligations Reg. Difference	4,407,551			7,763,143	12,170,694
15	Washington Low Income Program	206,049	142	902,041	1,162,644	466,652
16	Misc. Regulatory Liabilities - OR	192,624	142	51		192,573
17	Blue Sky - OR	626,935	456	690,675	1,844,152	1,780,412
18	Blue Sky - WA	48,434	456	99,779	161,217	109,872
19	Blue Sky - CA	18,498	456	31,967	70,381	56,912
20	Blue Sky - UT	920,706	456	1,818,924	2,646,505	1,748,287
21	Blue Sky - ID	2,422	456	41,542	55,600	16,480
22	Blue Sky - WY	54,985	456	158,243	246,092	142,834
23	OR Energy Conservation Charge	2,338,991	456	22,316,839	22,302,044	2,324,196
24	Deferred Arch Coal Settlement (3)	44,269	557	44,269		
25	Renewable Energy Credit Sales Deferral	7,516,235	456	14,535,730	50,862,445	43,842,950
26	Tax Revenue Requirement Adj. - UT	49,234			12,462	61,696
27	2010 Protocol Deferral - OR				2,431,626	2,431,626
28	Powerdale Decommissioning Costs Giveback - UT (2)			180,278	721,112	540,834
29	Regulatory Liability - Reclassifications	7,399,943			2,145,261	9,545,204
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	59,611,213		55,460,906	107,108,212	111,258,519

Schedule Page: 278 Line No.: 1 Column: a

Weighted average life is 46 years.

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

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 431, Other interest expense

Schedule Page: 278 Line No.: 28 Column: c

Account 440, Residential sales
Account 442, Commercial and industrial sales
Account 444, Public street and highway lighting
Account 445, Other sales to public authorities

Schedule Page: 278 Line No.: 29 Column: f

The following schedule summarizes regulatory liabilities reclassifications:

	As of December 31, 2011
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset Actuals - CA	$ 3,007,137
DSM Regulatory Asset Accruals - CA	(248,159)
DSM Regulatory Asset Actuals - UT	8,688,034
DSM Regulatory Asset Accruals - UT	(3,865,060)
Alternative Rate For Energy (CARE) - CA	237,632
Deferred Excess RECs in Rates - UT	16,637
Deferred Excess RECs in Rates - WY	517,165
Deferred Excess Net Power Costs - OR	61,433
Renewable Adjustment Clause - OR	8,816
Deferred Independent Evaluator Fee - OR	191,894
Solar Feed-In Tariff Deferral - CA	246,352
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Property Insurance Reserve - UT	683,323
	$ 9,545,204

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	1,490,664,456	1,357,826,906
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,266,280,218	1,146,322,741
5	Large (or Ind.) (See Instr. 4)	1,136,708,521	1,030,052,681
6	(444) Public Street and Highway Lighting	20,409,578	20,610,361
7	(445) Other Sales to Public Authorities	19,305,829	19,770,416
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	3,933,368,602	3,574,583,105
11	(447) Sales for Resale	351,792,369	501,563,210
12	TOTAL Sales of Electricity	4,285,160,971	4,076,146,315
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,285,160,971	4,076,146,315
15	Other Operating Revenues		
16	(450) Forfeited Discounts	8,445,905	7,411,888
17	(451) Miscellaneous Service Revenues	6,203,507	5,919,271
18	(453) Sales of Water and Water Power	94,873	2,609
19	(454) Rent from Electric Property	20,180,422	19,559,096
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	160,005,183	225,364,091
22	(456.1) Revenues from Transmission of Electricity of Others	73,666,512	67,812,115
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	268,596,402	326,069,070
27	TOTAL Electric Operating Revenues	4,553,757,373	4,402,215,385

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
16,046,111	15,794,444	1,483,134	1,474,909	2
				3
16,489,191	15,969,253	221,634	220,171	4
21,228,737	20,679,453	33,695	33,854	5
144,334	145,032	3,745	3,868	6
398,493	427,352	12	13	7
				8
				9
54,306,866	53,015,534	1,742,220	1,732,815	10
10,766,697	11,414,592			11
65,073,563	64,430,126	1,742,220	1,732,815	12
				13
65,073,563	64,430,126	1,742,220	1,732,815	14

Line 12, column (b) includes $ 236,917,500 of unbilled revenues.

Line 12, column (d) includes 3,270,429 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 were $250,000 or greater during the years ended December 31:

	2011	2010
Account service charges - disconnects/reconnects/returned check charges	$4,155,399	$4,070,201
Customer contract flat rate billings	1,981,186	1,756,340

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

(456) Other electric revenues include the following items that were $250,000 or greater during the years ended December 31:

	2011	2010
Demand-side management revenue	$ 91,535,136	$ 100,095,141
Renewable energy credit sales, net of deferrals and amortization	37,224,673	93,760,900
Wind-based ancillary services	8,045,284	7,281,432
Energy exchange credits	7,988,197	7,822,254
Steam sales	5,818,520	5,719,969
Flyash/by-product sales	3,135,065	2,658,821
Blue Sky revenue	2,482,644	4,167,040
Power sale and exchange agreements	1,091,292	1,091,292
Revenue from generation interconnection and transmission service request studies	903,959	991,746
Maintenance charges for work on transmission facilities	684,158	494,787
Phase shifting equipment fee from Western Electricity Coordinating Council	343,401	455,941

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	CALIFORNIA					
3	06CHCK000R-CA RES CHECK M			1		
4	06LNX00311-LINE EXT 80% GTY		920			
5	06NETMT135-CA RES NET MTR	420	54,891	36	11,667	0.1307
6	06OALT015R-OUTD AR LGT SR	327	75,663	354	924	0.2314
7	06RESD000D-RES SRVC	189,835	24,374,160	18,321	10,362	0.1284
8	06RESDDL06-CA LOW INCOME	116,737	14,790,107	10,049	11,617	0.1267
9	06RGNSV025-CA SM GEN	1	116	28	36	0.1160
10	06RESD0DM9-MULTI FAMILY	237	29,367	8	29,625	0.1239
11	06RESD0DS8-MULT FAM SBMET	1,631	179,300	16	101,938	0.1099
12	UNBILLED REV - UNCOLLECTIBLE		2,000			
13	CA ALT RATE-ENERGY (CARE)		-5,085			
14	REVENUE ADJ. DEFERRED NPC		30,821			
15	REV. ACCOUNTING ADJ.		-146,029			
16	SMUD REVENUE IMPUTATIONS		40,483			
17	06RESD00DN-CA RES SRVC-DEL	93,130	11,852,275	7,251	12,844	0.1273
18	UNBILLED REVENUE	-1,589	258,000			-0.1624
19	IDAHO					
20	07LNX00010-MNTHLY 80%GUAR		1,195			
21	07LNX00035-ADV 80%MO GUAR		1,864			
22	07NETMT135-BPA-ID RES NET		-173			
23	07NETMT135-ID RES NET	1,256	117,981	73	17,205	0.0939
24	07OALCO007-CUST OWN LIGHT	10	3,737	1	10,000	0.3737
25	07OALT07AR-SECURITY AR LG	101	40,685	128	789	0.4028
26	07OALT07AR-BPA-SECURITY AR		-7			
27	07RESD0001-RES SRVC	437,984	44,253,278	43,049	10,174	0.1010
28	07RESD0001-BPA-RES SRVC		-40,770			
29	07RESD0036-RES SRVC-OPTIO	278,605	22,943,676	14,367	19,392	0.0824
30	07RESD0036-BPA-RES		-30,210			
31	07RGNSV23A-ID SM GEN	2	266	7	286	0.1330
32	07RGNSV23A-BPA-ID SM GEN		-1			
33	BPA BALANCING ACCOUNT		-425,065			
34	UNBILLED REV - UNCOLLECTIBLE		-3,000			
35	SMUD REVENUE IMPUTATIONS		53,795			
36	UNBILLED REVENUE	2,003	616,000			0.3075
37	OREGON					
38	01CHCK000R-RES CHECK MTR			1		
39	01COST0004-01RESD0004	5,285,010	287,893,634			0.0545
40	01COSTR023 OR RES GEN SRV	85	4,034			0.0475
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01HABIT004 - 01RESD0004	42,797	2,286,345			0.0534
2	01LNX00102-LINE EXT 80% G		17,216			
3	01LNX00105-CNTRCT $ MIN G		15			
4	01LNX00109-REF/NREF ADV +		1,082			
5	01NETMT135-NET METERING		601,270	1,351		
6	01NETMT135-BPA-NET METERING		-52,447			
7	01NMTOU135-TOU NET METR		5,686	10		
8	01NMTOU135-BPA-TOU NET		-544			
9	01OALT014R-OUTD AR LGT RE	1,177	191,689	2,831	416	0.1629
10	01OALT014R-BPA-OUTD AR LGT		-5,587			
11	01OALTB15R-OR OUTD AR LGT	1,316	214,849	2,788	472	0.1633
12	01OALTB15R-BPA-OR OUTD AR		-5,928			
13	01PTOU0004 - 01RESD0004	19,776	1,106,591			0.0560
14	01RENEW004 - 01RESD0004	216,907	11,447,223			0.0528
15	01RESD0004-RES SRVC		258,622,678	472,083		
16	01RESD0004-BPA-RES SRVC		-25,692,663			
17	01RESD004T - RES Time Option		878,227	1,290		
18	01RESD004T-BPA -RES Time Opt		-79,236			
19	01RGNSB023-SM GEN SVC-RES		4,687	49		
20	01RGNSB023-BPA-SMALL GEN		-335			
21	01UPPL000R-BASE SCH FALL			3		
22	01VIR04136-OR RES VOL INCTV		44,995	75		
23	01VIR04136-BPA-OR RES VOL		-4,020			
24	BPA BALANCING ACCOUNT		296,807			
25	OR GAIN ON SALE OF ASSET		31,823			
26	OR SB 408 RECOVERY		5,794,105			
27	OR SB 838 RECOVERY		-330,320			
28	REV. ACCOUNTING ADJ.		-1,133,927			
29	SMUD REVENUE IMPUTATIONS		513,496			
30	UNBILLED REV - UNCOLLECTIBLE		-1,000			
31	UNBILLED REVENUE	2,496	4,438,000			1.7780
32	UTAH					
33	08CFR00001-MTH FACILITY S		1,055			
34	08CHCK000R-UT RES CHECK M			1		
35	08COOLKPRR-Utah Cool Keeper			99,694		
36	08LNX00001-MTHLY 80% GUAR		3,047			
37	08LNX00005- MTHLY MIN GUAR		1,240			
38	08LNX00013-80% MTHLY MIN		25,916			
39	08LNX00108-ANN COST MTHLY		2,604			
40	08MHTP0006-MOBILE HM &	3,030	198,793	7	432,857	0.0656
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	08MHTP0023-MOBILE HM &	82	6,961	3	27,333	0.0849
2	08MHTP0025-MOBILE HM &	8,133	585,512	10	813,300	0.0720
3	08NETMT135 - Net Metering	6,378	578,839	806	7,913	0.0908
4	08OALT007R-SECURITY AR LG	2,766	781,495	3,026	914	0.2825
5	08PTLD000R-POST TOP LIGHT	2	131	3	667	0.0655
6	08RESD0001-RES SRVC	6,331,128	570,658,484	674,406	9,388	0.0901
7	08RESD0002-RES SRVC-OPTIO	3,003	265,618	331	9,073	0.0885
8	08RESD0003-LIFELINE PRGRM	258,342	22,973,427	31,741	8,139	0.0889
9	08RGNSV006-GEN SRVC-RES	11,361	766,867	103	110,301	0.0675
10	08RGNSV023-GEN SRVC-RES	12,088	1,203,959	5,542	2,181	0.0996
11	08RGNSV06A-UT SM GEN	1,101	81,699	14	78,643	0.0742
12	08RNM23135-UT NET MTR, GEN	55	4,752	10	5,500	0.0864
13	08UPPL000R-BASE SCH FALL			4		
14	REV. ACCOUNTING ADJ.		6,820,393			
15	REVENUE ADJ-DEFERRED NPC		-3,941,200			
16	UNBILLED REV - UNCOLLECTIBLE		15,000			
17	UNBILLED REVENUE	13,178	4,581,000			0.3476
18	WASHINGTON					
19	02LNX00109-REF/NREF ADV+		19			
20	02NETMT135-WA RES NET MTR	493	43,260	27	18,259	0.0877
21	02NETMT135-BPA-WA RES NET		-2,144			
22	02OALTB15R-WA OUTD AR LGT	1,080	158,722	1,164	928	0.1470
23	02OALTB15R-BPA-WA OUTD AR		-4,771			
24	02RESD0016-WA RES SRVC	1,560,018	128,274,965	99,848	15,624	0.0822
25	02RESD0016-BPA-WA RES SRVC		-6,823,839			
26	02RESD0017-BILL ASSISTANCE	64,731	5,283,270	4,022	16,094	0.0816
27	02RESD0017-BPA-BILL		-283,302			
28	02RESD0018-WA 3 PHASE RES	2,264	204,912	87	26,023	0.0905
29	02RESD0018-BPA-WA 3 PHASE		-9,920			
30	02RESD018X-WA 3 PHASE RES	445	39,690	19	23,421	0.0892
31	02RESD018X-BPA-WA 3 PHASE		-1,952			
32	02RGNSB024-WA SM GEN	8	984	35	229	0.1230
33	02RGNSB024-BPA-WA SM GEN		-34			
34	02UPPL000R-BASE SCH FALL		23			
35	BPA BALANCING ACCOUNT		-133,021			
36	REVENUE ADJ.-DEFERRED NPC		-1,396,700			
37	REV. ACCOUNTING ADJ.		-4,022,256			
38	SMUD REVENUE IMPUTATIONS		128,419			
39	WA - CHEHALIS DEFERRAL		-1,320,000			
40	UNBILLED REV - UNCOLLECTIBLE		7,000			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	UNBILLED REVENUE	-3,302	847,000			-0.2565
2	WYOMING					
3	05LNX00102-LINE EXT 80% G		258			
4	05NETMT135-EXPERIMENTAL	1,242	115,087	95	13,074	0.0927
5	05OALT015R-OUTD AR LGT SR	934	135,746	1,084	862	0.1453
6	05RESD0002-WY RES SRVC	947,057	85,092,703	97,464	9,717	0.0898
7	05RESD018X-RES 3 PHASE SR	1	104			0.1040
8	05RGNSV025-WY SM GEN	12	1,130	13	923	0.0942
9	REVENUE ADJ.-DEFERRED NPC		-400,562			
10	REVENUE ACCOUNTING ADJ.		-8,662			
11	SMUD REVENUE IMPUTATIONS		63,655			
12	UNBILLED REV - UNCOLLECTIBLE		5,000			
13	UNBILLED REVENUE	-3,426	672,000			-0.1961
14	05LNX00109-REF/NREF ADV+		244			
15	05RESD0002-WY RES SRVC	135,793	12,280,173	12,512	10,853	0.0904
16	05RGNSV025-WY SM GEN		39	1		
17	09OALT207R-SECURITY AR LG	77	22,193	92	837	0.2882
18	05NETMT135 - EXPERIMENTAL	203	18,746	12	16,917	0.0923
19	09RES00002			2		
20	09RESD0002			4		
21	UNBILLED REVENUE	-2,420	-98,000			0.0405
22	LESS MULTIPLE BILLINGS			-123,218		
23						
24	TOTAL RESIDENTIAL SALES	16,046,111	1,490,664,456	1,483,134	10,819	0.0929
25						
26	COMMERCIAL SALES					
27	CALIFORNIA					
28	06CHCK000N-CA NRES CHECK			1		
29	06GNSV0025-CA GEN SRVC	58,329	8,860,337	6,872	8,488	0.1519
30	06GNSV025F-GEN SRVC-< 20	933	156,820	89	10,483	0.1681
31	06GNSV0A32-GEN SRVC-20 KW	83,279	10,386,699	967	86,121	0.1247
32	06LGSV048T-LRG GEN SERV	61,254	5,187,557	13	4,711,846	0.0847
33	06LGSV0A36-LRG GEN SRVC-O	77,114	8,206,586	174	443,184	0.1064
34	06LNX00102-LINE EXT 80% G		11,739			
35	06LNX00103-LINE EXT 80% G		1,018			
36	06LNX00105-CNTRCT $ MIN G		4,585			
37	06LNX00109-REF/NREF ADV +		64,204			
38	06LNX00300-80% MTHLY MIN GU		17,435			
39	06LNX00311-LINE EXT 80% GUAR		5,977			
40	06NMT36135-CA GEN SVC NET	343	42,464	1	343,000	0.1238
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	06OALT015N-OUTD AR LGT SR	724	170,425	524	1,382	0.2354
2	06RCFL0042-AIRWAY & ATHLE	195	35,290	39	5,000	0.1810
3	06WHS31025-COMM WTR HEATI	64	9,510	28	2,286	0.1486
4	06NMT25135-GN SVC NET<20K	43	6,121	2	21,500	0.1423
5	06NMT32135-GN SVC NET>20K	306	40,486	3	102,000	0.1323
6	REVENUE ADJ.-DEFERRED NPC		22,411			
7	REV. ACCOUNTING ADJ.		-88,795			
8	SMUD REVENUE IMPUTATIONS		29,045			
9	06LNX00110-REF/NREF ADV +		10,029			
10	UNBILLED REVENUE	-1,317	109,000			-0.0828
11	IDAHO					
12	07CISH0019-COMM & IND SPA	6,506	488,217	117	55,607	0.0750
13	07GNSV0006-GEN SRVC-LRG P	192,191	14,295,160	950	202,306	0.0744
14	07GNSV0009-GEN SRVC-HI VO	43,056	2,302,352	1	43,056,000	0.0535
15	07GNSV0023-GEN SRVC-SML P	134,778	11,734,851	6,424	20,980	0.0871
16	07GNSV0035-GEN SRVCOPTION	553	34,208	2	276,500	0.0619
17	07GNSV006A-GEN SRVC-LRG P	26,890	2,106,252	192	140,052	0.0783
18	07GNSV006A-BPA-GEN SRVC-LRG		-3,275			
19	07GNSV023A-GEN SRVC-SML P	20,802	1,865,532	1,463	14,219	0.0897
20	07GNSV023A-BPA-GEN SRVC SML		-2,569			
21	07GNSV023F-GEN SRVC-SML P	17	2,720	7	2,429	0.1600
22	07LNX00010-MNTHLY 80%GUAR		4,064			
23	07LNX00035-ADV 80%MO GUAR		296,585			
24	07LNX00040-ADV+REFCHG+80%		75,456			
25	07OALT007N-SECURITY AR LG	233	86,805	178	1,309	0.3726
26	07OALT07AN-SECURITY AR LG	11	4,477	13	846	0.4070
27	07OALT07AN-BPA-SECURITY AR		-1			
28	07LNX00312-ID LINE EXT		7,912			
29	07NMT06135-ID NET MTR-LRG	1,460	114,841	3	486,667	0.0787
30	07NMT23135-ID NET MTR-SM GEN	383	30,069	9	42,556	0.0785
31	07LNX00015-ANNUAL 80%GUAR		1,332			
32	07LNX00311-LINE EXT 80% GUAR		51,759			
33	07LNX00300-80% MTHLY MIN GU		10,218			
34	BPA BALANCING ACCOUNT		7,870			
35	SMUD REVENUE IMPUTATIONS		30,069			
36	UNBILLED REVENUE	18,220	1,490,000			0.0818
37	OREGON					
38	01COST0023-OR GEN SRV-COST	991,345	53,805,499			0.0543
39	01COST0048-01LGSV0048	766,124	37,858,384			0.0494
40	01COST023F-OR GEN SRV-COST	3,074	178,070			0.0579
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01COSTB023-OR GEN SRV-CST	84,395	4,742,100			0.0562
2	01COSTL030-OR LG GEN	1,045,085	52,104,707			0.0499
3	01COSTS028-OR GEN SRV	1,907,159	103,614,223			0.0543
4	01GNSB0023-BPA DISC<30kW		-389,391			
5	01GNSB0023-BPA-OR GEN SRV		5,915,215	14,351		
6	01GNSB0028-BPA-OR GEN SRV		2,520,647	530		
7	01GNSB023T-BPA-OR GEN		22,732	49		
8	01GNSV0023-OR GEN SRV<30kW		46,264,827	58,009		
9	01GNSV0028-OR GEN SRV>30kW		44,900,970	8,818		
10	01GNSV023F-OR GEN SRV-FLAT	10,601	1,571,173	796	13,318	0.1482
11	01GNSV023M-OR GEN SRV-MANU	30	2,789	1	30,000	0.0930
12	01GNSV023T-OR GEN SRV-TOU		170,956	226		
13	01HABT0023-OR HABITAT BLEND	2,422	133,526			0.0551
14	01HABTB023-OR HABITAT BLEND	187	10,719			0.0573
15	01LGSB0030-BPA-GEN DEL		-209,474			
16	01LGSB0030-GEN DEL SRV>200		841,257	25		
17	01LGSV0030-OR LRG GEN		20,457,751	605		
18	01LGSV0048-1000kW AND OVR		9,248,066	100		
19	01LGSV048M-LRG GEN SRVC 1	59,540	3,271,747	1	59,540,000	0.0550
20	01LNX00100-LINE EXT 60% GUAR		2,140			
21	01LNX00102-LINE EXT 80% GUAR		407,241			
22	01LNX00103-LINE EXT 80% GUAR		4,078			
23	01LNX00105-CNTRCT $ MIN G		14,281			
24	01LNX00109-REF/NREF ADV +		1,540,407			
25	01LNX00110-REF/NREF ADV +		3,432			
26	01LNX00120-LINE EXT 60% GUAR		266			
27	01LNX00300-LINE EXT 80% GUAR		151,589			
28	01LNX00310-LINE EXT CONTRACT		1,914			
29	01LNX00311-LINE EXT 80% GUAR		122,855			
30	01LNX00314-LINE EXT 60% GUAR		-789			
31	01LPRS047M-PART REQ SRVC	31,078	2,374,000	3	10,359,333	0.0764
32	01NMT23135-OR NET MTR		95,249	125		
33	01NMT23135-BPA-OR NET MTR		-127			
34	01OALT014N-OUTD AR LGT NR	753	125,558	1,139	661	0.1667
35	01OALT014N-BPA-OUTD AR LGT		-3,548			
36	01OALT015N-OUTD AR LGT NR	5,784	867,242	2,992	1,933	0.1499
37	01OALTB15N-OUTD AR LGT NR	825	139,203	1,126	733	0.1687
38	01OALTB15N-W/BPA-OUTD AR		-3,710			
39	01PTOU0023 OR GEN SRV, TOU	3,569	196,327			0.0550
40	01PTOUB023 OR GEN SRV, TOU	422	23,720			0.0562
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01RCFL0054-REC FIELD LGT	1,211	124,018	104	11,644	0.1024
2	01RENW0023 OR RENW USAGE	8,331	460,280			0.0552
3	01RENWB023 OR RENEWABLE	467	26,819			0.0574
4	01STDAY023-OR DAY STD OFR,	2,257	133,476			0.0591
5	01STDAY028-OR DAY STD OFF,	11,586	666,682			0.0575
6	01STDAY030-OR STD DAY OFF	4,343	237,685			0.0547
7	01VIR23136-OR VOL		17,046	16		
8	01VIR23136-BPA-OR VOL		-64			
9	01VIR28136-OR VOL		75,613	16		
10	01VIR28136-BPA-OR VOL		-193			
11	01VIR30136-OR VOL		36,696	2		
12	01VIR48136-OR VOL		15,438	1		
13	BPA BALANCING ACCOUNT		327,150			
14	01LGSB0048-BPA-LG GEN		-14,568			
15	01LGSB0048-LG GEN		53,491	1		
16	01NMT28135-OR NET MTR		350,560	61		
17	01NMT30135-OR NET MTR		420,587	13		
18	01NMT48135-NET MTR GEN		97,472	2		
19	01LGSV028M-OR LGSV<1000 kW	366	29,665	1	366,000	0.0811
20	01LGSV030M-OR LGSV 200 kW	1,650	118,360	1	1,650,000	0.0717
21	01GNSV0728-OR GEN SVC DIR		190,713	8		
22	01GNSV0730-OR GEN SVC DIR		2,783,141	34		
23	01GNSV0748 LG GEN SVC DIR		351,512	1		
24	OR GAIN ON SALE OF ASSET		23,238			
25	OR SB 408 RECOVERY		5,079,948			
26	OR SB 838 RECOVERY		-211,119			
27	REV. ACCOUNTING ADJ.		-828,028			
28	SMUD REVENUE IMPUTATIONS		451,190			
29	UNBILLED REVENUE	25,791	5,869,000			0.2276
30	UTAH					
31	08ABL-NRES-APPLICANT BUILT		21,537			
32	08CFR00051-MTH FAC SRVCHG		38,902			
33	08CFR00052-ANN FAC SVCCHG		2			
34	08COOLKPRN - A/C DIRECT LOAD			4,070		
35	08GNSV0006-GEN SRVC-DISTR	4,821,904	342,243,542	10,823	445,524	0.0710
36	08GNSV0009-GEN SRVC-HI VO	320,818	15,689,388	26	12,339,154	0.0489
37	08GNSV0023-GEN SRVC-DISTR	1,252,553	106,619,601	72,954	17,169	0.0851
38	08GNSV006A-GEN SRVC-ENERG	212,050	20,667,534	1,858	114,128	0.0975
39	08GNSV006B-GEN SRVC-DEM&	10,245	732,178	23	445,435	0.0715
40	08GNSV006M-MNL DIST VOLTG	3,598	206,635	7	514,000	0.0574
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	08GNSV009A-GEN SRVC HI VO	25,108	1,347,375	2	12,554,000	0.0537
2	08GNSV009M-MANL HI VOLT			1		
3	08GNSV023F-GEN SRVC FIXED	1,308	159,213	124	10,548	0.1217
4	08GNSV023M-GNSV DIST VOLT	109	8,923	5	21,800	0.0819
5	08GNSV06AM-MNL ENERGY TOD	39	16,431	1	39,000	0.4213
6	08GNSV06MN-GNSV DIST VOLT	28,700	1,935,040	457	62,801	0.0674
7	08LNX00002-MTHLY 80% GUAR		453,123			
8	08LNX00004-ANNUAL 80%GUAR		15,466			
9	08LNX00006-FIXD MTHLY MIN		4,668			
10	08LNX00008-ANNUALMIN GUAR		12,167			
11	08LNX00014-80% MIN MNTHLY		2,071,812			
12	08LNX00017-ADV/REF&80%ANN		238,282			
13	08LNX00158-ANNUALCOST MTH		33,793			
14	08LNX00300-LINE EXT 80%+MO		138,404			
15	08LNX00310-IRR 80% ANNUAL MIN		56,951			
16	08LNX00312 UT IRG LINE EXT		9,230			
17	08NMT06135-UT NET MTR GEN	20,590	1,558,526	49	420,204	0.0757
18	08NMT08135-NET METERING GEN	10,014	640,007	2	5,007,000	0.0639
19	08NMT23135 -UT NET MTR	1,480	126,695	76	19,474	0.0856
20	08NMT6A135-NET METERING GEN	46	9,206	1	46,000	0.2001
21	08OALT007N-SECURITY AR LG	8,419	1,952,703	4,432	1,900	0.2319
22	08POLE0075-POLES W/LIGHT		84	1		
23	08PRSV031M-BKUP MNT&SUPPL	19,142	1,266,265	2	9,571,000	0.0662
24	08PTLD000N-POST TOP LIGHT	6	453	2	3,000	0.0755
25	08TOSS015F-TRAFFIC SIG NM	160	15,143	24	6,667	0.0946
26	08TOSS0015-TRAF & OTHER S	1,661	158,903	717	2,317	0.0957
27	08MONL0015-MTR OUTDONIGHT	14,736	1,048,299	400	36,840	0.0711
28	REV. ACCOUNTING ADJ.		7,083,961			
29	REVENUE ADJ-DEFERRED NPC		-4,093,313			
30	08LNX00311-LINE EXT 80%		251,879			
31	08GNSV0008-UT GEN SVC	1,002,489	61,082,880	153	6,552,216	0.0609
32	08GNSV008M-UT GEN SVC	32,868	2,163,552	5	6,573,600	0.0658
33	UNBILLED REVENUE	11,854	3,346,000			0.2823
34	WASHINGTON					
35	02GNSB0024-WA GEN SRVC DO	41,410	3,709,216	3,199	12,945	0.0896
36	02GNSB0024-W/BPA-WA GEN		-181,542			
37	02GNSB024F-GEN SRVC DOM/F	167	18,921	6	27,833	0.1133
38	02GNSB024F-W/BPA-GEN SRVC		-4			
39	02GNSB24FP-WA GEN SVC	307	111,414	91	3,374	0.3629
40	02GNSB24FP-W/BPA-WA GEN SVC		-1,357			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	02GNSV0024-WA GEN SRVC	480,171	39,437,604	14,642	32,794	0.0821
2	02GNSV024F-WA GEN SRVC-FL	1,115	135,672	112	9,955	0.1217
3	02LGSB0036-LRG GEN SVC IRG	81,441	5,596,611	101	806,347	0.0687
4	02LGSB0036-W/BPA-LRG GENSVC		-354,693			
5	02LGSV0036-WA LRG GEN SRV	673,418	47,142,457	810	831,380	0.0700
6	02LGSV048T-LRG GEN SRVC 1	141,957	8,969,763	26	5,459,885	0.0632
7	02LNX00102-LINE EXT 80% G		164,935			
8	02LNX00103-LINE EXT 80% G		2,221			
9	02LNX00105-CNTRCT $ MIN G		700			
10	02LNX00109-REF/NREF ADV +		410,124			
11	02LNX00110-REF/NREF ADV +		5,226			
12	02LNX00112-YR INCURRED CH		669			
13	02LNX00300-LINE EXT 80% G		8,452			
14	02LNX00310-IRG 80% ANN		3,575			
15	02LNX00311-LINE EXT 80%		42,272			
16	02LNX00312-WA IRG LINE EXT		4,004			
17	02OALT015N-WA OUTD AR LGT	1,642	224,242	851	1,929	0.1366
18	02OALTB15N-WA OUTD AR LGT	593	86,766	518	1,145	0.1463
19	02OALTB15N-W/BPA-WA OUTD AR		-2,614			
20	02RCFL0054-WA REC FIELD L	244	22,158	28	8,714	0.0908
21	02ZZMERGCR-MERGER CREDITS		1			
22	02NMT24135, Net metering, WA	254	21,873	5	50,800	0.0861
23	02NMT24135-BPA-Net metering, WA		-2			
24	02NMT36135-WA NET MTR LRG	105	10,970	1	105,000	0.1045
25	BPA BALANCING ACCOUNT		-4,392			
26	REVENUE ADJ-DEFERRED NPC		-1,154,477			
27	REV. ACCOUNTING ADJ.		-3,084,534			
28	SMUD REVENUE IMPUTATIONS		110,940			
29	WA - CHEHALIS DEFERRAL		-1,020,000			
30	UNBILLED REVENUE	-983	606,000			-0.6165
31	WYOMING					
32	05CHCK000N-WY NRES			1		
33	05GNS28025-GEN SVC TRANS		-24			
34	05GNSV0025-WY GEN SRVC	236,772	19,218,400	17,995	13,158	0.0812
35	05GNSV0028-GEN SVC>15kW	899,070	67,465,273	3,351	268,299	0.0750
36	05GNSV025F-GEN SRVC-FL RA	994	139,421	183	5,432	0.1403
37	05LGSV0046-WY LRG GEN SRV	254,406	15,138,627	20	12,720,300	0.0595
38	05LGSV048T-LRG GENSRV TIM	10,430	657,345	1	10,430,000	0.0630
39	05LNX00100-LINE EXT 60% G		68			
40	05LNX00102-LINE EXT 80% G		548,373			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05LNX00103-LINE EXT 80% G		-861			
2	05LNX00105-CNTRCT $ MIN G		5,350			
3	05LNX00109-REF/NREF ADV +		649,384			
4	05LNX00110-REF/NREF ADV+		839			
5	05LNX00114-TEMP SVC 12MO>		1,162			
6	05N2825135-NET MTR TRANSI	2	119			0.0595
7	05NMT25135-WY NET MTR	206	15,685	11	18,727	0.0761
8	05NMT28135-NET MTR SM GEN	3,719	314,139	12	309,917	0.0845
9	05OALT015N-OUTD AR LGT SR	2,873	422,498	1,736	1,655	0.1471
10	05RCFL0054-WY REC FIELD L	738	56,497	51	14,471	0.0766
11	05LNX00300-LINE EXT 80%		76,778			
12	05LNX00311-LINE EXT 80%		76,210			
13	REVENUE ADJ-DEFERRED NPC		-573,382			
14	REV. ACCOUNTING ADJ.		-11,704			
15	SMUD REVENUE IMPUTATIONS		90,453			
16	UNBILLED REVENUE	-21,757	-1,013,000			0.0466
17	05GNS28025-GEN SVC	-1	-115			0.1150
18	05GNSV0025-WY GEN SRVC	32,067	2,576,558	2,327	13,780	0.0803
19	05GNSV0028-GEN SVC>15kW	113,651	8,466,185	447	254,253	0.0745
20	05GNSV025F-GEN SRVC-FL RA	188	19,698	32	5,875	0.1048
21	05GNSV028M-GEN SVC>15kW	1,957	138,245	1	1,957,000	0.0706
22	05LGSV048T-LRG GEN SRV TIM	40,962	3,084,085	1	40,962,000	0.0753
23	05LNX00102-LINE EXT 80% G		7,891			
24	05LNX00109-REF/NREF ADV +		160,392			
25	05LNX00110-REF/NREF ADV +		135			
26	05LNX00114-TEMP SVC		1,054			
27	09GNSV0025-GEN SVC-SINGLE		-61			
28	05OALT015N-OUTD AR LGT SR	3	639	2	1,500	0.2130
29	05NMT25135-WY NET MTR	88	5,901	2	44,000	0.0671
30	05NMT28135-NET MTR SMALL	334	28,700	3	111,333	0.0859
31	09OALT207N-SECURITY AR LG	276	69,781	137	2,015	0.2528
32	09MONL0213-WY MTR OUTDOOR	41	2,506	4	10,250	0.0611
33	05LNX00300-LINE EXT 80%		919			
34	05LNX00311-LINE EXT 80%		8,968			
35	UNBILLED REVENUE	-4,328	-251,000			0.0580
36	LESS MULTIPLE BILLINGS			-28,517		
37						
38	TOTAL COMMERCIAL SALES	16,489,191	1,266,280,218	221,634	74,398	0.0768
39						
40	INDUSTRIAL SALES					
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	CALIFORNIA					
2	06GNSV0025-CA GEN SRVC	644	101,530	93	6,925	0.1577
3	06GNSV0A32-GEN SRVC-20kW	1,974	281,787	26	75,923	0.1427
4	06LGSV048T-LRG GEN SERV	35,743	3,016,970	5	7,148,600	0.0844
5	06LGSV0A36-LRG GEN SRVC-O	4,287	518,121	11	389,727	0.1209
6	REVENUE ADJ.-DEFERRED NPC		4,248			
7	REV. ACCOUNTING ADJ.		127,564			
8	SMUD REVENUE IMPUTATIONS		4,638			
9	UNBILLED REVENUE	-1,841	-83,000			0.0451
10	IDAHO					
11	07CFR00001-MTH FACILITY S		2,217			
12	07CISH0019-COMM & IND SPA	125	9,942	3	41,667	0.0795
13	07GNSV0006-GEN SRVC-LRG P	89,034	5,701,081	108	824,389	0.0640
14	07GNSV0009-GEN SRVC-HI VO	78,936	4,324,720	11	7,176,000	0.0548
15	07GNSV0023-GEN SRVC-SML P	11,126	946,962	351	31,698	0.0851
16	07GNSV0035-GEN SRVCOPTION	1,039	58,332	1	1,039,000	0.0561
17	07GNSV006A-GEN SRVC-LRG P	3,930	314,686	29	135,517	0.0801
18	07GNSV006A-BPA-GEN SRVC-LRG		-510			
19	07GNSV023A-GEN SRVC-SML P	2,120	208,629	243	8,724	0.0984
20	07GNSV023A-BPA-GEN SRVC-SML		-173			
21	07GNSV023S-ID TRAFFIC SIGNALS	9	1,205	3	3,000	0.1339
22	07LNX00035-ADV 80%MO GUAR		850			
23	07LNX00108-ANN COST MTHLY		1,996			
24	07LNX00300-80% MONTHLY MIN		1,443			
25	07OALT007N-SECURITY AR LG	13	5,019	17	765	0.3861
26	07OALT07AN-SECURITY AR LG		232	1		
27	07SPCL0001	1,414,300	66,260,087	1	1,414,300,000	0.0469
28	07SPCL0002	109,897	5,067,425	1	109,897,000	0.0461
29	BPA BALANCING ACCOUNT		2,784			
30	SMUD REVENUE IMPUTATIONS		127,194			
31	UNBILLED REVENUE	16,216	914,000			0.0564
32	OREGON					
33	01COST0023 OR GEN SRV COST	20,905	1,138,923			0.0545
34	01COST0048-01LGSV0048	1,702,342	82,639,777			0.0485
35	01COST023F-OR GEN	1	60			0.0600
36	01COSTB023-OR GEN SRV	368	20,766			0.0564
37	01COSTL030-OR LRG GEN SRV	196,781	9,868,456			0.0501
38	01COSTS028 OR GEN SERV	94,394	5,112,529			0.0542
39	01GNSB0023-BPA DISC<30 kW		-1,692			
40	01GNSB0023-BPA-OR GEN		28,905	66		
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01GNSB0028-BPA-OR GEN		13,273	5		
2	01GNSV0023 OR GEN SRV<30kW		1,029,172	1,162		
3	01GNSV0028 OR GEN SRV>30kW		2,956,783	479		
4	01GNSV023F-OR GEN SR FLAT	2	684	2	1,000	0.3420
5	01GNSV023M-OR GEN SRV	35	7,829	1	35,000	0.2237
6	01GNSV023T OR GEN SRV TOU		2,988	4		
7	01GNSV0728-OR GEN SVC DIR		230			
8	01GNSV0748-OR GEN SVC DIR		38,487	2		
9	01HABT0023 OR HABITAT	12	680			0.0567
10	01LGSV0030-OR LRG GEN		5,877,368	153		
11	01LGSV0048-1000kW AND OVR		16,928,484	103		
12	01LGSV048M-LRG GEN SRVC 1	106,528	6,992,183	4	26,632,000	0.0656
13	01LNX00102-LINE EXT 80% G		54,201			
14	01LNX00120-Line Extension 60% G		3,695			
15	01LNX00300-LINE EXT 80%		7,828			
16	01LPRS047M-PART REQ	106,656	6,043,074	2	53,328,000	0.0567
17	01NMT23135-OR NET MTR		163			
18	01NMT28135-OR NET MTR		14,790	4		
19	01NMT30135-OR NET MTR		1,665	1		
20	01OALT014N-OUTD AR LGT NR	2	314	5	400	0.1570
21	01OALT014N-BPA-OUTD AR LGT		-10			
22	01OALT015N-OUTD AR LGT	328	47,483	140	2,343	0.1448
23	01OALTB15N-OR OUTD AR LGT	3	385	5	600	0.1283
24	01OALTB15N-W/BPA-OR OUTD AR		-11			
25	01PTOU0023 OR GEN SRV TOU	49	2,752			0.0562
26	01RENW0023 OR RENW USAGE	142	7,639			0.0538
27	01RENWB023-OR RENEWABLE	1	33			0.0330
28	BPA BALANCING ACCOUNT		1,003			
29	01STDAY023-OR DAY STD OFR	20	1,205			0.0603
30	01STDAY028-OR DAY STD OFR	174	10,577			0.0608
31	01VIR23136-OR VOL		325	1		
32	01VIR30136-OR VOL		8,707	1		
33	01ZZMERGCR-MERGER CREDITS		-1			
34	OR GAIN ON SALE OF ASSET		8,262			
35	OR SB 408 RECOVERY		2,344,591			
36	OR SB 838 RECOVERY		-100,849			
37	REV. ACCOUNTING ADJ.		-294,418			
38	SMUD REVENUE IMPUTATIONS		209,836			
39	UNBILLED REVENUE	-1,286	1,414,000			-1.0995
40	UTAH					
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	08CFR00051-MTH FAC SRVCHG		14,047			
2	08EFOP0021-ELEC FURNACE O	1,953	160,634	2	976,500	0.0822
3	08EFOP021M-ELEC FURNACE O	1,513	150,840	3	504,333	0.0997
4	08GNSV0006-GEN SRVC-DISTR	686,768	51,664,669	1,152	596,153	0.0752
5	08GNSV0009-GEN SRVC-HI VO	2,783,348	125,859,808	108	25,771,741	0.0452
6	08GNSV0023-GEN SRVC-DISTR	58,507	5,037,987	3,536	16,546	0.0861
7	08GNSV006A-GEN SRVC-ENERG	53,425	5,719,851	257	207,879	0.1071
8	08GNSV006B-GEN SRVC-DEM	7,063	517,917	8	882,875	0.0733
9	08GNSV009A-GEN SRVC HI VO	19,343	1,306,742	6	3,223,833	0.0676
10	08GNSV009M-MANL HIGH	855,648	36,978,810	11	77,786,182	0.0432
11	08GNSV023F-GEN SRVC FIXED	4	2,141	1	4,000	0.5353
12	08GNSV06MN-GNSV DIST VOLT	1,266	97,923	28	45,214	0.0773
13	08GNSV09AM-MAN TOD HIVOLT	1,201	103,647	1	1,201,000	0.0863
14	08LNX00002-MTHLY 80% GUAR		30,853			
15	08LNX00004-ANNUAL 80%GUAR		8,213			
16	08LNX00014-80% MIN		41,093			
17	08LNX00017-ADV/REF&80%ANN		3,361			
18	08LNX00311-LINE EXT 80%		4,251			
19	08LNX00300-LINE EXT 80% PLUS		51,753			
20	08LNX00310-IRR 80% ANNUAL MIN		6,141			
21	08OALT007N-SECURITY AR	1,330	271,420	494	2,692	0.2041
22	08TOSS0015-TRAF & OTHER S	21	2,104	11	1,909	0.1002
23	08MONL0015-MTR OUTDONIGHT	8	2,954	7	1,143	0.3693
24	08NMT06135-UT NET MTR GEN	606	47,136	2	303,000	0.0778
25	08NMT23135-UT NET MTR GEN<25	59	4,021	1	59,000	0.0682
26	08PRSV031M-BKUP MNT&SUPP	2,929	534,257	1	2,929,000	0.1824
27	08SPCL0001	524,877	22,064,619	1	524,877,000	0.0420
28	08SPCL0002	897,631	29,293,488	1	897,631,000	0.0326
29	08SPCL0003	985,891	40,053,038	1	985,891,000	0.0406
30	08SPCL0005	250,829	10,081,122	1	250,829,000	0.0402
31	REV. ACCOUNTING ADJ.		4,376,938			
32	REVENUE ADJ-DEFERRED NPC		-2,528,875			
33	08GNSV06AM-MNL ENERGY TOD	318	34,027	2	159,000	0.1070
34	08GNSV0008-UT GEN SVC	955,113	60,695,848	110	8,682,845	0.0635
35	08GNSV008M-UT GEN SVC	59,957	3,823,398	7	8,565,286	0.0638
36	UNBILLED REVENUE	-7,716	2,436,000			-0.3157
37	WASHINGTON					
38	02GNSB0024-WA GEN SRVC	1,954	178,547	95	20,568	0.0914
39	02GNSB0024-W/BPA-WA GEN		-8,572			
40	02GNSB24FP-WA GEN SVC	5	1,941	1	5,000	0.3882
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	02GNSB24FP-W/BPA-WA GEN SVC		-21			
2	02GNSV0024-WA GEN SRVC	15,408	1,296,096	360	42,800	0.0841
3	02GNSV024F-WA GEN SRVC-FL	33	7,513	4	8,250	0.2277
4	02LGSV0036-WA LRG GEN SRV	114,346	8,188,158	115	994,313	0.0716
5	02LGSV048T-LRG GEN SRV 1	669,856	37,359,595	32	20,933,000	0.0558
6	02OALT015N-WA OUTD AR LGT	121	15,538	42	2,881	0.1284
7	02OALTB15N-WA OUTD AR LGT	29	4,313	16	1,813	0.1487
8	02OALTB15N-W/BPA-WA OUTD AR		-130			
9	02PRSV47TM-LRG PART REQMT	1,379	234,625	1	1,379,000	0.1701
10	02LGSB0036-LRG GEN SVC IRG	3,633	412,006	26	139,731	0.1134
11	02LGSB0036-W/BPA-LRG GENSVC		-16,054			
12	BPA BALANCING ACCOUNT		-116			
13	REVENUE ADJ-DEFERRED NPC		-628,612			
14	REV. ACCOUNTING ADJ.		-1,405,927			
15	SMUD REVENUE IMPUTATIONS		63,473			
16	WA - CHEHALIS DEFERRAL		-510,000			
17	UNBILLED REVENUE	-8,814	-171,000			0.0194
18	WYOMING					
19	05GNS28025-GEN SVC	-9	-653			0.0726
20	05GNSV0025-WY GEN SRVC	21,657	1,642,401	1,143	18,948	0.0758
21	05GNSV0028-GEN SRVC>15 kW	273,549	18,235,853	462	592,097	0.0667
22	05GNSV025F-GEN SRVC-FL RA	21	2,802	6	3,500	0.1334
23	05LGSV0046-WY LRG GEN	1,609,697	90,489,330	54	29,809,204	0.0562
24	05LGSV046M-WY LRG GEN	112,857	6,100,642	2	56,428,500	0.0541
25	05LGSV048M-TOU>1000kW MAN	1,284,140	60,438,382	2	642,070,000	0.0471
26	05LGSV048T-LRG GENSRV TIM	1,349,911	64,100,080	10	134,991,100	0.0475
27	05LNX00100-LINE EXT 60% G		46,441			
28	05LNX00102-LINE EXT 80% G		253,102			
29	05LNX00105-CNTRCT $ MIN G		43,462			
30	05LNX00109-REF/NREF ADV+		206,298			
31	05OALT015N-OUTD AR LGT SR	85	11,495	44	1,932	0.1352
32	05PRSV033M-PART SERV REQ	834,631	45,495,832	5	166,926,200	0.0545
33	05RFNDCENT-CENTRALIA RFND		9,264			
34	05UPPL000N-BASE SCH FALL		3,289			
35	REVENUE ADJ-DEFERRED NPC		-2,687,500			
36	REV. ACCOUNTING ADJ.		-38,480			
37	SMUD REVENUE IMPUTATIONS		423,320			
38	05LNX00300-LINE EXT 80%		29,250			
39	05LNX00311-LINE EXT 80%		24,552			
40	UNBILLED REVENUE	31,489	4,914,000			0.1561
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

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	05GNSV0025-WY GEN SVC	4,100	331,493	297	13,805	0.0809
2	05GNSV0028-GEN SVC>15 kW	36,600	2,508,450	66	554,545	0.0685
3	05GNSV028M-GEN SVC>15 kW	5,747	319,762	4	1,436,750	0.0556
4	05LGSV0046-WY LRG GEN SRV	26,050	1,622,793	3	8,683,333	0.0623
5	05LGSV048M-TOU>1000kW MAN	284,131	13,134,121	3	94,710,333	0.0462
6	05LGSV048T-LRG GENSRV	1,120,092	54,148,346	10	112,009,200	0.0483
7	05LNX00102-LINE EXT 80% G		6,096			
8	05LNX00109-REF/NREF ADV +		652,620			
9	05PRSV033M-PART SERV REQ	109,250	5,486,597	3	36,416,667	0.0502
10	09OALT207N-SECURITY AR	5	1,048	3	1,667	0.2096
11	UNBILLED REVENUE	2,477	456,000			0.1841
12	LESS MULTIPLE BILLINGS			-989		
13						
14	TOTAL INDUSTRIAL SALES	20,041,331	1,042,747,140	10,616	1,887,842	0.0520
15						
16	IRRIGATION SALES					
17	CALIFORNIA					
18	06APSV0020-AG PMP SRVC	59,227	7,099,551	1,372	43,168	0.1199
19	06LGSV048T-LRG GEN SERV	2,272	207,024	1	2,272,000	0.0911
20	06LNX00102-LINE EXT 80% G		737			
21	06LNX00103-LINE EXT 80% G		4,085			
22	06LNX00110-REF/NREF ADV +		36,328			
23	06LNX00310-IRG 80% ANN		1,631			
24	06LNX00312-CA IRG LINE EXT		1,189			
25	06USBR0020-KLAM IRG ONPRJ	21,872	2,953,055	658	33,240	0.1350
26	06LNX00109-REF/NREF ADV +		200			
27	IRR DEMAND CHG ACCR		3,800			
28	IRRIGATION UNBILLED	32	3,000			0.0938
29	REV. ACCOUNTING ADJ.		-73,869			
30	IDAHO					
31	07APSA010L-IRG & Pump Large	476,465	38,093,923	3,547	134,329	0.0800
32	07APSA010S-BPA-IRG & PUMP		-4			
33	07APSA010S-IRG & Pump Small	4,920	494,033	475	10,358	0.1004
34	07APSAL10X-IRG & PUMP-Large	33,664	2,822,897	493	68,284	0.0839
35	07APSAS10X-IRG & PUMP-Small	1,529	161,155	166	9,211	0.1054
36	07APSVCNLL-LRG LOAD CANAL	25,099	1,821,971	78	321,782	0.0726
37	07APSVCNLS-SML LOAD CANAL	129	14,582	18	7,167	0.1130
38	07LNX00015-ANNUAL 80%		6,768			
39	07LNX00040-ADV+REFCHG+80%		178,482			
40	07LNX00310 80% ANN GTY		176			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	07LNX00312-ID LINE EXT		27,008			
2	07APSN010L-ID LG IRR & PUMP	3,680	328,138	47	78,298	0.0892
3	07APSN010L-BPA-ID LG IRR 3 PH		-9			
4	07APSN010S-IRR SMALL 3PHASE	318	29,021	22	14,455	0.0913
5	07APSNS10X-IRR SMALL 3PHA	3	724	1	3,000	0.2413
6	IRRIGATION BPA BAL ACCT		-778,726			
7	UNBILLED REV - IRRIGATION	-91	-6,000			0.0659
8	OREGON					
9	01APSV0041-AG PMP SRVC BP		2,083,375	4,725		
10	01APSV0041-BPA-AG PMP SRVC		-191,561			
11	01APSV041L-OR Pumping Serv		2,801,862	1,023		
12	01APSV041L-BPA-OR Pumping		-298,727			
13	01APSV041T-BPA- AGR PUMP SRV		-2,662			
14	01APSV041T AGR PUMP SRV-TOU		28,900	59		
15	01APSV041X-AG PMP SRVC		85,514	244		
16	01APSV41XL-OR Pump Srv no BPA		235,513	54		
17	01BPADEBIT-BPA ADJUST FEE		34,645			
18		113,183	5,924,955			0.0523
19	01COST0048-01LGSV0048	7,400	363,700			0.0491
20	01COSTS028 OR GEN SERV	297	16,271			0.0548
21	01GNSV0028 OR GEN SRV>30 kW		11,241	3		
22	01HABIT041-01APSV0041 AG PMP	5	256			0.0512
23	01LGSB0048-BPA-LG GEN		-34,625			
24	01LGSB0048-LG GEN		84,551	1		
25	01LNX00103-LINE EXT 80% G		29,317			
26	01LNX00109-REF/NREF ADV +		10,182			
27	01LNX00110-REF/NREF ADV +		165,779			
28	01LNX00310-LINE EXTENSION		9,946			
29	01PTOU0041-01APSV0041 AG PMP	588	28,667			0.0488
30	01RENEW041-01APSV0041 AG	96	5,031			0.0524
31	01SLX00005-KLAMATH FALLS		340,123			
32	01SLX00013-K FALLS IRG MI		16,183			
33	01SLX00014-K FALLS IRG MI		128			
34	01STDAY041-Daily Standard Offer	114	6,717			0.0589
35	01USBGV033-KLAMATH IRG TOU		-44			
36	01USBOF033-KLAMATH BASIN	38,584	1,818,716	628	61,439	0.0471
37	01USBOF033-BPA-KLAMATH		-159,573			
38	01USBON033-KLAMATH BASIN	48,112	2,141,154	1,359	35,403	0.0445
39	01USBON033-BPA-KLAMATH		-197,000			
40	01VIR33136-OR VOL INCENT USB	613	27,244	11	55,727	0.0444
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01VIR33136-BPA-OR VOL INCENT		-2,515			
2	01VIR41136-OR VOL INCENT AGRI		3,300	2		
3	01VIR41136-BPA-OR VOL INCENT		-297			
4	301461-IRR DEMAND CHG		200			
5	01USBGV033-IRG TOU W/O BPA	2,175	69,806	9	241,667	0.0321
6	IRRIGATION BPA BAL ACCT		228,908			
7	IRRIGATION UNBILLED	46	3,000			0.0652
8	01LNX00312-OR IRG LINE EXT		22,124			
9	01NMT33135-OR NET	39	1,757	2	19,500	0.0451
10	01NMT33135-BPA-OR NET		-163			
11	01NMT41135-BPA-NETMTR AG		1,050	3		
12	OR GAIN ON SALE OF ASSET		839			
13	OR Irrigation - BPA adjustment		21,670			
14	OR SB 408 RECOVERY		215,595			
15	OR SB 838 RECOVERY		168			
16	REV. ACCOUNTING ADJ.		-29,901			
17	UTAH					
18	08APSV0010-IRR & SOIL DRA	156,284	10,052,314	2,718	57,500	0.0643
19	08APSV10NS-Irg Soil Drain Pump	18,547	1,119,632	118	157,178	0.0604
20	08LNX00002-MTHLY 80% GUAR		594			
21	08LNX00004-ANNUAL 80%GUAR		9,058			
22	08LNX00014-80% MIN MNTHLY		1,746			
23	08LNX00017-ADV/REF&80%ANN		179,401			
24	08LNX00310-IRR 80% ANNUAL		12,103			
25	08LNX00312 UT IRG LINE EXT		8,075			
26	08NMT10135-UT IRR_SOIL DRNG	12	711	1	12,000	0.0593
27	REV. ACCOUNTING ADJ.		169,168			
28	UNBILLED REV - IRRIGATION	66	3,000			0.0455
29	WASHINGTON					
30	02APSV0040-WA AG PMP SRVC	140,895	11,481,265	4,848	29,063	0.0815
31	02APSV0040-BPA-WA AG PMP		-622,998			
32	02APSV040X-WA AG PMP SRVC	8,902	661,241	405	21,980	0.0743
33	02BPADEBIT-BPA ADJUST FEE		24,238			
34	02LNX00103-LINE EXT 80% G		4,534			
35	02LNX00105-CNTRCT $ MIN G		72			
36	02LNX00110-REF/NREF ADV +		159,591			
37	02LNX00310-IRG 80% ANN		1,429			
38	02LNX00311-LINE EXT 80%		841			
39	02LNX00312-WA IRG LINE EXT		18,935			
40	IRR DEMAND CHG ACCR		500			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	REV. ACCOUNTING ADJ.		-348,912			
2	WA - CHEHALIS DEFERRAL		-120,000			
3	IRRIGATION BPA BAL ACCT		3,846			
4	IRRIGATION UNBILLED	282	17,000			0.0603
5	WYOMING					
6	05APS00040-AG PUMPING SVC	18,704	1,406,349	638	29,317	0.0752
7	05LNX00110-REF/NREF ADV +		55,039			
8	05LNX00103-LINE EXT 80% G		8,033			
9	05LNX00310 WY IRG LINE EXT		330			
10	IRRIGATION UNBILLED	15	1,000			0.0667
11	REV ACCOUNTING ADJ		-233			
12	05APS00040-AG PUMPING SVC	51	3,477	1	51,000	0.0682
13	05LNX00103-LINE EXT 80% GTY		1,414			
14	05LNX00110-REF/NREF ADV +		18,102			
15	05LNX00312-WY IRRG LINE EXT		1,283			
16	09APSV0210-IRR & SOIL DRA	3,277	277,014	73	44,890	0.0845
17	LESS MULTIPLE BILLINGS			-724		
18						
19	TOTAL IRRIGATION SALES	1,187,406	93,961,381	23,079	51,450	0.0791
20						
21	PUBLIC STREET & HWY LIGHTING					
22	CALIFORNIA					
23	06CUSL053F-SPECIAL CUST O	1,455	208,491	116	12,543	0.1433
24	06CUSL058F-CUST OWND STR	242	38,789	23	10,522	0.1603
25	06HPSV0051-HI PRESSURE SO	697	183,229	78	8,936	0.2629
26	REV.ACCOUNTING ADJ.		-5,915			
27	UNBILLED REVENUE	48	9,000			0.1875
28	IDAHO					
29	07GNSV023S-ID TRAFFIC SIGNALS	165	17,308	25	6,600	0.1049
30	07SLCO0011-STR LGT CO-OWN	93	41,955	29	3,207	0.4511
31	07SLCU012E-ENGY STR	310	33,888	19	16,316	0.1093
32	07SLCU012F-FULL MNT STR	1,920	370,467	281	6,833	0.1930
33	07SLCU012P-PART MNT STR LGT	195	27,710	16	12,188	0.1421
34	UNBILLED REVENUE	41	7,000			0.1707
35	OREGON					
36	01COSL0052-STR LGT SRVC C	609	92,754	50	12,180	0.1523
37	01CUSL0053-CUS-OWNED MTRD	822	62,902	71	11,577	0.0765
38	01CUSL053E-STR LGT SVC	8,650	663,079	168	51,488	0.0767
39	01CUSL053F-STR LGT SRVC C	201	22,949	17	11,824	0.1142
40	01HPSV0051-HI PRESSURE SO	18,737	3,916,753	695	26,960	0.2090
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01LEDSL055-OR LED PILOT	5	1,395	4	1,250	0.2790
2	01MVSL0050-MERC VAPSTR LG	9,038	1,230,796	250	36,152	0.1362
3	01OALT014N-OUTD AR LGT NR	1	223	3	333	0.2230
4	01OALT014N-BPA-OUTD AR LGT		-5			
5	01OALT015N-OUTD AR LGT NR	15	2,363	6	2,500	0.1575
6	01OALTB15N-OR OUTD LGT NR	1	234	2	500	0.2340
7	01OALTB15N-W/BPA-OR OUTD		-5			
8	OR GAIN ON SALE OF ASSET		387			
9	OR SB 408 RECOVERY		40,424			
10	OR SB 838 RECOVERY		-1,215			
11	REV. ACCOUNTING ADJ.		-13,801			
12	UNBILLED REVENUE	-175	-13,000			0.0743
13	UTAH					
14	08CFR00012-STR LGTS (CONV		54			
15	08CFR00051-MTH FAC SRVCHG		4,529			
16	08CFR00062-STREET LIGHTS		79			
17	08OALT007N-SECURITY AR LG	22	5,694	13	1,692	0.2588
18	08TOSS015F-TRAFFIC SIG NM	1,007	90,508	123	8,187	0.0899
19	08SLCO0011-STR LGT CO-OWN	18,758	5,585,069	919	20,411	0.2977
20	08TOSS0015-TRAF & OTHER S	2,854	286,876	1,487	1,919	0.1005
21	08MONL0015-MTR OUTDONIGHT	862	65,995	59	14,610	0.0766
22	08SLCU012P-STR LGT CUST-O	5,488	677,415	239	22,962	0.1234
23	08SLCU012F-STR LGT CUST-O	2,251	306,573	113	19,920	0.1362
24	08SLCU012E-DECOR CUST-OWN	47,992	3,120,862	457	105,015	0.0650
25	08THIK0077-STR LIGHT SPEC	141	17,277	1	141,000	0.1225
26	REV. ACCOUNTING ADJ.		12,501			
27	UNBILLED REVENUE	-485	-55,000			0.1134
28	WASHINGTON					
29	02CFR00012-STR LGTS (CONV		90			
30	02COSL0052-WA STR LGT SRV	324	52,183	18	18,000	0.1611
31	02CUSL053F-WA STR LGT SRV	3,528	249,808	109	32,367	0.0708
32	02CUSL053M-WA STR LGT SRV	1,149	80,217	96	11,969	0.0698
33	02HPSV0051-WA HI PRESSURE	3,314	665,246	155	21,381	0.2007
34	02MVSL0057-WA MERC VAPSTR	1,964	241,205	41	47,902	0.1228
35	WA - CHEHALIS DEFERRAL		-30,000			
36	REV. ACCOUNTING ADJ.		-22,054			
37	UNBILLED REVENUE	-26	-9,000			0.3462
38	WYOMING					
39	05COSL0057-CO-OWND STR LG	290	58,992	18	16,111	0.2034
40	05CUSL058M-CUST OWND STR	81	5,140	11	7,364	0.0635
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05CUSL0E58-WY CUST OWND	1,079	67,909	30	35,967	0.0629
2	05CUSL0M58-CUST OWNED	45	3,449	4	11,250	0.0766
3	05HPSV0051-HI PRESSURE SO	4,973	1,025,677	158	31,475	0.2062
4	05MVS00053-MERCURY VAPOR	3,805	480,826	264	14,413	0.1264
5	05OALT015N-OUT AR LGT SR			1		
6	REV. ACCOUNTING ADJ.		-587			
7	UNBILLED REVENUE	-15	-1,000			0.0667
8	05OALT015N-OUTD AR LGT SR		3			
9	09MONL0213-WY MTR OUTDOOR	25	1,931	1	25,000	0.0772
10	09SLCO0211-STR LGT CO-OWN	1,481	406,275	48	30,854	0.2743
11	09SLCUP212-STR LGT CUST-O	77	11,288	9	8,556	0.1466
12	09TOSS0213-WY TRAF & OTH SIG	63	2,393	14	4,500	0.0380
13	UNBILLED REVENUE	217	63,000			0.2903
14	LESS MULTIPLE BILLINGS			-2,496		
15						
16	TOTAL PUBLIC STREET & HWY	144,334	20,409,578	3,745	38,540	0.1414
17						
18	OTHER SALES TO PUBLIC AUTH					
19	UTAH					
20	08GNSV0006-GEN SRVC-DISTR	2,188	150,625	4	547,000	0.0688
21	08GNSV0023-GEN SRVC-DISTR	38	3,533	3	12,667	0.0930
22	08GNSV009M-MANL HIGH VOLT	380,709	17,729,560	3	126,903,000	0.0466
23	08OALT007N-SECURITY AR LG	16	4,103	2	8,000	0.2564
24	08PRSV031M-BKUP MNT&SUPPL	19,899	1,135,234	1	19,899,000	0.0570
25	REV. ACCOUNTING ADJ.		325,774			
26	UNBILLED REVENUE	-4,357	-43,000			0.0099
27	LESS MULTIPLE BILLIINGS			-1		
28						
29	TOTAL OTHER SALES TO PUBLIC	398,493	19,305,829	12	33,207,750	0.0484
30						
31	FORFEITED DISCOUNTS					
32	CALIFORNIA					
33	Late Fees		313,339			
34	IDAHO					
35	Late Fees		416,071			
36	OREGON					
37	Late Fees		3,488,530			
38	UTAH					
39	Late Fees		2,983,753			
40	WASHINGTON					
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Late Fees		627,834			
2	WYOMING					
3	Late Fees		616,378			
4						
5	TOTAL FORFEITED DISCOUNTS		8,445,905			
6						
7	MISCELLANEOUS SERVICE REV					
8	CALIFORNIA					
9	06CFR00003-MTH MAINTENANC		1,454			
10	06CONN0300-CA RECONNECTIO		31,890			
11	06FCBUYOUT		14,091			
12	06RCHK0300-CA RET CHK CHR		13,488			
13	06TAMP0300-CA TAMP & UNAU		1,200			
14	06TEMP0300-CA TEMP SRVC C		2,155			
15	06XMTRTAMP-TAMPERING -		295			
16	Home Comfort		826			
17	IDAHO					
18	07CFR00001-MTH FAC SRVCHG		1,646			
19	07CONN0300-ID RECONNECTIO		48,340			
20	07RCHK0300-ID RET CHK CHR		37,120			
21	07TAMP0300		525			
22	07TEMP0014-TEMP SRVC CONN		10,880			
23	07XMTRTAMP-TAMPERING -		80			
24	Other		-2,730			
25	OREGON					
26	01CFR00001-MTH FACILITY S		84,712			
27	01CFR00003-MTH MAINTENANC		25,964			
28	01CFR00004-EMRGNCY ST&BY		25,247			
29	01CFR00005-INTERMTNT		42,247			
30	01CFR00013-MTH MISC CHRG		2,284			
31	01CFR00014-YR MISC CHRG		5			
32	01CONN0300-RECONNECTION C		341,110			
33	01CONTSERV-OR 3RD PARTY		9,815			
34	01ESSC0600 - ESS charges		3,180			
35	01FCBUYOUT-FAC CHG BUYOUT		302,961			
36	01MTRVR300-METR VERIF FEE		40			
37	01RCHK0300-RETURNED CHECK		319,040			
38	01TAMP0300-TAMP & UNAUTH		15,675			
39	01TEMP0300-TEMP SRVC CHRG		76,175			
40	01XMTRTAMP-TAMPERING -		3,287			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Other		-32,708			
2	TAMPERING FEE		75			
3	UTAH					
4	08CFR00013-MTH MISC CHRG		146,885			
5	08CFR00051-MTH FAC SRVCHG		93,501			
6	08CFR00052-ANN FAC SVCCHG		424			
7	08CFR00053-MTHLY MAINTFEE		16,913			
8	08CFR00063-MTH MISC CHARG		2,401			
9	08CFR00064-ANN MISC CHARG		6,660			
10	08CONN0300-RECONN&DISCONN		382,195			
11	08CONTSERV-3RD PARTY O/S		280,072			
12	08FCBUYOUT-FAC CHG BUYOUT		563,871			
13	08METR0300-UT FEE MTR TES		60			
14	08NCON0300-UT FEE NRES RE		6,355			
15	08RCHK0300-UT RET CHK CHR		482,936			
16	08RCON0001-CONNECT FEE		1,507,930			
17	08TAMP0300-TAMPERING&UNAU		14,850			
18	08TEMP0014-TEMP SRVC CONN		304,125			
19	08XMTRTAMP-TAMPERING -		2,534			
20	Energy Finanswer new Com		19,119			
21	Other		3,692			
22	08VISIT300 - UT Visit, Service Ca		235,210			
23	WASHINGTON					
24	02CFR00003-MTH MAINTENANC		1,320			
25	02CFR00004-EMRGNCY ST&BY		5,901			
26	02CFR00005-INTERMTNT SRVC		4,302			
27	02CONN0300-WA RECONNECTIO		75,420			
28	02RCHK0300-WA RET CHK CHR		63,940			
29	02TAMP0300-WA TAMP & UNAU		3,075			
30	02TEMP0300-WA TEMP SRVC C		17,625			
31	02XMTRTAMP-TAMPERING -		637			
32	Energy Finanswer new Com		1,323			
33	Home Comfort		2,493			
34	Other		-654			
35	WYOMING					
36	05CFR00003-MTH MAINTENANC		1,768			
37	05CFR00004-EMRGNCY ST&BY		18,953			
38	05CFR00005-INTERMTNT SRVC		10,263			
39	05CFR00013-MTH MISC CHRG		3,186			
40	05CONN0300-WY RECONNECTIO		69,740			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05FCBUYOUT - FAC CHG BUYOUT		137,997			
2	05RCHK0300-WY RET CHK CHR		69,540			
3	05SERV0300-WY SRVC CALLS		120			
4	05TAMP0300		525			
5	05TEMP0300-WY TEMP SRVC C		31,450			
6	Other		1,208			
7	05XMTRTAMP-TAMPERING -		175			
8	09CFR00005-INTERMTNT SRVC		339			
9	05CONN0300-WY RECONNECTIO		11,560			
10	05FCBUYOUT - FAC CHG BUYOUT		202,126			
11	05RCHK0300-WY RET CHK CHR		12,300			
12	05TEMP0300-WY TEMP SRVC C		1,475			
13	09CFR00001 MTH FAC SRV CHG		5,067			
14	09CFR00014-YR MISC CHRG		3			
15	Energy Finanswer 12,000		228			
16						
17	TOTAL MISC SERVICE REV		6,203,507			
18						
19	SALES OF WATER AND WTR PWR					
20	UTAH		89,567			
21	WYOMING		5,306			
22						
23	TOTAL WATER AND WATER PWR		94,873			
24						
25	RENT FROM ELEC PROPERTIES					
26	CALIFORNIA					
27	06CFR00006-MTH RNTAL CHRG		1,659			
28	RENT REVENUE-HYDRO		200			
29	RENT REVENUE-TRANSMISSION		55			
30	Rent Revenue - Subleases		16,879			
31	Joint use		547,446			
32	IDAHO					
33	07CFR00009-YR LSE CHRG-EQ		794			
34	07INVCHG00-INVEST MNT CHG		182			
35	07POLE0075-STEEL POLES US		275			
36	RENT REVENUE-HYDRO		68,732			
37	RENT REV-TRANSMISS		400			
38	Rent Revenue - Subleases		2,216			
39	Joint use		194,566			
40	OREGON					
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01CFR00006-MTH RNTAL CHRG		657,955			
2	01XTRN0013-RNT/LSE L&PRO		52,993			
3	RENTS - COMMON		465,700			
4	Rents - Non Common		125			
5	MCI FOGWIRE REVENUE		3,352,504			
6	Rent Revenue - Subleases		345,368			
7	RENT REVENUE-CSS NON FLT		-52,993			
8	RENT REVENUE-HYDRO		32,722			
9	RENT REV-TRANSMISS		239,908			
10	RENT REV-DISTRIBUT		56,572			
11	RENT REV-GEN(COMM)		43,100			
12	Joint use		4,453,879			
13	UTAH					
14	08CFR00056-MTH EQUIP RENT		33			
15	08CFR00058-MTH EQUIP LEAS		750,028			
16	08INVCHG0N-INVEST MNT CHG		4,447			
17	08INVCHG0R-INVEST MNT CHG		271			
18	08LOOP014N-TEMP SERV CONN		78			
19	08POLE0075-STEEL POLES US		56,960			
20	RENTS - COMMON		-1,736			
21	Rents - Non Common		16,440			
22	RENT REVENUE-STEAM		102,122			
23	RENT REVENUE-HYDRO		96,718			
24	RENT REV-TRANSMISS		994,104			
25	RENT REV-DISTRIBUT		428,828			
26	RENT REV-GEN(COMM)		-5,374			
27	Rent Revenue - Subleases		2,556,839			
28	Affiliated Rent Revenue		11,057			
29	Joint use		2,227,437			
30	WASHINGTON					
31	02CFR00001-MTH FACILITY S		2,104			
32	02CFR00006-MTH RNTAL CHRG		30,308			
33	RENT REVENUE-HYDRO		608,308			
34	RENT REV-DISTRIBUT		18,876			
35	RENT REV-GEN(COMM)		32,674			
36	RENT REV-TRANSMISS		16,089			
37	Rent Revenue - Subleases		46,811			
38	Joint use		1,057,961			
39	WYOMING					
40	05CFR00001-MTH FACILITY S		11,524			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	05CFR00006-MTH RNTAL CHRG		2,482			
2	RENT REVENUE-STEAM		161,219			
3	RENT REV-HYDRO		39,304			
4	RENT REV-TRANSMISS		250			
5	RENT REV-DISTRIBUT		21,502			
6	RENT REV-GEN(COMM)		8,726			
7	Rent Revenue - Subleases		17,716			
8	Joint use		358,139			
9	09POLE0075-STEEL POLES US		19,230			
10	RENT REVENUE-STEAM		7,710			
11						
12	TOTAL RENT FROM ELEC PROP		20,180,422			
13						
14	WIND BASED ANCILLARY SVC		8,045,284			
15	OTHER ELEC ESTIMATE		83,442			
16	RENEWABLE ENERGY CREDIT		24,633,026			
17	NON-WHEELING SYSTEM		9,117,901			
18	Other Elec (exclud Wheel)		1,600			
19	RENEWABLE ENGY CR AMORT		12,591,648			
20	CALIFORNIA					
21	ALL BLUE SKY RES		31,968			
22	3RD PARTY TRANS O&M		47,850			
23	DSM REV-CA SBC OFF		1,785,661			
24	Fish, Wildlife, Recr		7,281			
25	IDAHO					
26	ALL BLUE SKY RES		41,542			
27	DSM REV-ID SBC		5,356,975			
28	3RD PARTY TRANS O&M		98,043			
29	OREGON					
30	ALL BLUE SKY RES		373,485			
31	DSM REV-OR ECC		22,316,839			
32	3RD PARTY TRANS		193,660			
33	Other Elec (exclud Wheel)		1,244,655			
34	Other Elec DSR carry chrg		169,156			
35	UTAH					
36	ALL BLUE SKY RES		1,818,926			
37	08XTRN0011-SALE ORDERS		8,602			
38	M&S INVENTORY REVENUE		264,638			
39	ELEC INC-OTHR		249,497			
40	FLYASH SALES		2,237,553			
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	3RD PARTY TRANS		287,415			
2	DSM REV-UT SBC OFFSET		49,303,455			
3	Fish, Wildlife, Recr		2,380			
4	WASHINGTON					
5	ALL BLUE SKY RES		99,779			
6	3RD PARTY TRANS		3,370			
7	DSM REV-WA SBC		8,883,682			
8	Fish, Wildlife, Recr		6,483			
9	Wash Colstrip 3		-52,188			
10	WYOMING					
11	ALL BLUE SKY RES		116,944			
12	M&S INVENTORY REVENUE		9,420			
13	05XTRN0011-SALES ORDERS INV		964			
14	ELEC INC-OTHER		17			
15	FLYASH SALES		874,779			
16	WY Regulatory Recovery Fee		227,739			
17	3RD PARTY TRANS		53,819			
18	DSM REVENUE-WY SBC-CAT 1		1,787,088			
19	DSM REVENUE-WY SBC-CAT 2		897,775			
20	DSM REVENUE-WY SBC-CAT 3		1,179,265			
21	FLYASH SALES		22,732			
22	DSM REVENUE-WY SBC-CAT 1		-412			
23	DSM REVENUE-WY SBC-CAT 2		606			
24	DSM REVENUE-WY SBC-CAT 3		24,201			
25						
26	TOTAL OTHER ELEC REVENUE		154,448,545			
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	54,246,323	4,091,383,354	1,742,220	31,136	0.0754
42	Total Unbilled Rev.(See Instr. 6)	60,543	31,358,500	0	0	0.5180
43	TOTAL	54,306,866	4,122,741,854	1,742,220	31,171	0.0759

Schedule Page: 304.15 Line No.: 18 Column: a

01COST0041 - 01APSV0041 - 01APSV041X AG PMP

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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 Corporation	RQ	T-12	18	17	16
3	Deaver, Town of	RQ	T-4	0.2	0.1	0.1
4	Helper City	RQ	T-6	1	1	1
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 Corporation	RQ	T-12	25	12	11
10	Accrual	RQ	NA	NA	NA	NA
11						
12	Nonrequirement Sales					
13	Arizona Public Service Company	SF	T-12	NA	NA	NA
14	Avista Corporation	SF	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 Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
95,952	2,060,955	2,329,498	262,710	4,653,163	2
799	12,695	14,318		27,013	3
6,096	116,457	107,843		224,300	4
3,822	71,502	67,607		139,109	5
1,139	18,842	19,846		38,688	6
9,149	138,555	159,374		297,929	7
11,076		1,012,660	4,732	1,017,392	8
71,652	1,417,928	1,730,495	161,951	3,310,374	9
2,763			-9,544	-9,544	10
					11
					12
79,287		2,739,683		2,739,683	13
51,218		1,379,006		1,379,006	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Avista Corporation	SF	T-13	NA	NA	NA
2	BNP Paribas Energy Trading GP	SF	T-12	NA	NA	NA
3	BP Energy Company	SF	T-12	NA	NA	NA
4	Barclays Bank PLC	AD	T-12	NA	NA	NA
5	Barclays Bank PLC	SF	T-12	NA	NA	NA
6	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
7	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
8	Black Hills Power, Inc.	LF	441	50	55	50
9	Black Hills Power, Inc.	OS	T-12	NA	NA	NA
10	Black Hills Power, Inc.	SF	T-11	NA	NA	NA
11	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
12	Black Hills Wyoming, Inc.	SF	T-12	NA	NA	NA
13	Bonneville Power Administration	AD	519	NA	NA	NA
14	Bonneville Power Administration	AD	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
64			2,016	2,016	1
8,800		404,800		404,800	2
179,960		5,079,222		5,079,222	3
9			722	722	4
312,230		13,946,237		13,946,237	5
51			1,257	1,257	6
24,270		847,882		847,882	7
330,354	7,374,306	5,131,102		12,505,408	8
760		24,145		24,145	9
3			156	156	10
220,717		5,694,096		5,694,096	11
67		2,305		2,305	12
			144,770	144,770	13
-938			-30,147	-30,147	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	519	NA	NA	NA
4	Bonneville Power Administration	SF	T-11	NA	NA	NA
5	Bonneville Power Administration	SF	T-12	NA	NA	NA
6	Bonneville Power Administration	SF	T-13	NA	NA	NA
7	British Columbia Transmission Corp.	SF	T-13	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	SF	T-11	NA	NA	NA
12	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
13	Citigroup Energy Inc.	AD	T-12	NA	NA	NA
14	Citigroup Energy Inc.	IF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,199			55,794	55,794	1
14,629			396,867	396,867	2
40,125		2,924,711		2,924,711	3
1,374			39,310	39,310	4
96,686		2,139,570		2,139,570	5
110			2,916	2,916	6
2			68	68	7
275			27,531	27,531	8
774,061		20,312,363		20,312,363	9
728			17,320	17,320	10
9,225			241,297	241,297	11
708,776		23,700,779		23,700,779	12
835			33,424	33,424	13
29,939		2,047,828		2,047,828	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Citigroup Energy Inc.	SF	T-12	NA	NA	NA
2	City of Anaheim	SF	T-12	NA	NA	NA
3	City of Burbank	SF	T-12	NA	NA	NA
4	City of Glendale	SF	T-12	NA	NA	NA
5	City of Hurricane	LF	T-12	NA	NA	NA
6	City of Redding	SF	T-12	NA	NA	NA
7	City of Santa Clara	SF	T-12	NA	NA	NA
8	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
9	Colorado River Commission of Nevada	SF	T-12	NA	NA	NA
10	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
11	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
12	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
13	DB Energy Trading LLC	AD	T-12	NA	NA	NA
14	DB Energy Trading LLC	SF	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 Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,993,699		64,910,506		64,910,506	1
14,614		487,542		487,542	2
53,578		1,440,678		1,440,678	3
11,800		378,856		378,856	4
216		16,200		16,200	5
27,169		636,792		636,792	6
5,269		38,805		38,805	7
508		14,205		14,205	8
56,357		1,990,756		1,990,756	9
5,106			142,791	142,791	10
35			1,209	1,209	11
544,922		17,214,738		17,214,738	12
10			224	224	13
325,446		11,136,767		11,136,767	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Deseret Generation & Transmission Coop.	SF	T-11	NA	NA	NA
2	EDF Trading North America, LLC	SF	T-11	NA	NA	NA
3	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
4	El Paso Electric Company	SF	T-12	NA	NA	NA
5	Eugene Water & Electric Board	SF	T-11	NA	NA	NA
6	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
7	Exelon Power Team	SF	T-12	NA	NA	NA
8	Gila River Power LLC	SF	T-12	NA	NA	NA
9	Iberdrola Renewables, Inc.	LF	T-11	NA	NA	NA
10	Iberdrola Renewables, Inc.	SF	T-11	NA	NA	NA
11	Iberdrola Renewables, Inc.	SF	T-12	NA	NA	NA
12	Idaho Power Company	LF	T-11	NA	NA	NA
13	Idaho Power Company	SF	T-11	NA	NA	NA
14	Idaho Power Company	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
43			748	748	1
32			1,180	1,180	2
258,033		8,602,210		8,602,210	3
38,784		1,105,489		1,105,489	4
500			16,188	16,188	5
15,419		379,325		379,325	6
4,800		167,500		167,500	7
31,276		862,394		862,394	8
3,451			88,838	88,838	9
431			9,554	9,554	10
336,117		9,030,532		9,030,532	11
397			12,879	12,879	12
3,998			126,259	126,259	13
76,358		1,625,418		1,625,418	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Idaho Power Company	SF	T-13	NA	NA	NA
2	Intermountain Renewable Power, LLC	LF	T-11	NA	NA	NA
3	J. Aron & Company	SF	T-12	NA	NA	NA
4	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
5	J.P. Morgan Ventures Energy Corporation	SF	T-12	NA	NA	NA
6	Los Angeles Dept. of Water & Power	LU	301	NA	NA	NA
7	Los Angeles Dept. of Water & Power	SF	T-11	NA	NA	NA
8	Los Angeles Dept. of Water & Power	SF	T-12	NA	NA	NA
9	Macquarie Energy LLC	SF	T-11	NA	NA	NA
10	Macquarie Energy LLC	SF	T-12	NA	NA	NA
11	Modesto Irrigation District	SF	T-12	NA	NA	NA
12	Morgan Stanley Capital Group, Inc.	AD	T-12	NA	NA	NA
13	Morgan Stanley Capital Group, Inc.	SF	T-11	NA	NA	NA
14	Morgan Stanley Capital Group, Inc.	SF	T-12	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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
218			6,526	6,526	1
2,235			58,346	58,346	2
135,999		4,826,746		4,826,746	3
3,921			93,915	93,915	4
101,853		2,425,797		2,425,797	5
571,555		27,759,598		27,759,598	6
5,312			126,308	126,308	7
56,891		1,171,501		1,171,501	8
2			70	70	9
164,735		4,548,393		4,548,393	10
45,079		1,509,203		1,509,203	11
704			28,228	28,228	12
11,322			294,514	294,514	13
1,922,634		58,345,518		58,345,518	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Municipal Energy Agency of Nebraska	SF	T-11	NA	NA	NA
2	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
3	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
4	Nevada Power Company	IF	T-12	NA	NA	NA
5	Nevada Power Company	SF	T-11	NA	NA	NA
6	NextEra Energy Power Marketing, LLC	AD	T-11	NA	NA	NA
7	NextEra Energy Power Marketing, LLC	LF	T-11	NA	NA	NA
8	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
9	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
10	NorthWestern Corporation	SF	T-13	NA	NA	NA
11	Northern California Power Agency	SF	T-12	NA	NA	NA
12	PPL EnergyPlus, LLC	SF	T-12	NA	NA	NA
13	PPL Montana, LLC	SF	T-11	NA	NA	NA
14	Pacific Gas & Electric Company	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 Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4			79	79	1
113,080		2,678,949		2,678,949	2
52			1,028	1,028	3
916,116		25,051,098		25,051,098	4
5			179	179	5
529			17,400	17,400	6
10,107			255,278	255,278	7
23			5,499	5,499	8
170		7,395		7,395	9
126			3,417	3,417	10
6,526		132,426		132,426	11
83,110		2,018,910		2,018,910	12
640			20,320	20,320	13
287,202		6,784,113		6,784,113	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Pacific Gas & Electric Company	SF	T-12	NA	NA	NA
2	Pacific Northwest Generating Coop.	SF	T-12	NA	NA	NA
3	Pacific Summit Energy LLC	SF	T-12	NA	NA	NA
4	Portland General Electric Company	SF	T-11	NA	NA	NA
5	Portland General Electric Company	SF	T-12	NA	NA	NA
6	Portland General Electric Company	SF	T-13	NA	NA	NA
7	Powerex Corporation	AD	T-11	NA	NA	NA
8	Powerex Corporation	LF	T-11	NA	NA	NA
9	Powerex Corporation	SF	T-11	NA	NA	NA
10	Powerex Corporation	SF	T-11	NA	NA	NA
11	Powerex Corporation	SF	T-12	NA	NA	NA
12	Public Service Company of Colorado	AD	320	NA	NA	NA
13	Public Service Company of Colorado	AD	T-12	NA	NA	NA
14	Public Service Company of Colorado	LF	320	36	36	29
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
367,445		9,847,770		9,847,770	1
195		4,070		4,070	2
890		23,140		23,140	3
147			2,443	2,443	4
85,842		2,001,528		2,001,528	5
91			2,214	2,214	6
21			585	585	7
26,044			690,665	690,665	8
19,441			516,834	516,834	9
29			782	782	10
411,678		10,031,560		10,031,560	11
			340,579	340,579	12
2			45	45	13
236,495	4,315,680	13,733,635		18,049,315	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Public Service Company of Colorado	SF	T-11	NA	NA	NA
2	Public Service Company of Colorado	SF	T-12	NA	NA	NA
3	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
4	PUD #1 of Douglas County	SF	T-12	NA	NA	NA
5	PUD #1 of Douglas County	SF	T-13	NA	NA	NA
6	PUD #1 of Snohomish County	SF	T-12	NA	NA	NA
7	PUD #2 of Grant County	SF	T-12	NA	NA	NA
8	PUD #2 of Grant County	SF	T-13	NA	NA	NA
9	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
10	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
11	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
12	Rainbow Energy Marketing Corporation	SF	T-12	NA	NA	NA
13	Sacramento Municipal Utility District	AD	250	NA	NA	NA
14	Sacramento Municipal Utility District	LF	250	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
9			53	53	1
74,122		2,176,203		2,176,203	2
187,062		5,774,257		5,774,257	3
1,870		48,950		48,950	4
2			60	60	5
20,750		555,820		555,820	6
16,556		406,638		406,638	7
22			612	612	8
78,449		1,903,705		1,903,705	9
57			1,512	1,512	10
1,465			38,320	38,320	11
19,136		577,938		577,938	12
			-66,136	-66,136	13
569,382		13,818,901		13,818,901	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
2	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
3	Salt River Project	SF	T-12	NA	NA	NA
4	San Diego Gas & Electric Company	AD	T-12	NA	NA	NA
5	San Diego Gas & Electric Company	SF	T-12	NA	NA	NA
6	Seattle City Light	LF	T-11	NA	NA	NA
7	Seattle City Light	SF	T-12	NA	NA	NA
8	Sempra Energy Trading LLC	AD	T-12	NA	NA	NA
9	Sempra Generation	SF	T-12	NA	NA	NA
10	Shell Energy North America (US), L.P.	OS	T-12	NA	NA	NA
11	Shell Energy North America (US), L.P.	SF	T-11	NA	NA	NA
12	Shell Energy North America (US), L.P.	SF	T-12	NA	NA	NA
13	Sierra Pacific Power Company	LF	T-11	NA	NA	NA
14	Sierra Pacific Power Company	SF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
46,827		1,324,951		1,324,951	1
31			280	280	2
256,185		7,490,868		7,490,868	3
125			1,141	1,141	4
2,398		60,651		60,651	5
2,838			64,989	64,989	6
12,747		265,570		265,570	7
24			1,158	1,158	8
74,200		2,074,994		2,074,994	9
500		14,000		14,000	10
181			4,767	4,767	11
684,397		28,174,513		28,174,513	12
956			25,359	25,359	13
275			7,355	7,355	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

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	Sierra Pacific Power Company	SF	T-13	NA	NA	NA
2	Southern California Edison Company	IF	T-12	NA	NA	NA
3	Southern California Edison Company	SF	T-11	NA	NA	NA
4	Southern California Edison Company	SF	T-11	NA	NA	NA
5	Southern California Edison Company	SF	T-12	NA	NA	NA
6	Southwestern Public Service Company	SF	T-12	NA	NA	NA
7	Tacoma Power	SF	T-12	NA	NA	NA
8	Tenaska Power Services Co.	SF	T-11	NA	NA	NA
9	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
10	TransAlta Energy Marketing (U.S.) Inc.	SF	T-11	NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	SF	T-12	NA	NA	NA
12	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
13	Tri-State Gen. & Trans.	SF	T-11	NA	NA	NA
14	Tri-State Gen. & Trans.	SF	T-12	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
269			7,749	7,749	1
327,600		9,272,844		9,272,844	2
14,849			374,868	374,868	3
20			545	545	4
66,878		2,663,971		2,663,971	5
171,928		5,294,349		5,294,349	6
9,384		244,281		244,281	7
847			16,475	16,475	8
7,274		223,362		223,362	9
1,638			50,339	50,339	10
168,781		4,308,301		4,308,301	11
2,000		65,700		65,700	12
1,102			34,933	34,933	13
157,557		4,470,695		4,470,695	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

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	Tucson Electric Power Company	SF	T-12	NA	NA	NA
2	Turlock Irrigation District	SF	T-12	NA	NA	NA
3	UNS Electric, Inc.	SF	T-12	NA	NA	NA
4	Utah Associated Municipal Power Systems	OS	T-12	NA	NA	NA
5	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
6	Utah Municipal Power Agency	LF	433	34	34	34
7	Utah Municipal Power Agency	SF	T-3	NA	NA	NA
8	Western Area Power Administration	AD	T-11	NA	NA	NA
9	Western Area Power Administration	LF	T-11	NA	NA	NA
10	Western Area Power Administration	SF	T-11	NA	NA	NA
11	Western Area Power Administration	SF	T-12	NA	NA	NA
12	Netting - Bookouts	AD	NA	NA	NA	NA
13	Netting - Trading	AD	NA	NA	NA	NA
14	Accrual	NA	NA	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
259,218		8,082,228		8,082,228	1
11,206		296,280		296,280	2
346,463		10,013,028		10,013,028	3
7,765		211,034		211,034	4
11,437		309,527		309,527	5
194,954	4,396,200	4,530,731		8,926,931	6
8,080		69,360		69,360	7
63			4,995	4,995	8
515			14,819	14,819	9
8,218			237,133	237,133	10
161,327		6,139,837		6,139,837	11
-5,703,900			-167,137,516	-167,137,516	12
			-11,500,014	-11,500,014	13
-4,444			-151,741	-151,741	14
202,448	3,836,934	5,441,641	419,849	9,698,424	
10,564,249	16,086,186	500,177,279	-174,169,520	342,093,945	
10,766,697	**19,923,120**	**505,618,920**	**-173,749,671**	**351,792,369**	

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

Schedule Page: 310 Line No.: 6 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “NAVAJO TRIBAL UTIL AUTH (MEXICAN HAT)” ON PAGES 310 – 311: Complete name is Navajo Tribal Utility Authority (Mexican Hat).

Schedule Page: 310 Line No.: 7 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “NAVAJO TRIBAL UTIL AUTH (RED MESA)” ON PAGES 310–311: Complete name is Navajo Tribal Utility Authority (Red Mesa).

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

Schedule Page: 310 Line No.: 9 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: 310.1 Line No.: 1 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: j
Transmission Losses

Schedule Page: 310.1 Line No.: 8 Column: b
Black Hills Power, Inc. - FERC 441 - Contract termination date: December 31, 2023.

Schedule Page: 310.1 Line No.: 9 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.1 Line No.: 10 Column: j
Transmission Losses

Schedule Page: 310.1 Line No.: 13 Column: b
Settlement Adjustment.

Schedule Page: 310.1 Line No.: 13 Column: j
Settlement Adjustment

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, 5th revised R.S. 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 (1st revised S.A. 179)] - Contract termination date: September 30, 2025 and (S.A. 656) - Contract termination date: August 31, 2030.

Schedule Page: 310.2 Line No.: 2 Column: j
Transmission Losses

Schedule Page: 310.2 Line No.: 4 Column: j
Transmission Losses

Schedule Page: 310.2 Line No.: 6 Column: j

Reserve Share

Schedule Page: 310.2 Line No.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “BRITISH COLUMBIA TRANSMISSION CORP.” ON PAGES 310–311: Complete name is British Columbia Transmission Corporation.

Schedule Page: 310.2 Line No.: 7 Column: j

Reserve Share

Schedule Page: 310.2 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “CALIFORNIA INDEPENDENT SYSTEM OPERATOR” ON PAGES 310–311: Complete name is California Independent System Operator Corporation.

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: j

Transmission Losses

Schedule Page: 310.2 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.2 Line No.: 13 Column: j

Settlement Adjustment

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

City of Hurricane - FERC T-12 - Contract termination date: August 31, 2007.

Schedule Page: 310.3 Line No.: 10 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “CONSTELLATION ENERGY COMMODITIES GROUP” ON PAGES 310–311: Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 310.3 Line No.: 10 Column: j

Transmission Losses

Schedule Page: 310.3 Line No.: 11 Column: j

Unauthorized use charges

Schedule Page: 310.3 Line No.: 13 Column: b

Settlement Adjustment.

Schedule Page: 310.3 Line No.: 13 Column: j

Settlement Adjustment

Schedule Page: 310.4 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “DESERET GENERATION & TRANSMISSION COOP.” ON PAGES 310–311: Complete name is Deseret Generation and Transmission Cooperative.

Schedule Page: 310.4 Line No.: 1 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 5 Column: j

Transmission Losses

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

Iberdrola Renewables, Inc. - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th revised S.A. 279)] - Contract termination date: April 30, 2014.

Schedule Page: 310.4 Line No.: 9 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 10 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 12 Column: b

Idaho Power Company - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th revised S.A. 212)] - Contract termination date: May 31, 2014.

Schedule Page: 310.4 Line No.: 12 Column: j

Transmission Losses

Schedule Page: 310.4 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 1 Column: j

Reserve Share

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

Intermountain Renewable Power, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (S.A. 568)] - Contract termination date: April 30, 2029.

Schedule Page: 310.5 Line No.: 2 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 4 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 6 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “LOS ANGELES DEPT. OF WATER & POWER” ON PAGES 310–311: Complete name is Los Angeles Department of Water and Power.

Schedule Page: 310.5 Line No.: 7 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 9 Column: j

Transmission Losses

Schedule Page: 310.5 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 310.5 Line No.: 12 Column: j

Settlement Adjustment

Schedule Page: 310.5 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.6 Line No.: 1 Column: j

Transmission Losses

Schedule Page: 310.6 Line No.: 3 Column: j

Reserve Share

Schedule Page: 310.6 Line No.: 5 Column: j

Transmission Losses

Schedule Page: 310.6 Line No.: 6 Column: b

Settlement Adjustment.

Schedule Page: 310.6 Line No.: 6 Column: j

Settlement Adjustment

Schedule Page: 310.6 Line No.: 7 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: 310.6 Line No.: 7 Column: j

Transmission Losses

Schedule Page: 310.6 Line No.: 8 Column: j

Unauthorized use charges

Schedule Page: 310.6 Line No.: 10 Column: j

Reserve Share

Schedule Page: 310.6 Line No.: 13 Column: j

Transmission Losses

Schedule Page: 310.7 Line No.: 2 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PACIFIC NORTHWEST GENERATING COOP.” ON PAGES 310–311: Complete name is Pacific Northwest Generating Cooperative, Inc.

Schedule Page: 310.7 Line No.: 4 Column: j
Transmission Losses

Schedule Page: 310.7 Line No.: 6 Column: j
Reserve Share

Schedule Page: 310.7 Line No.: 7 Column: b
Settlement Adjustment.

Schedule Page: 310.7 Line No.: 7 Column: j
Settlement Adjustment

Schedule Page: 310.7 Line No.: 8 Column: b
Powerex Corporation - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th revised S.A. 169)] - Contract termination date: October 31, 2020.

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.: 10 Column: j
Unauthorized use charges

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.: 13 Column: b
Settlement Adjustment.

Schedule Page: 310.7 Line No.: 13 Column: j
Settlement Adjustment

Schedule Page: 310.7 Line No.: 14 Column: b
Public Service Company of Colorado - FERC 320 - Contract termination date: December 31, 2011.

Schedule Page: 310.8 Line No.: 1 Column: j
Transmission Losses

Schedule Page: 310.8 Line No.: 4 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF DOUGLAS COUNTY” ON PAGES 310–311: Complete name is Public Utility District No. 1 of Douglas County.

Schedule Page: 310.8 Line No.: 5 Column: j
Reserve Share

Schedule Page: 310.8 Line No.: 6 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF SNOHOMISH COUNTY” ON PAGES 310–311: Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 310.8 Line No.: 7 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #2 OF GRANT COUNTY” ON PAGES 310–311: Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 310.8 Line No.: 8 Column: j
Reserve Share

Schedule Page: 310.8 Line No.: 10 Column: j
Reserve Share

Schedule Page: 310.8 Line No.: 11 Column: j
Transmission Losses

Schedule Page: 310.8 Line No.: 13 Column: b
Settlement Adjustment.

Schedule Page: 310.8 Line No.: 13 Column: j
Settlement Adjustment

Schedule Page: 310.8 Line No.: 14 Column: b
Sacramento Municipal Utility District - FERC 250 - Contract termination date: December 31, 2014.

Schedule Page: 310.9 Line No.: 2 Column: j
Reserve Share

Schedule Page: 310.9 Line No.: 4 Column: b
Settlement Adjustment.

Schedule Page: 310.9 Line No.: 4 Column: j
Settlement Adjustment

Schedule Page: 310.9 Line No.: 6 Column: b
Seattle City Light - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (7th revised S.A. 289)] - Contract termination date: October 31, 2014.

Schedule Page: 310.9 Line No.: 6 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.: 10 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.9 Line No.: 11 Column: j
Transmission Losses

Schedule Page: 310.9 Line No.: 13 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: 310.9 Line No.: 13 Column: j
Transmission Losses

Schedule Page: 310.9 Line No.: 14 Column: j
Transmission Losses

Schedule Page: 310.10 Line No.: 1 Column: j
Reserve Share

Schedule Page: 310.10 Line No.: 3 Column: j
Transmission Losses

Schedule Page: 310.10 Line No.: 4 Column: j
Unauthorized use charges

Schedule Page: 310.10 Line No.: 8 Column: j
Transmission Losses

Schedule Page: 310.10 Line No.: 10 Column: j
Transmission Losses

Schedule Page: 310.10 Line No.: 13 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “TRI-STATE GEN. & TRANS.” ON PAGES 310–311: Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 310.10 Line No.: 13 Column: j
Transmission Losses

Schedule Page: 310.11 Line No.: 4 Column: b
Secondary, Economy and/or non-firm sales, including some hourly firm transactions.

Schedule Page: 310.11 Line No.: 6 Column: b
Utah Municipal Power Agency - FERC 433 - Contract termination date: June 30, 2017.

Schedule Page: 310.11 Line No.: 8 Column: b
Settlement Adjustment.

Schedule Page: 310.11 Line No.: 8 Column: j
Settlement Adjustment

Schedule Page: 310.11 Line No.: 9 Column: b
Western Area Power Administration - FERC R.S. 664 [Purchase of Capacity in the 230kV Casper-Dave Johnston Transmission Line - Use of transmission service during times when Western's capacity is de-rated] – Contract termination date: 50 years after commercial

operation of the transmission line.

Schedule Page: 310.11 Line No.: 9 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 10 Column: j

Transmission Losses

Schedule Page: 310.11 Line No.: 12 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.11 Line No.: 13 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.11 Line No.: 14 Column: j

Represents the difference between actual non-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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	19,391,612	20,107,030
5	(501) Fuel	722,758,588	669,641,923
6	(502) Steam Expenses	38,138,103	38,472,021
7	(503) Steam from Other Sources	3,583,830	3,655,727
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	4,190,528	4,285,137
10	(506) Miscellaneous Steam Power Expenses	52,707,159	48,042,874
11	(507) Rents	277,654	338,685
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	841,047,474	784,543,397
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,365,300	6,462,258
16	(511) Maintenance of Structures	23,596,390	25,480,955
17	(512) Maintenance of Boiler Plant	109,128,194	112,922,881
18	(513) Maintenance of Electric Plant	39,898,808	38,934,338
19	(514) Maintenance of Miscellaneous Steam Plant	13,319,308	12,066,167
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	192,308,000	195,866,599
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,033,355,474	980,409,996
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	3,787,003	3,825,666
45	(536) Water for Power	257,504	212,409
46	(537) Hydraulic Expenses	3,696,681	3,449,509
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	21,669,423	20,295,293
49	(540) Rents	-404,504	117,398
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	29,006,107	27,900,275
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,891	469
54	(542) Maintenance of Structures	1,030,119	1,430,392
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,430,112	1,959,700
56	(544) Maintenance of Electric Plant	2,553,749	1,635,171
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,961,681	2,654,790
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,977,552	7,680,522
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	37,983,659	35,580,797

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	429,811	358,628
63	(547) Fuel	367,320,902	432,620,733
64	(548) Generation Expenses	15,368,434	14,638,002
65	(549) Miscellaneous Other Power Generation Expenses	21,289,631	18,701,556
66	(550) Rents	4,253,868	3,558,679
67	TOTAL Operation (Enter Total of lines 62 thru 66)	408,662,646	469,877,598
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,938,948	1,240,594
71	(553) Maintenance of Generating and Electric Plant	10,918,597	8,996,404
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,783,736	2,196,699
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	18,641,281	12,433,697
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	427,303,927	482,311,295
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	398,261,268	380,007,678
77	(556) System Control and Load Dispatching	1,744,114	877,454
78	(557) Other Expenses	60,776,842	63,870,496
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	460,782,224	444,755,628
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,959,425,284	1,943,057,716
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,689,657	5,041,115
84	(561) Load Dispatching		650,305
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,794,035	7,847,328
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	984,307	816,883
90	(561.6) Transmission Service Studies	206,982	83,476
91	(561.7) Generation Interconnection Studies	763,228	938,904
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,647,395	2,124,825
94	(563) Overhead Lines Expenses	259,051	120,209
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	138,234,854	136,854,649
97	(566) Miscellaneous Transmission Expenses	3,568,851	4,257,862
98	(567) Rents	2,549,553	1,312,382
99	TOTAL Operation (Enter Total of lines 83 thru 98)	162,697,913	160,047,938
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,060,726	1,334,303
102	(569) Maintenance of Structures	300	395
103	(569.1) Maintenance of Computer Hardware	103,365	36,440
104	(569.2) Maintenance of Computer Software	1,119,442	1,065,683
105	(569.3) Maintenance of Communication Equipment	3,356,135	3,567,267
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,231,343	10,092,385
108	(571) Maintenance of Overhead Lines	22,369,881	19,173,510
109	(572) Maintenance of Underground Lines	169,531	36,881
110	(573) Maintenance of Miscellaneous Transmission Plant	1,607,372	273,467
111	TOTAL Maintenance (Total of lines 101 thru 110)	42,018,095	35,580,331
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	204,716,008	195,628,269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	14,865,204	15,625,451
135	(581) Load Dispatching	13,254,105	13,735,481
136	(582) Station Expenses	4,206,539	3,812,831
137	(583) Overhead Line Expenses	6,624,463	5,762,152
138	(584) Underground Line Expenses	1,186	287
139	(585) Street Lighting and Signal System Expenses	231,056	209,265
140	(586) Meter Expenses	7,978,791	6,564,361
141	(587) Customer Installations Expenses	13,297,857	12,634,849
142	(588) Miscellaneous Expenses	5,452,451	5,887,263
143	(589) Rents	3,011,807	3,253,672
144	TOTAL Operation (Enter Total of lines 134 thru 143)	68,923,459	67,485,612
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	4,424,569	5,493,229
147	(591) Maintenance of Structures	2,476,425	1,828,870
148	(592) Maintenance of Station Equipment	14,330,166	12,622,071
149	(593) Maintenance of Overhead Lines	89,892,555	84,730,396
150	(594) Maintenance of Underground Lines	22,649,570	22,786,414
151	(595) Maintenance of Line Transformers	893,541	883,285
152	(596) Maintenance of Street Lighting and Signal Systems	4,076,102	4,084,559
153	(597) Maintenance of Meters	5,647,204	5,890,644
154	(598) Maintenance of Miscellaneous Distribution Plant	1,787,180	2,745,222
155	TOTAL Maintenance (Total of lines 146 thru 154)	146,177,312	141,064,690
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	215,100,771	208,550,302
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,930,313	2,497,682
160	(902) Meter Reading Expenses	21,907,551	22,553,488
161	(903) Customer Records and Collection Expenses	56,314,393	54,938,892
162	(904) Uncollectible Accounts	14,586,410	12,590,656
163	(905) Miscellaneous Customer Accounts Expenses	205,123	169,927
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	95,943,790	92,750,645

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	302,255	263,903
168	(908) Customer Assistance Expenses	103,945,691	124,155,800
169	(909) Informational and Instructional Expenses	5,081,263	4,435,033
170	(910) Miscellaneous Customer Service and Informational Expenses	183,174	90,169
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	109,512,383	128,944,905
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	68,148,776	66,458,826
182	(921) Office Supplies and Expenses	9,330,613	9,973,883
183	(Less) (922) Administrative Expenses Transferred-Credit	29,007,646	28,375,128
184	(923) Outside Services Employed	10,190,059	9,404,302
185	(924) Property Insurance	24,984,814	23,341,430
186	(925) Injuries and Damages	7,284,849	8,492,514
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	21,857,100	17,926,840
190	(929) (Less) Duplicate Charges-Cr.	6,822,162	6,130,867
191	(930.1) General Advertising Expenses	5,360	20,382
192	(930.2) Miscellaneous General Expenses	15,710,771	16,291,649
193	(931) Rents	6,614,680	6,337,703
194	TOTAL Operation (Enter Total of lines 181 thru 193)	128,297,214	123,741,534
195	Maintenance		
196	(935) Maintenance of General Plant	24,360,143	22,334,950
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	152,657,357	146,076,484
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,737,355,593	2,715,008,321

Schedule Page: 320 Line No.: 5 Column: c

Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 320 Line No.: 49 Column: b

Represents differences between accrued and actual rents.

Schedule Page: 320 Line No.: 187 Column: b

Pensions and benefits expense is associated with labor and generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2011 and 2010, pensions and benefits expense was $156,716,703 and $153,429,891, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Power Purchases					
2	Arizona Public Service Company	LF		NA	NA	NA
3	Arizona Public Service Company	SF		NA	NA	NA
4	Avista Corporation	SF		NA	NA	NA
5	BNP Paribas Energy Trading GP	SF		NA	NA	NA
6	BP Corporation North America, Inc.	SF		NA	NA	NA
7	BP Energy Company	SF		NA	NA	NA
8	Ballard Hog Farms Inc.	LU		0.01	0.01	0.01
9	Barclays Bank PLC	SF		NA	NA	NA
10	Beaver City Corporation	LF		NA	NA	NA
11	Bell Mountain Hydro, LLC	AD		NA	NA	NA
12	Bell Mountain Hydro, LLC	LU		NA	NA	NA
13	Big Top, LLC	AD		NA	NA	NA
14	Big Top, LLC	LU		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
22,900				615,298		615,298	2
94,877				3,506,478	17,567	3,524,045	3
135,310				2,823,766	6,184	2,829,950	4
24,000				424,130		424,130	5
					-22,230,890	-22,230,890	6
535,003				11,435,427		11,435,427	7
53			270	1,872		2,142	8
196,396				5,837,521	-15,928,638	-10,091,117	9
69				5,781		5,781	10
2					2,129	2,129	11
1,057				80,165		80,165	12
-4					-228	-228	13
3,819				240,206		240,206	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Biomass One, L.P.	LU		22.5	20.9	13.7
2	Birch Power Company, Inc.	LU		NA	NA	NA
3	Black Hills Power, Inc.	AD		NA	NA	NA
4	Black Hills Power, Inc.	LU		NA	NA	NA
5	Black Hills Power, Inc.	SF		NA	NA	NA
6	Black Hills Wyoming, Inc.	SF		NA	NA	NA
7	Blanding City Corporation	LF		NA	NA	NA
8	Bonneville Power Administration	LF		575	575	337
9	Bonneville Power Administration	LF		NA	NA	NA
10	Bonneville Power Administration	OS		NA	NA	NA
11	Bonneville Power Administration	SF		NA	NA	NA
12	Box Canyon Limited Partnership	AD		NA	NA	NA
13	Box Canyon Limited Partnership	LU		4.4	4.7	2.7
14	Butter Creek Power, LLC	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)	
111,000			2,133,000	15,646,914	8,326,073	26,105,987	1
13,019				727,137		727,137	2
-158					234,785	234,785	3
187					2,866,004	2,866,004	4
23,841				1,010,786		1,010,786	5
1,264				70,544		70,544	6
420				31,469		31,469	7
			38,410,000			38,410,000	8
					683,756	683,756	9
1,561					54,153	54,153	10
692,986				9,707,365	57,527	9,764,892	11
					1	1	12
25,830			423,218	2,962,228		3,385,446	13
-11					-704	-704	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	Butter Creek Power, LLC	LU		NA	NA	NA
2	CDM Hydroelectric Company	LU		NA	NA	NA
3	CER Generation II, LLC	LU		200	NA	NA
4	California Independent System Operator	AD		NA	NA	NA
5	California Independent System Operator	SF		NA	NA	NA
6	Cameron A. Curtiss	LU		NA	NA	NA
7	Cargill Power Markets, LLC	AD		NA	NA	NA
8	Cargill Power Markets, LLC	SF		NA	NA	NA
9	Cargill, Incorporated	LU		NA	NA	NA
10	Central Oregon Irrigation District	AD		NA	NA	NA
11	Central Oregon Irrigation District	LU		3.5	4.4	3.3
12	Chevron U.S.A. Inc.	LU		NA	NA	NA
13	Citigroup Energy Inc.	AD		NA	NA	NA
14	Citigroup Energy Inc.	SF		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
13,778				862,108		862,108	1
29,782				1,665,175		1,665,175	2
77,732			1,455,484		4,197,475	5,652,959	3
534					27,033	27,033	4
407,897				13,048,834		13,048,834	5
151				7,469		7,469	6
920					289,508	289,508	7
405,361				12,574,345	-621,313	11,953,032	8
3,312				179,536		179,536	9
					-63	-63	10
42,127			400,660	3,670,020		4,070,680	11
48,823				2,724,350		2,724,350	12
258					280	280	13
1,424,459				41,925,415	-17,911,481	24,013,934	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	City of Albany	LU		NA	NA	NA
2	City of Anaheim	SF		NA	NA	NA
3	City of Burbank	SF		NA	NA	NA
4	City of Glendale	SF		NA	NA	NA
5	City of Hurricane	LF		NA	NA	NA
6	City of Preston Idaho	AD		NA	NA	NA
7	City of Preston Idaho	LU		NA	NA	NA
8	City of Redding	SF		NA	NA	NA
9	City of Walla Walla	LU		2.0	1.8	1.5
10	Clatskanie People's Utility District	SF		NA	NA	NA
11	Colorado River Commission of Nevada	SF		NA	NA	NA
12	Commercial Energy Management Inc.	LU		NA	NA	NA
13	Constellation Energy Commodities Group	SF		NA	NA	NA
14	Cottonwood Hydro, 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)	
1,607				102,912		102,912	1
429				10,333		10,333	2
31,208				1,337,466		1,337,466	3
226				7,270		7,270	4
1,885				141,345		141,345	5
					-64	-64	6
1,557				77,724		77,724	7
870				16,760		16,760	8
13,254			139,222	1,866,128		2,005,350	9
2,845				95,510		95,510	10
201				10,476		10,476	11
2,215				117,291		117,291	12
301,265				12,988,360	-60,518	12,927,842	13
3,284				186,378		186,378	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	DB Energy Trading LLC	AD		NA	NA	NA
2	DB Energy Trading LLC	SF		NA	NA	NA
3	Deschutes Valley Water District	LU		5.9	4.3	2.9
4	Deseret Generation & Transmission Coop	LF		100	100	98
5	Deseret Generation & Transmission Coop	OS		NA	NA	NA
6	Deutsche Bank AG	SF		NA	NA	NA
7	Douglas County	LU		0.9	1.2	0.8
8	Douglas County, Inc.	AD		NA	NA	NA
9	Douglas County, Inc.	LU		NA	NA	NA
10	Draper Irrigation Company	IU		NA	NA	NA
11	Dry Creek LLC	LU		NA	NA	NA
12	Duane Wiggins Hydro, Inc.	AD		NA	NA	NA
13	Duane Wiggins Hydro, Inc.	IU		NA	NA	NA
14	EDF Trading North America, LLC	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)	
10					219	219	1
234,338				6,050,630		6,050,630	2
29,734			584,749	3,252,874		3,837,623	3
772,254			14,629,584	14,403,911	3,840,905	32,874,400	4
					1,850	1,850	5
					-3,041,389	-3,041,389	6
7,779			92,668	952,895		1,045,563	7
26					765	765	8
802				17,063		17,063	9
809				31,985		31,985	10
11,797				622,883		622,883	11
7					252	252	12
29				1,432		1,432	13
485,801				17,358,458	-140,569	17,217,889	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Eagle Point Irrigation District	LU		0.7	0.6	0.4
2	El Paso Electric Company	AD		NA	NA	NA
3	El Paso Electric Company	SF		NA	NA	NA
4	Eugene Water & Electric Board	SF		NA	NA	NA
5	Eurus Combine Hills I, LLC	LU		NA	NA	NA
6	Evergreen BioPower, LLC	LU		NA	NA	NA
7	Exelon Power Team	SF		NA	NA	NA
8	ExxonMobil Production Company	LU		NA	NA	NA
9	Falls Creek H.P. Limited Partnership	LU		3.2	3.4	1.8
10	Farmers Irrigation District	AD		NA	NA	NA
11	Farmers Irrigation District	LU		NA	NA	NA
12	Fillmore City Corporation	LF		NA	NA	NA
13	Finley BioEnergy, LLC	LU		NA	NA	NA
14	Flathead Electric Cooperative, Inc.	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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,909			50,185	450,017		500,202	1
-1					-80	-80	2
8,791				258,190		258,190	3
50,405				1,449,625		1,449,625	4
118,643				4,814,534		4,814,534	5
41,696				2,377,780		2,377,780	6
13,400				455,780		455,780	7
620,809				29,219,060		29,219,060	8
16,714			205,013	1,818,462		2,023,475	9
1,293					138,611	138,611	10
25,133				1,504,830		1,504,830	11
182				19,680		19,680	12
27,556				1,760,359		1,760,359	13
494					11,668	11,668	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Four Corners Windfarm, LLC	AD		NA	NA	NA
2	Four Corners Windfarm, LLC	LU		NA	NA	NA
3	Four Mile Canyon Windfarm, LLC	AD		NA	NA	NA
4	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
5	George DeRuyter & Sons Dairy	LU		0.7	1.0	0.6
6	Georgetown Irrigation Company	LU		NA	NA	NA
7	Gila River Power LLC	SF		NA	NA	NA
8	Grand Valley Power	LF		NA	NA	NA
9	GrowPro, Inc.	IU		NA	NA	NA
10	Harold Foster & Robert Walker	LU		NA	NA	NA
11	Heber Light & Power Company	LF		NA	NA	NA
12	Hermiston Generating Company, L.P.	AD		NA	NA	NA
13	Hermiston Generating Company, L.P.	LU		240	227	156
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)	
21					1,355	1,355	1
30,309				1,898,820		1,898,820	2
-25					-1,489	-1,489	3
27,146				1,706,620		1,706,620	4
6,267			12,848	384,431		397,279	5
2,414				132,485		132,485	6
129,598				4,819,284		4,819,284	7
101				18,632		18,632	8
				13		13	9
753				27,179		27,179	10
3,427				283,970		283,970	11
1					-234,592	-234,592	12
1,157,119			35,700,425	60,085,319	431,730	96,217,474	13
1,152,472				28,802,826	-4,291,267	24,511,559	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Idaho Falls, City of	AD		NA	NA	NA
2	Idaho Falls, City of	LU		NA	NA	NA
3	Idaho Falls, City of	SF		NA	NA	NA
4	Idaho Power Company	SF		NA	NA	NA
5	Ingram Warm Springs Ranch Partnership	LU		NA	NA	NA
6	Intermountain Power Agency	LU		NA	NA	NA
7	J. Aron & Company	SF		NA	NA	NA
8	JP Morgan Ventures Energy Corporation	SF		NA	NA	NA
9	Jake Amy	LU		NA	NA	NA
10	Kennecott Utah Copper LLC	LU		NA	NA	NA
11	Lacomb Irrigation District	LU		NA	NA	NA
12	Lehman Brothers Commodity Services	SF		NA	NA	NA
13	Logan City	OS		NA	NA	NA
14	Los Angeles Dept. of Water & Power	OS		NA	NA	NA
	Total					

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-295,099	-295,099	1
48,564					2,725,881	2,725,881	2
4,010				140,070		140,070	3
131,265				2,082,007	4,970	2,086,977	4
1,200				66,783		66,783	5
571,555				27,759,598		27,759,598	6
42,400				1,585,196	-18,224,034	-16,638,838	7
285,912				8,122,777	-15,045,428	-6,922,651	8
1,943				103,648		103,648	9
33,367				1,375,479	3,259,698	4,635,177	10
4,639				114,998	34,803	149,801	11
					131,592	131,592	12
12				698		698	13
1,700				42,500		42,500	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Los Angeles Dept. of Water & Power	SF		NA	NA	NA
2	Lower Valley Energy, Inc.	IU		NA	NA	NA
3	Loyd Fery	LU		NA	NA	NA
4	Macquarie Energy LLC	SF		NA	NA	NA
5	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
6	Middle Fork Irrigation District	LU		NA	NA	NA
7	Mink Creek Hydro LLC	LU		NA	NA	NA
8	Monsanto Company	IU		NA	NA	NA
9	Morgan City Corporation	LF		NA	NA	NA
10	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
11	Morgan Stanley Capital Group, Inc.	IF		100	0	0
12	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
13	Mountain Wind Power II, LLC	LU		NA	NA	NA
14	Mountain Wind Power, 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)	
80,424				4,050,357		4,050,357	1
7,325				492,369		492,369	2
338				21,863		21,863	3
322,624				6,876,419	-235,068	6,641,351	4
5,925				329,493		329,493	5
24,230				1,374,459		1,374,459	6
11,168				608,550		608,550	7
					17,109,978	17,109,978	8
21				2,226		2,226	9
1,191					44,445	44,445	10
			3,150,000			3,150,000	11
1,654,328				51,266,046	-14,838,752	36,427,294	12
240,845				15,439,121		15,439,121	13
186,503				10,367,567		10,367,567	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Nephi City Corporation	LF		NA	NA	NA
2	Nevada Power Company	OS		NA	NA	NA
3	Nevada Power Company	SF		NA	NA	NA
4	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
5	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
6	Noble Americas Gas & Power Corp.	SF		NA	NA	NA
7	NorthWestern Corporation	SF		NA	NA	NA
8	Nucor Corporation	IF		NA	NA	NA
9	O.J. Power Company	AD		NA	NA	NA
10	O.J. Power Company	LU		NA	NA	NA
11	Oregon Environmental Industries, LLC	LU		NA	NA	NA
12	Oregon Institute of Technology	AD		NA	NA	NA
13	Oregon Institute of Technology	LU		NA	NA	NA
14	Oregon State University	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)	
17				1,828		1,828	1
100				3,200		3,200	2
60,022				2,213,505	54,861	2,268,366	3
4,450				107,170		107,170	4
1,990				110,156		110,156	5
1,590				49,305		49,305	6
299				1,250	7,120	8,370	7
					4,998,000	4,998,000	8
-16					-929	-929	9
847				43,809		43,809	10
23,657				1,339,099		1,339,099	11
-15					-525	-525	12
				1		1	13
87				1,498		1,498	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Oregon Trail Windfarm, LLC	AD		NA	NA	NA
2	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
3	PPL EnergyPlus, LLC	SF		NA	NA	NA
4	Pacific Canyon Windfarm, LLC	AD		NA	NA	NA
5	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
6	Pacific Gas & Electric Company	SF		NA	NA	NA
7	Pacific Northwest Generating Coop.	SF		NA	NA	NA
8	Paul Luckey	LU		NA	NA	NA
9	Payson City Corporation	LF		NA	NA	NA
10	Platte River Power Authority	SF		NA	NA	NA
11	Portland General Electric Company	AD		NA	NA	NA
12	Portland General Electric Company	LF		NA	NA	NA
13	Portland General Electric Company	OS		NA	NA	NA
14	Portland General Electric 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)	
-20					-1,317	-1,317	1
27,236				1,717,749		1,717,749	2
118,749				3,313,878		3,313,878	3
-19					-1,241	-1,241	4
20,114				1,266,425		1,266,425	5
10,800				209,500		209,500	6
1,600				50,300		50,300	7
278				36,807		36,807	8
15				1,709		1,709	9
3,410					99,438	99,438	10
					2,748	2,748	11
12,001					345,000	345,000	12
					2,400	2,400	13
52,783				1,419,598	8,087	1,427,685	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Power County Wind Park North, LLC	LU		NA	NA	NA
2	Power County Wind Park South, LLC	LU		NA	NA	NA
3	Powerex Corporation	SF		NA	NA	NA
4	Provo City Corporation	LF		NA	NA	NA
5	Public Service Company of Colorado	SF		NA	NA	NA
6	Public Service Company of New Mexico	SF		NA	NA	NA
7	PUD #1 of Chelan County	LU		NA	NA	NA
8	PUD #1 of Chelan County	OS		NA	NA	NA
9	PUD #1 of Chelan County	SF		NA	NA	NA
10	PUD #1 of Cowlitz County	AD		NA	NA	NA
11	PUD #1 of Cowlitz County	OS		NA	NA	NA
12	PUD #1 of Douglas County	AD		NA	NA	NA
13	PUD #1 of Douglas County	AD		NA	NA	NA
14	PUD #1 of Douglas County	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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,941				147,460		147,460	1
2,910				156,693		156,693	2
247,796				8,598,650	30,412	8,629,062	3
101				9,647		9,647	4
26,774				550,218		550,218	5
164,296				5,305,545	141,817	5,447,362	6
358,993					3,495,315	3,495,315	7
					1,200	1,200	8
43,081				1,050,810	2,132	1,052,942	9
					-38,499	-38,499	10
					-509	-509	11
					-104,836	-104,836	12
					-118,185	-118,185	13
69,941				1,803,976		1,803,976	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	PUD #1 of Douglas County	LU		NA	NA	NA
2	PUD #1 of Douglas County	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	PUD #1 of Snohomish County	SF		NA	NA	NA
6	PUD #2 of Grant County	AD		NA	NA	NA
7	PUD #2 of Grant County	LF		14	NA	NA
8	PUD #2 of Grant County	LU		NA	NA	NA
9	PUD #2 of Grant County	SF		NA	NA	NA
10	Puget Sound Energy, Inc.	SF		NA	NA	NA
11	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
12	Ralphs Ranch, Inc.	AD		NA	NA	NA
13	Ralphs Ranch, Inc.	LU		NA	NA	NA
14	Rock River 1, 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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
254,785					3,266,126	3,266,126	1
32,296				921,750	445	922,195	2
					8,502	8,502	3
915				27,915		27,915	4
44,160				781,720		781,720	5
					-16,915	-16,915	6
87,600			185,558	5,860,350	321,627	6,367,535	7
427,303				9,504,829	-6,393,833	3,110,996	8
45,292				1,054,368	3,201	1,057,569	9
246,935				6,776,147	9,629	6,785,776	10
43,124				1,501,853		1,501,853	11
-10					-713	-713	12
212				28,046		28,046	13
136,079				4,828,079		4,828,079	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Rocky Mountain Generation Coop.	SF		NA	NA	NA
2	Roseburg Forest Products Company	LU		NA	NA	NA
3	Roseburg Forest Products Company	OS		NA	NA	NA
4	Rough & Ready Lumber Company	LU		NA	NA	NA
5	Roush Hydro Inc.	LU		NA	NA	NA
6	Sacramento Municipal Utility District	AD		NA	NA	NA
7	Sacramento Municipal Utility District	LF		NA	NA	NA
8	Sacramento Municipal Utility District	SF		NA	NA	NA
9	Salt River Project	SF		NA	NA	NA
10	San Diego Gas & Electric Company	AD		NA	NA	NA
11	San Diego Gas & Electric Company	SF		NA	NA	NA
12	Sand Ranch Windfarm, LLC	AD		NA	NA	NA
13	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
14	Santiam Water Control District	LU		0.2	0.2	0.2
	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)	
5,336				124,292		124,292	1
96,781				5,491,820		5,491,820	2
39,618				2,112,297		2,112,297	3
8,811				563,395		563,395	4
329				21,306		21,306	5
					-21,371	-21,371	6
200,731				3,629,216		3,629,216	7
3,565				83,951		83,951	8
121,348				4,788,150	1,193	4,789,343	9
250							10
800				26,000		26,000	11
-22					-1,459	-1,459	12
24,152				1,518,431		1,518,431	13
1,603			13,632	147,536		161,168	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Seattle City Light	SF		NA	NA	NA
2	Sempra Energy Trading LLC	SF		NA	NA	NA
3	Sempra Generation	SF		NA	NA	NA
4	Shell Energy North America (US), L.P.	OS		NA	NA	NA
5	Shell Energy North America (US), L.P.	SF		NA	NA	NA
6	Shoshone Irrigation District	LU		2.5	1.4	1.1
7	Sierra Pacific Power Company	SF		NA	NA	NA
8	Sierra Pacific Power Company	SF		NA	NA	NA
9	Simplot Phosphates LLC	LU		10	12	9
10	Slate Creek Hydro Company, Inc.	AD		NA	NA	NA
11	Slate Creek Hydro Company, Inc.	LU		3.7	2.3	1.6
12	Southern California Edison Company	SF		NA	NA	NA
13	Southwestern Public Service Company	SF		NA	NA	NA
14	Spanish Fork City Corporation	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)	
187,077				4,175,988	3,859	4,179,847	1
					-14,833,291	-14,833,291	2
500				15,844		15,844	3
					500	500	4
383,322				9,774,871	-36,619,253	-26,844,382	5
9,573			170,763	397,103		567,866	6
20,940				899,458	2,371	901,829	7
2,787					172,206	172,206	8
73,365			296,400	3,325,035		3,621,435	9
					66,812	66,812	10
14,810			202,903	1,517,786		1,720,689	11
65,801				2,086,341		2,086,341	12
4,008				124,797		124,797	13
					-325	-325	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
2	Sprague Hydro, LLC	LU		0.4	0.7	0.4
3	Springville City Corporation	LF		NA	NA	NA
4	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
5	Strawberry Electric Service District	LF		NA	NA	NA
6	Sunnyside Cogeneration Associates	LU		52	53	52
7	Swalley Irrigation District	LU		NA	NA	NA
8	Tacoma Power	SF		NA	NA	NA
9	Tata Chemicals (Soda Ash) Partners	OS		NA	NA	NA
10	Tesoro Refining and Marketing Company	LU		NA	NA	NA
11	Thayn Hydro LLC	LU		0.2	0.4	0.2
12	The Energy Authority, Inc.	SF		NA	NA	NA
13	The Town of the City of Buffalo	AD		NA	NA	NA
14	The Town of the City of Buffalo	LU		0.2	0.2	0.2
	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)	
47,380				2,424,027		2,424,027	1
3,127			46,919	359,249		406,168	2
49				6,137		6,137	3
7,839				429,137		429,137	4
57				4,985		4,985	5
419,308			10,576,481	15,591,998		26,168,479	6
2,362				151,069		151,069	7
24,312				545,465	1,413	546,878	8
2,544				37,903		37,903	9
32,430				1,259,118		1,259,118	10
2,049			58,498	162,046		220,544	11
29,593				707,676		707,676	12
							13
1,849			31,896	172,176		204,072	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Three Buttes Windpower, LLC	LU		NA	NA	NA
2	Threemile Canyon Wind I, LLC	AD		NA	NA	NA
3	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
4	Top of The World Wind Energy LLC	LU		NA	NA	NA
5	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
6	TransCanada Energy Sales Ltd.	SF		NA	NA	NA
7	Tri-State Gen. & Trans.	LF		25	25	20
8	Tri-State Gen. & Trans.	SF		NA	NA	NA
9	Tucson Electric Power Company	SF		NA	NA	NA
10	UNS Electric, Inc.	SF		NA	NA	NA
11	US Magnesium LLC	LF		NA	NA	NA
12	US Magnesium LLC	LU		NA	NA	NA
13	United States Air Force at Hill Base	LU		NA	NA	NA
14	Utah Associated Municipal Power	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)	
359,800				22,902,276		22,902,276	1
					24	24	2
25,147				1,604,816		1,604,816	3
685,448				45,239,588		45,239,588	4
112,313				3,342,811		3,342,811	5
200				11,000		11,000	6
131,446			6,051,000	3,199,396		9,250,396	7
33,966				743,835	310,140	1,053,975	8
51,036				1,621,015	942	1,621,957	9
180,540				5,344,287		5,344,287	10
					5,262,758	5,262,758	11
155,597				6,233,791		6,233,791	12
14,381				709,264		709,264	13
4,444				153,090		153,090	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Utah Associated Municipal Power	SF		NA	NA	NA
2	Utah Municipal Power Agency	SF		NA	NA	NA
3	Wagon Trail, LLC	AD		NA	NA	NA
4	Wagon Trail, LLC	LU		NA	NA	NA
5	Ward Butte Windfarm, LLC	AD		NA	NA	NA
6	Ward Butte Windfarm, LLC	LU		NA	NA	NA
7	Warm Springs Forest Products	LU		NA	NA	NA
8	Wasatch Integrated Waste Management	LU		NA	NA	NA
9	Weber County	LU		NA	NA	NA
10	Western Area Power Administration	AD		NA	NA	NA
11	Western Area Power Administration	SF		NA	NA	NA
12	Western Area Power Administration	SF		NA	NA	NA
13	Wolverine Creek Energy, LLC	AD		NA	NA	NA
14	Wolverine Creek Energy, LLC	LU		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
14,615				454,461		454,461	1
100				4,000		4,000	2
93					6,344	6,344	3
7,644				480,567		480,567	4
-14					-893	-893	5
18,864				1,181,376		1,181,376	6
				10		10	7
447				22,273		22,273	8
4,846				224,046		224,046	9
-848					-21,562	-21,562	10
27,126					764,490	764,490	11
4,708				90,938	27	90,965	12
-164					-9,063	-9,063	13
198,629				11,052,658		11,052,658	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

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	Yakima-Tieton Irrigation District	LU		NA	NA	NA
2	Settlement/Reserves	AD		NA	NA	NA
3	Netting - Trading	AD		NA	NA	NA
4	Netting - Bookouts	AD		NA	NA	NA
5	Net Power Cost/REC Deferrals	AD		NA	NA	NA
6	Accrual	NA				
7						
8	Power Exchanges					
9	Arizona Public Service Company	EX	306	NA	NA	NA
10	Avista Corporation	EX	554	NA	NA	NA
11	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
12	Black Hills Power, Inc.	EX	246	NA	NA	NA
13	Bonneville Power Administration	AD	237	NA	NA	NA
14	Bonneville Power Administration	EX	237	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,876				355,706		355,706	1
					-2,675,134	-2,675,134	2
					-11,500,014	-11,500,014	3
-5,705,305					-167,137,515	-167,137,515	4
					-94,016,281	-94,016,281	5
					-534,465	-534,465	6
							7
							8
	565,323	571,256			906,764	906,764	9
	1,789						10
	9,697	206			251,795	251,795	11
	92						12
		4,466			-11,164	-11,164	13
		32,799			-79,890	-79,890	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	EX	256	NA	NA	NA
2	Bonneville Power Administration	EX	368	NA	NA	NA
3	Bonneville Power Administration	EX	411	NA	NA	NA
4	Bonneville Power Administration	EX	554	NA	NA	NA
5	Bonneville Power Administration	EX		NA	NA	NA
6	Bonneville Power Administration	EX	T-11	NA	NA	NA
7	Bonneville Power Administration	EX	T-12	NA	NA	NA
8	City of Redding	EX	364	NA	NA	NA
9	Colockum Transmission Company	EX	T-12	NA	NA	NA
10	Constellation Energy Commodities Group	EX	T-11	NA	NA	NA
11	Deseret Generation & Transmission Coop	AD	280	NA	NA	NA
12	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
13	Deseret Generation & Transmission Coop	EX	21	NA	NA	NA
14	Emerald People's Utility District	AD	351	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.
	259				5,698	5,698	1
	249,993	249,992			1,500,000	1,500,000	2
	941,450	963,256			-660,000	-660,000	3
	207,703	17,056					4
	9,447,547	9,447,547			-36,755,000	-36,755,000	5
	11,606	9,465			40,948	40,948	6
	156,020	111,559			1,421,058	1,421,058	7
	115,883	117,207			-104,223	-104,223	8
		102,511					9
	806	53			11,656	11,656	10
	460	-2,301			100,992	100,992	11
	30,459	66,687			-1,364,551	-1,364,551	12
		1,690					13
					-6	-6	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Emerald People's Utility District	EX	351	NA	NA	NA
2	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
3	Iberdrola Renewables, Inc.	EX	T-11	NA	NA	NA
4	Idaho Power Company	EX	380	NA	NA	NA
5	Intermountain Renewable Power, LLC	EX	T-11	NA	NA	NA
6	JP Morgan Ventures Energy Corporation	EX	T-11	NA	NA	NA
7	Los Angeles Dept. of Water & Power	EX	OV-1	NA	NA	NA
8	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
9	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
10	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
11	Noble Americas Energy Solutions LLC	EX	T-11	NA	NA	NA
12	Portland General Electric Company	EX	554	NA	NA	NA
13	Powerex Corporation	EX	T-11	NA	NA	NA
14	Public Service Company of Colorado	EX	319	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)	
		571			-14,270	-14,270	1
	20,002	19,933			4,148	4,148	2
	5,097	558			116,340	116,340	3
	416,278	299,783					4
	2,502	1,845			16,774	16,774	5
	2,170	1,604			14,199	14,199	6
	2,275				164,407	164,407	7
		1,592			-134,454	-134,454	8
		683			-57,633	-57,633	9
	130,212	87,913			512,208	512,208	10
	3,239	5,450			-99,324	-99,324	11
	132,557	131,551					12
	656	3,270			-61,606	-61,606	13
	5,460						14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Public Service Company of Colorado	EX	320	NA	NA	NA
2	Public Service Company of Colorado	EX	T-12	NA	NA	NA
3	PUD #1 of Chelan County	EX	554	NA	NA	NA
4	PUD #1 of Cowlitz County	EX	554	NA	NA	NA
5	Seattle City Light	AD	T-11	NA	NA	NA
6	Seattle City Light	EX	554	NA	NA	NA
7	Seattle City Light	EX	T-11	NA	NA	NA
8	Southern California Edison Company	EX	T-11	NA	NA	NA
9	Tri-State Gen. & Trans.	AD	319	NA	NA	NA
10	Tri-State Gen. & Trans.	AD	T-11	NA	NA	NA
11	Tri-State Gen. & Trans.	EX	319	NA	NA	NA
12	Tri-State Gen. & Trans.	EX	T-11	NA	NA	NA
13	Utah Associated Municipal Power	AD	T-11	NA	NA	NA
14	Utah Associated Municipal Power	EX	T-11	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	1,095,097	1,090,347			4,500,000	4,500,000	1
	78,842	79,999			-203,681	-203,681	2
	94,164	103,920			-92,421	-92,421	3
	228,957	264,313					4
					-5,031	-5,031	5
	356,254	352,058			-223,712	-223,712	6
	10,120	8,661			34,148	34,148	7
	66,972	60,015			121,641	121,641	8
					7,358	7,358	9
	-1	37			-1,019	-1,019	10
	5,465				10,456	10,456	11
	15,493	1,834			390,906	390,906	12
	4,664	-7,001			379,950	379,950	13
	119,482	52,183			1,784,393	1,784,393	14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
2	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
3	Western Area Power Administration	AD	LAS-4	NA	NA	NA
4	Western Area Power Administration	EX	LAS-4	NA	NA	NA
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		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)	
	38,727	7,508			964,955	964,955	1
	2,174	10,673			-240,238	-240,238	2
	-15,466	12,058			-336,370	-336,370	3
	1,292	57,648			-704,044	-704,044	4
6,730							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
14,094,451	14,561,771	14,342,455	115,021,376	694,385,193	-411,145,301	398,261,268	

Schedule Page: 326 Line No.: 2 Column: b
Arizona Public Service Company - Contract Termination Date: October 31, 2020.

Schedule Page: 326 Line No.: 3 Column: l
Line loss.

Schedule Page: 326 Line No.: 4 Column: l
Reserve Share.

Schedule Page: 326 Line No.: 6 Column: l
Financial Swap.

Schedule Page: 326 Line No.: 9 Column: l
Financial Swap.

Schedule Page: 326 Line No.: 10 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 11 Column: l
Settlement adjustment.

Schedule Page: 326 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 1 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 3 Column: l
Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 4 Column: l
Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 7 Column: b
Blanding City Corporation - Contract Termination Date: March 31, 2012.

Schedule Page: 326.1 Line No.: 8 Column: b
Bonneville Power Administration - Contract Termination Date: August 31, 2011.

Schedule Page: 326.1 Line No.: 9 Column: b
Bonneville Power Administration - Contract Termination Date: 30 days written notice.

Schedule Page: 326.1 Line No.: 9 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 10 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 10 Column: l
Ancillary services.

Schedule Page: 326.1 Line No.: 11 Column: l
Reserve Share.

Schedule Page: 326.1 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.1 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 14 Column: l
Settlement adjustment.

Schedule Page: 326.2 Line No.: 3 Column: l

Variable operating, maintenance and fuel expense associated with gas facility located in West Valley, Utah.

Schedule Page: 326.2 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “CALIFORNIA INDEPENDENT SYSTEM OPERATOR” ON PAGES 326–327: Complete name is California Independent System Operator Corporation.

Schedule Page: 326.2 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 4 Column: l

Settlement adjustment.

Schedule Page: 326.2 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 7 Column: l

Settlement adjustment.

Schedule Page: 326.2 Line No.: 8 Column: l

Financial Swap.

Schedule Page: 326.2 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.2 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.2 Line No.: 14 Column: l

Financial Swap.

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

City of Hurricane - Contract Termination Date: August 31, 2012.

Schedule Page: 326.3 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 6 Column: l

Settlement adjustment.

Schedule Page: 326.3 Line No.: 13 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “CONSTELLATION ENERGY COMMODITIES GROUP” ON PAGES 326–327: Complete name is Constellation Energy Commodities Group, Inc.

Schedule Page: 326.3 Line No.: 13 Column: l

Financial Swap.

Schedule Page: 326.4 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.4 Line No.: 1 Column: l

Settlement adjustment.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “DESERET GENERATION & TRANSMISSION COOP” ON PAGES 326–327: Complete name is Deseret Generation and Transmission Cooperative.

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

Deseret Generation and Transmission Cooperative - Contract Termination Date: September 30, 2024.

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

Purchased power charges reimbursing counterparty for coal fired generation unit operation and maintenance costs.

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

Secondary, economy and/or non-firm.

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

Liquidated damages.

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

Financial Swap.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.4 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 326.4 Line No.: 12 Column: l

Settlement adjustment.

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

Financial Swap.

Schedule Page: 326.5 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.5 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.5 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.5 Line No.: 12 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 14 Column: b

Flathead Electric Cooperative, Inc. - Contract Termination Date: September 30, 2016.

Schedule Page: 326.5 Line No.: 14 Column: l

Line loss.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 11 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

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

Settlement adjustment.

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

Settlement adjustment.

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

On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.6 Line No.: 14 Column: l

Financial Swap.

Schedule Page: 326.7 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.7 Line No.: 1 Column: l

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.7 Line No.: 2 Column: l

Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

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

Reserve Share.

Schedule Page: 326.7 Line No.: 7 Column: l

Financial Swap.

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

Financial Swap.

Schedule Page: 326.7 Line No.: 10 Column: l

Compensation for self-generation.

Schedule Page: 326.7 Line No.: 11 Column: l

Fixed annual payment.

Schedule Page: 326.7 Line No.: 12 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “LEHMAN BROTHERS COMMODITY SERVICES” ON PAGES 326–327: Complete name is Lehman Brothers Commodity Services, Inc.

Schedule Page: 326.7 Line No.: 12 Column: l

Termination settlement.

Schedule Page: 326.7 Line No.: 13 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.7 Line No.: 14 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “LOS ANGELES DEPT. OF WATER & POWER" ON PAGES 326–327: Complete name is Los Angeles Department of Water and Power.

Schedule Page: 326.7 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.8 Line No.: 4 Column: l

Financial Swap.

Schedule Page: 326.8 Line No.: 8 Column: l

Compensation for interruptible service and operating reserves.

Schedule Page: 326.8 Line No.: 9 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.8 Line No.: 12 Column: l

Financial Swap.

Schedule Page: 326.9 Line No.: 1 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.9 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.9 Line No.: 3 Column: l

Line loss.

Schedule Page: 326.9 Line No.: 7 Column: l

Reserve Share.

Schedule Page: 326.9 Line No.: 8 Column: l

Ancillary services.

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.: 12 Column: b

Settlement adjustment.

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) __ An Original (2) X A Resubmission	06/28/2012	2011/Q4

FOOTNOTE DATA

Schedule Page: 326.9 Line No.: 12 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 1 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 1 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 4 Column: l
Settlement adjustment.

Schedule Page: 326.10 Line No.: 7 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PACIFIC NORTHWEST GENERATING COOP." ON PAGES 326–327: Complete name is Pacific Northwest Generating Cooperative, Inc.

Schedule Page: 326.10 Line No.: 9 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 10 Column: l
Line loss.

Schedule Page: 326.10 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 11 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.10 Line No.: 12 Column: b
Portland General Electric Company - Contract Termination Date: Round Butte project no longer operating for power production purposes.

Schedule Page: 326.10 Line No.: 12 Column: l
Operation expense plus amortization of unrecovered costs of Cove Project.

Schedule Page: 326.10 Line No.: 13 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.10 Line No.: 13 Column: l
Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.10 Line No.: 14 Column: l
Reserve Share.

Schedule Page: 326.11 Line No.: 3 Column: l
Financial Swap.

Schedule Page: 326.11 Line No.: 4 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.11 Line No.: 6 Column: l
Line loss.

Schedule Page: 326.11 Line No.: 7 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF CHELAN COUNTY" ON PAGES 326–327: Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 326.11 Line No.: 7 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 8 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 8 Column: l
Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.11 Line No.: 9 Column: l
Reserve Share.

Schedule Page: 326.11 Line No.: 10 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF COWLITZ COUNTY” ON PAGES 326–327: Complete name is Public Utility District No. 1 of Cowlitz County.

Schedule Page: 326.11 Line No.: 10 Column: b
Settlement adjustment.
Schedule Page: 326.11 Line No.: 10 Column: l
Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.
Schedule Page: 326.11 Line No.: 11 Column: b
Secondary, economy and/or non-firm.
Schedule Page: 326.11 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: 326.11 Line No.: 12 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF DOUGLAS COUNTY" ON PAGES 326–327: Complete name is Public Utility District No. 1 of Douglas County.
Schedule Page: 326.11 Line No.: 12 Column: b
Settlement adjustment.
Schedule Page: 326.11 Line No.: 12 Column: l
Settlement adjustment.
Schedule Page: 326.11 Line No.: 13 Column: b
Settlement adjustment.
Schedule Page: 326.11 Line No.: 13 Column: l
Operating expense, bond interest, amortization and taxes.
Schedule Page: 326.11 Line No.: 14 Column: b
Public Utility District No. 1 of Douglas County - Contract Termination Date: August 31, 2018.
Schedule Page: 326.12 Line No.: 1 Column: l
Operating expense, bond interest, amortization and taxes.
Schedule Page: 326.12 Line No.: 2 Column: l
Reserve Share.
Schedule Page: 326.12 Line No.: 3 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF LEWIS COUNTY" ON PAGES 326–327: Complete name is Public Utility District No. 1 of Lewis County.
Schedule Page: 326.12 Line No.: 3 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 3 Column: l
Settlement adjustment.
Schedule Page: 326.12 Line No.: 4 Column: b
Public Utility District No. 1 of Lewis County - Contract Termination Date: 60 days written notice.
Schedule Page: 326.12 Line No.: 5 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #1 OF SNOHOMISH COUNTY" ON PAGES 326–327: Complete name is Public Utility District No. 1 of Snohomish County.
Schedule Page: 326.12 Line No.: 6 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUD #2 OF GRANT COUNTY" ON PAGES 326–327: Complete name is Public Utility District No. 2 of Grant County.
Schedule Page: 326.12 Line No.: 6 Column: b
Settlement adjustment.
Schedule Page: 326.12 Line No.: 6 Column: l
Settlement adjustment.
Schedule Page: 326.12 Line No.: 7 Column: b
Public Utility District No. 2 of Grant County - Contract Termination Date: August 15, 2012.
Schedule Page: 326.12 Line No.: 7 Column: l
Ancillary services.
Schedule Page: 326.12 Line No.: 8 Column: l

Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.12 Line No.: 9 Column: l

Reserve Share.

Schedule Page: 326.12 Line No.: 10 Column: l

Reserve Share.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.13 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “ROCKY MOUNTAIN GENERATION COOP." ON PAGES 326–327: Complete name is Rocky Mountain Generation Cooperative, Inc.

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

Secondary, economy and/or non-firm.

Schedule Page: 326.13 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 6 Column: l

Settlement adjustment.

Schedule Page: 326.13 Line No.: 7 Column: b

Sacramento Municipal Utility District - Contract Termination Date: December 31, 2014.

Schedule Page: 326.13 Line No.: 9 Column: l

Line loss.

Schedule Page: 326.13 Line No.: 10 Column: b

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.13 Line No.: 12 Column: l

Settlement adjustment.

Schedule Page: 326.14 Line No.: 1 Column: l

Reserve Share.

Schedule Page: 326.14 Line No.: 2 Column: l

Financial Swap.

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

Secondary, economy and/or non-firm.

Schedule Page: 326.14 Line No.: 4 Column: l

Liability associated with paper pond at hydro facility located on the Lewis River in the state of Washington.

Schedule Page: 326.14 Line No.: 5 Column: l

Financial Swap.

Schedule Page: 326.14 Line No.: 7 Column: l

Reserve Share.

Schedule Page: 326.14 Line No.: 8 Column: l

Line loss.

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

Settlement adjustment.

Schedule Page: 326.14 Line No.: 10 Column: l

Settlement adjustment.

Schedule Page: 326.14 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.14 Line No.: 14 Column: l

Settlement adjustment.

Schedule Page: 326.15 Line No.: 3 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.15 Line No.: 5 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.15 Line No.: 8 Column: l

Reserve Share.

Schedule Page: 326.15 Line No.: 9 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 2 Column: l

Settlement adjustment.

Schedule Page: 326.16 Line No.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “TRI-STATE GEN. & TRANS." ON PAGES 326–327: Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 326.16 Line No.: 7 Column: b

Tri-State Generation and Transmission Association, Inc. - Contract Termination Date: December 31, 2020.

Schedule Page: 326.16 Line No.: 8 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 9 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 11 Column: b

US Magnesium LLC - Contract Termination Date: December 31, 2014.

Schedule Page: 326.16 Line No.: 11 Column: l

Ancillary services.

Schedule Page: 326.16 Line No.: 13 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “UNITED STATES AIR FORCE AT HILL BASE" ON PAGES 326–327: Complete name is United States Air Force at Hill Air Force Base.

Schedule Page: 326.16 Line No.: 14 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “UTAH ASSOCIATED MUNICIPAL POWER" ON PAGES 326–327: Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 326.16 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.17 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.17 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 5 Column: l

Settlement adjustment.

Schedule Page: 326.17 Line No.: 8 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “WASATCH INTEGRATED WASTE MANAGEMENT" ON PAGES 326 – 327: Complete name is Wasatch Integrated Waste Management District.

Schedule Page: 326.17 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 10 Column: l

Line loss.

Schedule Page: 326.17 Line No.: 11 Column: l

Line loss.

Schedule Page: 326.17 Line No.: 12 Column: l

Reserve Share.

Schedule Page: 326.17 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.17 Line No.: 13 Column: l
Settlement adjustment.

Schedule Page: 326.18 Line No.: 2 Column: l
Release of reserve for potential liabilities associated with curtailment on receipt of energy and settlement for unmetered megawatt hours.

Schedule Page: 326.18 Line No.: 3 Column: l
Reflects transactions that did not physically settle.

Schedule Page: 326.18 Line No.: 4 Column: l
Reflects transactions that did not physically settle.

Schedule Page: 326.18 Line No.: 5 Column: l
Regulatory net power cost and renewable energy credit deferrals.

Schedule Page: 326.18 Line No.: 6 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.

Schedule Page: 326.18 Line No.: 9 Column: l
Exchange energy expense.

Schedule Page: 326.18 Line No.: 11 Column: l
Imbalance energy.

Schedule Page: 326.18 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 326.18 Line No.: 13 Column: l
Storage and exchange charges.

Schedule Page: 326.18 Line No.: 14 Column: l
Storage and exchange charges.

Schedule Page: 326.19 Line No.: 1 Column: l
Exchange energy expense. Storage and exchange charges.

Schedule Page: 326.19 Line No.: 2 Column: l
Settlement for historical billing dispute.

Schedule Page: 326.19 Line No.: 3 Column: l
Exchange energy expense.

Schedule Page: 326.19 Line No.: 5 Column: c
Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.19 Line No.: 5 Column: h
These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.19 Line No.: 5 Column: i
These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.19 Line No.: 5 Column: l
Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.19 Line No.: 6 Column: l
Imbalance energy.

Schedule Page: 326.19 Line No.: 7 Column: l
Exchange energy expense. Imbalance energy.

Schedule Page: 326.19 Line No.: 8 Column: l
Imbalance energy.

Schedule Page: 326.19 Line No.: 10 Column: l
Imbalance energy.

Schedule Page: 326.19 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 326.19 Line No.: 11 Column: l
Imbalance energy.

Schedule Page: 326.19 Line No.: 12 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 14 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 14 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 1 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 2 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 5 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 6 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 7 Column: l

Station service for third party wind project.

Schedule Page: 326.20 Line No.: 8 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.20 Line No.: 9 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.20 Line No.: 10 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 11 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 1 Column: l

Storage and exchange charges.

Schedule Page: 326.21 Line No.: 2 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 3 Column: l

Storage and exchange charges.

Schedule Page: 326.21 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 5 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 6 Column: l

Exchange energy expense.

Schedule Page: 326.21 Line No.: 7 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 8 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 10 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 11 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 12 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.

Schedule Page: 326.22 Line No.: 1 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 2 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.22 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.22 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.22 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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Arizona Public Service Company	Arizona Public Service Company		OS
2	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	SFP
5	Basin Electric Power Cooperative	Western Area Power Administration		NF
6	Black Hills/Colorado Electric Utility Company			NF
7	Black Hills/Colorado Electric Utility Company			SFP
8	Black Hills Corporation		Montana-Dakota Utilities	FNO
9	Black Hills Corporation		Montana-Dakota Utilities	AD
10	Black Hills Corporation			NF
11	Black Hills Corporation			AD
12	Black Hills Corporation			SFP
13	Black Hills Corporation			AD
14	Black Hills Corporation		Black Hills, Inc.	LFP
15	Black Hills Corporation		Black Hills, Inc.	AD
16	Bonneville Power Administration			OS
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	Bonneville Power Administration	LFP
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
21	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	FNO
22	Bonneville Power Administration	Bonneville Power Administration	Umpqua Indian Utility Cooperative	AD
23	Bonneville Power Administration	Bonneville Power Administration	Benton REA	FNO
24	Bonneville Power Administration	Bonneville Power Administration	Benton REA	AD
25	Bonneville Power Administration	Bonneville Power Administration	Umatilla Elec & Columbia	FNO
26	Bonneville Power Administration	Bonneville Power Administration	Umatilla Elec & Columbia	AD
27	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	LFP
28	Bonneville Power Administration	U.S. Bureau of Reclamation	Bonneville Power Administration	AD
29	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
30	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
31	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	FNO
32	Bonneville Power Administration	Bonneville Power Administration	Yakama Power	AD
33	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
34	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	AD
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 436		Borah/Brady Sub				1
7V11-3	Yellowtail Sub	Sheridan Sub	1	3,914	3,914	2
7V11-3	Yellowtail Sub	Sheridan Sub	1	555	555	3
7V11-7	Various	Various		960	960	4
7V11-8	Various	Various		170	170	5
7V11-8	Various	Various		372	372	6
7V11-7	Various	Various		2,475	2,475	7
7V11	Various	Sheridan Sub	44	24,247	24,247	8
7V11	Various	Sheridan Sub	44	380	380	9
7V11-8	Various	Various		15,177	15,177	10
7V11-8	Various	Various		346	346	11
7V11-7	Various	Various		65,945	65,945	12
7V11-7	Various	Various		525	525	13
7V11-7	Various	Wyodak Substation	50	226,138	226,138	14
7V11-7	Various	Wyodak Substation	50	17,850	17,850	15
R.S. 369	Midpoint Substation	Summer Lake Sub				16
R.S. 237	Various	Various	319	1,230,813	1,230,813	17
R.S. 237	Various	Various	319	113,739	113,739	18
7V11-7		Alvey Substation	56	268,555	268,555	19
7V11-3,4		Alvey Substation	56	28,678	28,678	20
7V11-3,4	Bonneville Power Adm	Gazley Substation	3	22,793	22,793	21
7V11-3	Bonneville Power Adm	Gazley Substation	3	2,319	2,319	22
7V11-3	Bonneville Power Adm	Tieton Substation	1	5,676	5,676	23
7V11-3	Bonneville Power Adm	Tieton Substation	1	933	933	24
7V11-3	McNary Substation	Hinkle Substation	1	702	702	25
7V11-3	McNary Substation	Hinkle Substation	1	137	137	26
7V11-7	USBR Green Springs	Bonneville Power Adm	18	62,183	62,183	27
7V11-7	USBR Green Springs	Bonneville Power Adm	18	4,919	4,919	28
R.S. 368	Malin Substation	Malin Substation		641,015	641,015	29
R.S. 368	Malin Substation	Malin Substation		58,722	58,722	30
7V11-3,4	Bonneville Power Adm		6	32,545	32,545	31
7V11-3,4	Bonneville Power Adm		6	3,099	3,099	32
R.S. 299	Various	Various	211	1,324,863	1,324,863	33
R.S. 299	Various	Various	211	206,938	206,938	34
			3,991	**14,698,484**	**14,582,697**	

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
9,456		20,137	29,593	2
		2,618	2,618	3
	3,720		3,720	4
	993		993	5
	2,260		2,260	6
	14,839		14,839	7
644,061			644,061	8
		58,818	58,818	9
	99,978		99,978	10
		15,318	15,318	11
	377,285		377,285	12
		3,066	3,066	13
1,113,750			1,113,750	14
		101,250	101,250	15
				16
3,876,613		67,947	3,944,560	17
		357,239	357,239	18
1,247,400			1,247,400	19
		113,400	113,400	20
47,684		144,037	191,721	21
		17,849	17,849	22
8,365		908	9,273	23
		775	775	24
1,632		112	1,744	25
		127	127	26
400,950			400,950	27
		36,450	36,450	28
		246,945	246,945	29
		22,450	22,450	30
82,388		85,153	167,541	31
		15,776	15,776	32
953,831		1,024,573	1,978,404	33
		171,168	171,168	34
27,647,272	**12,953,809**	**33,065,431**	**73,666,512**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration			SFP
2	Bonneville Power Administration			NF
3	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
4	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
5	Cargill Power Markets, LLC			NF
6	Cargill Power Markets, LLC			AD
7	Cargill Power Markets, LLC			SFP
8	CEP Funding, LLC	CEP Funding, LLC	CEP Funding, LLC	LFP
9	Constellation Energy Commodities Group			NF
10	Constellation Energy Commodities Group			AD
11	Constellation Energy Commodities Group			SFP
12	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
13	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
14	Cyrq Energy, Inc.			LFP
15	Cyrq Energy, Inc.			AD
16	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
17	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
18	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
19	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
20	Deseret Generation & Trans.	Deseret Generation & Trans.		SFP
21	Eagle Energy Partners			NF
22	Eagle Energy Partners			SFP
23	Enel Cove Fort, LLC	Enel Cove Fort, LLC		LFP
24	Enel Cove Fort, LLC	Enel Cove Fort, LLC		AD
25	Eugene Water & Electric Board			NF
26	Eugene Water & Electric Board			AD
27	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
28	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
29	Foote Creek III, LLC	Foote Creek III, LLC		OS
30	Foote Creek III, LLC	Foote Creek III, LLC		AD
31	Iberdrola Renewables Inc.			NF
32	Iberdrola Renewables Inc.			AD
33	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.		OS
34	Iberdrola Renewables Inc.	Iberdrola Renewables Inc.		AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7V11-7	Various	Various		30,413	30,413	1
7V11-8	Various	Various		246	246	2
7V11-3,4	Cardwell-Merwin		20	115,194	115,194	3
7V11-3,4	Cardwell-Merwin		20	13,688	13,688	4
7V11-8	Various	Various		205,321	205,321	5
7V11-8	Various	Various		2,647	2,647	6
7V11-7	Various	Various		600	600	7
7V11-7	Midpoint Sub	BPAT.PACW	100			8
7V11-8,9,11	Various	Various		10,777	10,777	9
7V11-8,9,11	Various	Various		20	20	10
7V11-5,6,7	Various	Various		85,588	85,588	11
R.S. 234	Swift Unit No. 2	Woodland Sub				12
R.S. 234	Swift Unit No. 2	Woodland Sub				13
7V11-5,6,7,9	South Milford	Mona Substation	11	45,413	45,413	14
7V11-5,6,7,9	South Milford	Mona Substation	11	4,539	4,539	15
R.S. 280	Various	Various	95	481,897	481,897	16
R.S. 280	Various	Various	95	48,654	48,654	17
R.S. 590	Various	Various				18
R.S. 590	Various	Various				19
7V11-7	Various	Various		960	960	20
7V11-8	Various	Various		292	292	21
7V11-7	Various	Various		425	425	22
7V11-7	Enel Cove Fort	Mona Substation				23
7V11-7	Enel Cove Fort	Mona Substation				24
7V11-8	Various	Various		11,171	11,171	25
7V11-8	Various	Various		149	149	26
R.S. 322	Targhee Substation	Goshen Substation		54,545	54,545	27
R.S. 322	Targhee Substation	Goshen Substation				28
S.A. 130	Foote Creek Sub	Various				29
S.A. 130	Foote Creek Sub	Various				30
7V11-8	Various	Various		7,024	7,024	31
7V11-8	Various	Various		192	192	32
7V11-5,6,9,11				2,472	2,472	33
7V11-5,6,9,11				115	115	34
			3,991	**14,698,484**	**14,582,697**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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.
	91,069	2,884	93,953	1
	1,437		1,437	2
285,313		22,125	307,438	3
		31,048	31,048	4
	1,359,671		1,359,671	5
		17,588	17,588	6
	2,325		2,325	7
248,226		575,634	823,860	8
	59,368	33,972	93,340	9
		987	987	10
	1,670	223,125	224,795	11
		107,537	107,537	12
		9,741	9,741	13
245,025		35,230	280,255	14
		25,780	25,780	15
1,949,032		336,357	2,285,389	16
		568,322	568,322	17
		1,640,820	1,640,820	18
		159,190	159,190	19
	3,720		3,720	20
	1,752		1,752	21
	4,077		4,077	22
		50,625	50,625	23
		-81,000	-81,000	24
	65,470		65,470	25
		870	870	26
		138,699	138,699	27
		12,609	12,609	28
		33,168	33,168	29
		3,015	3,015	30
	43,820		43,820	31
		1,150	1,150	32
		320,127	320,127	33
		32,976	32,976	34
27,647,272	**12,953,809**	**33,065,431**	**73,666,512**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Iberdrola Renewables Inc.	Exxon Mobile	Nevada Power Company	LFP
2	Iberdrola Renewables Inc.	Exxon Mobile	Nevada Power Company	AD
3	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
4	Idaho Power Company	Nevada Power Company	Idaho Power Company	LFP
5	Idaho Power Company			NF
6	Idaho Power Company			AD
7	Idaho Power Company			SFP
8	Idaho Power Company			OS
9	Idaho Power Company			FNS
10	Idaho Power Company			OS
11	Idaho Power Company			AD
12	JP Morgan Ventures Energy Corp.			NF
13	JP Morgan Ventures Energy Corp.			AD
14	Los Angeles Dept of Water & Power			NF
15	Los Angeles Dept of Water & Power			AD
16	Macquarie Energy LLC			NF
17	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
18	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
19	Morgan Stanley Capital Group, Inc.			NF
20	Morgan Stanley Capital Group, Inc.			AD
21	Morgan Stanley Capital Group, Inc.			SFP
22	Municipal Energy Agency of Nebraska			NF
23	Nevada Power Company			NF
24	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
25	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
26	NextEra Energy Resources, LLC			NF
27	NextEra Energy Resources, LLC			AD
28	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	FNO
29	Noble Americas Energy Solutions LLC	Bonneville Power Administration	Oregon Direct Access	AD
30	Pacific Gas & Electric Company			OS
31	Pacific Gas & Electric Company			AD
32	Pacific Gas & Electric Company			OS
33	Portland General Electric			SFP
34	Portland General Electric			AD
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7V11-7	Trona Substation	Red Butte/Mona Sub	30	69,735	69,735	1
7V11-7	Trona Substation	Red Butte/Mona Sub	30	7,254	7,254	2
R.S. 427	Goshen Substation	Goshen Substation				3
7V11-7	Red Butte Substation	Borah/Brady Sub	75	8,866	8,866	4
7V11-8	Various	Various		41,000	41,000	5
7V11-8	Various	Various		960	960	6
7V11-7	Various	Various		47,327	47,327	7
R.S. 257	Antelope Substation	Antelope Substation		188,132	188,132	8
R.S. 257	Antelope Substation	Antelope Substation				9
R.S. 203	Jim Bridger Sub	Bridger Pump Station				10
R.S. 203	Jim Bridger Sub	Bridger Pump Station				11
7V11-8,9,11	Various	Various		91,393	91,393	12
7V11-8,9,11	Various	Various		5,040	5,040	13
7V11-8	Various	Various		118,576	118,576	14
7V11-8	Various	Various				15
7V11-8	Various	Various		54	54	16
R.S. 302	Duchesne	Duchesne	3	15,191	15,191	17
R.S. 302	Duchesne	Duchesne	3	1,376	1,376	18
7V11-8	Various	Various		224,302	224,302	19
7V11-8	Various	Various		12,404	12,404	20
7V11-7	Various	Various		15,956	15,956	21
7V11-8	Various	Various		91	91	22
7V11-8	Various	Various		105	105	23
7V11-5,6,9,11	Wallula Substation	Wala-MIDC Path	80	242,862	242,862	24
7V11-5,6,9,11	Wallula Substation	Wala-MIDC Path	80	21,666	21,666	25
7V11-8	Various	Various		1,740	1,740	26
7V11-8	Various	Various				27
7V11-3,4	Bonneville Power Adm	Various	14	87,262	87,262	28
7V11-3,4	Bonneville Power Adm	Various	14	9,792	9,792	29
R.S. 607						30
R.S. 607						31
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				32
7V11-7	Various	Various		3,273	3,273	33
7V11-7	Various	Various		8,235	8,235	34
			3,991	**14,698,484**	**14,582,697**	

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.
668,250			668,250	1
		60,750	60,750	2
				3
670,660			670,660	4
	188,074		188,074	5
		5,606	5,606	6
	646,043	13,795	659,838	7
		67,672	67,672	8
		6,152	6,152	9
		14,927	14,927	10
		1,357	1,357	11
	804,474	1,786	806,260	12
		72,309	72,309	13
	574,866		574,866	14
		584	584	15
	315		315	16
		19,406	19,406	17
		1,623	1,623	18
	1,342,793		1,342,793	19
		80,439	80,439	20
	75,437	12,672	88,109	21
	753		753	22
	613		613	23
1,366,875		1,086,585	2,453,460	24
		255,593	255,593	25
	355,465		355,465	26
		21,538	21,538	27
106,069		16,093	122,162	28
		18,527	18,527	29
		18,333,333	18,333,333	30
		1,666,667	1,666,667	31
		292,930	292,930	32
	13,950		13,950	33
		33,908	33,908	34
27,647,272	**12,953,809**	**33,065,431**	**73,666,512**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
2	Powerex Corporation	Bonneville Power Administration	CAISO	AD
3	Powerex Corporation			NF
4	Powerex Corporation			AD
5	Powerex Corporation			SFP
6	Powerex Corporation			AD
7	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
8	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
9	PPL Energy Plus, LLC			NF
10	PPL Energy Plus, LLC			AD
11	PPL Energy Plus, LLC			SFP
12	Public Service Co. of CO			SFP
13	Puget Sound P&L			NF
14	Rainbow Energy Marketing Corporation			NF
15	Rainbow Energy Marketing Corporation			SFP
16	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	LFP
17	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	AD
18	Shell Energy North America (U.S.) L.P.			NF
19	Sierra Pacific Power Company d/b/a NV			OS
20	Sierra Pacific Power Company d/b/a NV			AD
21	Sierra Pacific Power Company d/b/a NV			NF
22	Southern California Edison			SFP
23	Southern California Edison			AD
24	Southern California Edison			NF
25	Southern California Edison			AD
26	Southern California Edison			OS
27	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
28	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
29	Tenaska Power Services Co.			NF
30	Tenaska Power Services Co.			SFP
31	TransAlta Energy Marketing			NF
32	TransAlta Energy Marketing			AD
33	Tri-State Generation & Trans.			NF
34	Tri-State Generation & Trans.		Tri-State Generation & Trans.	OS
	TOTAL			

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7V11-7	Bonneville Power Adm	CRAG View	80	584,370	584,370	1
7V11-7	Bonneville Power Adm	CRAG View	80	41,858	41,858	2
7V11-8,9,11	Various	Various		378,887	378,887	3
7V11-8	Various	Various		18,620	18,620	4
7V11-5,6,7	Various	Various		36,663	36,663	5
7V11-7	Various	Various				6
R.S. 123	Various	Buffalo Substation				7
R.S. 123	Various	Buffalo Substation				8
7V11-8	Various	Various		10,096	10,096	9
7V11-8	Various	Various		572	572	10
7V11-7	Various	Various		4,139	4,139	11
7V11-7	Various	Various		200	200	12
7V11-8	Various	Various				13
7V11-8	Various	Various		29,890	29,890	14
7V11-7	Various	Various		2,722	2,722	15
7V11-5,6,7,9	Wallula Substation	Wala-MIDC Path	25	60,705	60,705	16
7V11-5,6,7,9	Wallula Substation	Wala-MIDC Path	25	3,707	3,707	17
7V11-8	Various	Various		4,035	4,035	18
R.S. 674	Sigurd Substation	Utah-Nevada Border				19
R.S. 674	Sigurd Substation	Utah-Nevada Border				20
7V11-8	Various	Various		6,138	6,138	21
7V11-5,6,7	Various	Various		1,097	1,097	22
7V11-5,6,7	Various	Various		290	290	23
7V11-8,9,11	Various	Various		311,986	311,986	24
7V11-8,9,11	Various	Various		223	223	25
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				26
7V11-7	Yellowtail Sub	Wyodak Substation	4	17,651	17,651	27
7V11-7	Yellowtail Sub	Wyodak Substation	4	1,528	1,528	28
7V11-8	Various	Various		18,844	18,844	29
7V11-7	Various	Various		65	65	30
7V11-8	Various	Various		36,227	36,227	31
7V11-8	Various	Various		180	180	32
7V11-8	Various	Various		14,641	14,641	33
R.S. 123	Various	Various	23	131,860	131,860	34
			3,991	**14,698,484**	**14,582,697**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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.
1,747,279			1,747,279	1
		162,000	162,000	2
	2,934,730	33,626	2,968,356	3
		111,616	111,616	4
	78,210	68,900	147,110	5
		-18,399	-18,399	6
		290	290	7
		14	14	8
	72,950		72,950	9
		3,346	3,346	10
	25,488		25,488	11
	1,168		1,168	12
	6		6	13
	95,469		95,469	14
	54,699	4,060	58,759	15
556,875		59,607	616,482	16
		54,965	54,965	17
	28,131		28,131	18
		62,654	62,654	19
		12,531	12,531	20
	36,836		36,836	21
	9,450	1,509	10,959	22
		7,290	7,290	23
	2,059,926	295,685	2,355,611	24
		75,954	75,954	25
		292,930	292,930	26
89,100			89,100	27
		8,100	8,100	28
	143,882		143,882	29
	2,705		2,705	30
	281,346		281,346	31
		1,051	1,051	32
	96,221		96,221	33
117,754			117,754	34
27,647,272	**12,953,809**	**33,065,431**	**73,666,512**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
2	Tri-State Generation & Trans.		Tri-State Generation & Trans.	SFP
3	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
4	Tri-State Generation & Trans.		Tri-State Generation & Trans.	AD
5	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
6	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
7	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
8	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	AD
9	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
10	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
11	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
12	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
13	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
14	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
15	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	OS
16	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	AD
17	Western Area Power Administration	Western Area Power Administration		OS
18	Western Area Power Administration	Western Area Power Administration		AD
19	Western Area Power Administration	Western Area Power Administration		OS
20	Western Area Power Administration	Western Area Power Administration		AD
21	Western Area Power Administration	Western Area Power Administration		NF
22	Western Area Power Administration	Western Area Power Administration		SFP
23	Western Area Power Administration	Western Area Power Administration		OS
24	Western Area Power Administration	Western Area Power Administration		AD
25	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
26	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD
27	Accrual			
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
R.S. 123	Various	Various	23	14,530	14,530	1
7V11-7	Various	Various		9,940	9,940	2
7V11-3,4	Dave Johnston Sub	Thermopolis Sub	18	99,842	99,842	3
7V11-3,4	Dave Johnston Sub	Thermopolis Sub		10,377	10,377	4
7V11-3	Walla Walla Sub	Burbank Pumps	1	2,277	2,277	5
7V11-3	Walla Walla Sub	Burbank Pumps	1			6
R.S. 67	Redmond Sub	Crooked River Pumps	4	9,057	9,057	7
R.S. 67	Redmond Sub	Crooked River Pumps	4			8
R.S. 286	Various	Various		14,019	14,019	9
R.S. 286	Various	Various		939	939	10
R.S. 297	Various	Various	362	2,707,686	2,707,686	11
R.S. 297	Various	Various	362	276,212	276,212	12
R.S. 637	Various	Various	105	498,829	498,829	13
R.S. 637	Various	Various	105	49,381	49,381	14
R.S. 591	Pelton Reregulating	Round Butte Sub		85,647	85,647	15
R.S. 591	Pelton Reregulating	Round Butte Sub		8,195	8,195	16
R.S. 262	Various	Various	331	1,905,327	1,798,559	17
R.S. 262	Various	Various	331	159,252	150,233	18
R.S. 263	Various	Various		115,654	115,654	19
R.S. 263	Various	Various		7,608	7,608	20
7V11-8	Various	Various		67,050	67,050	21
7V11-7	Various	Various		112,392	112,392	22
R.S. 664	Dave Johnston Sub	Various		68,629	68,629	23
R.S. 664	Dave Johnston Sub	Various		36,864	36,864	24
7V11	Wyoming Distribution	Wyoming Distribution	1	8,962	8,962	25
7V11	Wyoming Distribution	Wyoming Distribution	1	4	4	26
						27
						28
						29
						30
						31
						32
						33
						34
			3,991	**14,698,484**	**14,582,697**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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.
		3,809	3,809	1
	50,625		50,625	2
261,145		58,276	319,421	3
		25,313	25,313	4
4,054		9,229	13,283	5
		1,168	1,168	6
11,036			11,036	7
		-682	-682	8
		13,167	13,167	9
		939	939	10
6,745,146		766,609	7,511,755	11
		670,058	670,058	12
2,071,697		98,395	2,170,092	13
		171,988	171,988	14
		109,725	109,725	15
		9,975	9,975	16
2,099,021		550,000	2,649,021	17
		223,897	223,897	18
		70,951	70,951	19
		5,825	5,825	20
	327,153		327,153	21
	457,078		457,078	22
	61,499		61,499	23
		2,517	2,517	24
18,585		36,638	55,223	25
		4,940	4,940	26
		102,018	102,018	27
				28
				29
				30
				31
				32
				33
				34
27,647,272	**12,953,809**	**33,065,431**	**73,666,512**	

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

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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

Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Agreement between PacifiCorp and Arizona Public Service Company ("Restated TSA"), Rate Schedule 436). The contract terminates October 31, 2020. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form No. 1.

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

Glenn Canyon/Four Corners Substation.

Schedule Page: 328 Line No.: 2 Column: d

Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 505) terminating no earlier than 12 months from notice by customer.

Schedule Page: 328 Line No.: 2 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and frequency response.

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

Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 505) terminating no earlier than 12 months from notice by customer.

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

Distribution voltage service charge. Primary delivery service. Regulation and frequency response. December 2010 service.

Schedule Page: 328 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 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: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BLACK HILLS/COLORADO ELECTRIC UTILITY COMPANY" ON PAGES 328 - 330:
Complete name is Black Hills/Colorado Electric Utility Company, L.P.

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.: 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

Non-Firm or Short-Term Firm Transmission Service under the Open Access Transmission Tariff between various parties and points.

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

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

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

Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 9 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 9 Column: d
Network Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 347) terminating on December 31, 2017.

Schedule Page: 328 Line No.: 9 Column: m
December 2010 service.

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.: 11 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 11 Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 11 Column: m
Unauthorized use of transmission service from 2009. December 2010 service.

Schedule Page: 328 Line No.: 12 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 12 Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 13 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 13 Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 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 Line No.: 13 Column: m
December 2010 service.

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 (1st Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 15 Column: b
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328 Line No.: 15 Column: d
Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 15 Column: m
December 2010 service.

Schedule Page: 328 Line No.: 16 Column: b

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 16 Column: c

Capacity exchanged and operated by each transmission provider with no receipt or delivery of energy.

Schedule Page: 328 Line No.: 16 Column: d

Legacy Contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form No. 1.

Schedule Page: 328 Line No.: 17 Column: d

Legacy Contract (2nd Revised Rate Schedule 237) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 17 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge.

Schedule Page: 328 Line No.: 18 Column: d

Legacy Contract (2nd Revised Rate Schedule 237) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract subject to termination upon the earlier of the termination of the "Exchange Agreement" between PacifiCorp and BPA or the time of the termination of all deliveries as defined in the agreement.

Schedule Page: 328 Line No.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge. December 2010 service.

Schedule Page: 328 Line No.: 19 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 19 Column: f

Lost Creek Hydro Plant.

Schedule Page: 328 Line No.: 20 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 20 Column: f

Lost Creek Hydro Plant.

Schedule Page: 328 Line No.: 20 Column: m

December 2010 service.

Schedule Page: 328 Line No.: 21 Column: d

Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (4th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 21 Column: f

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BONNEVILLE POWER ADM" ON PAGES 328 - 330: Complete name is Bonneville Power Administration.

Schedule Page: 328 Line No.: 21 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and 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 (4th Revised Service Agreement 229) terminating on September 30, 2028.

Schedule Page: 328 Line No.: 22 Column: m

Distribution voltage service charge. Primary delivery service. Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328 Line No.: 23 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.: 23 Column: d

Network Transmission and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 23 Column: m

Regulation and frequency response.

Schedule Page: 328 Line No.: 24 Column: d

Network Transmission and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 24 Column: m

Regulation and frequency response. December 2010 service.

Schedule Page: 328 Line No.: 25 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UMATILLA ELEC & COLUMBIA" ON PAGES 328 - 330:
Complete name is Umatilla Electric Coop. and Columbia Basin Electric Coop.

Schedule Page: 328 Line No.: 25 Column: d

Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 25 Column: m

Regulation and frequency response.

Schedule Page: 328 Line No.: 26 Column: d

Network Transmission Service Delivery Service under the Open Access Transmission Tariff (Service Agreement 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 26 Column: m

Regulation and frequency response. December 2010 service.

Schedule Page: 328 Line No.: 27 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "U.S. BUREAU OF RECLAMATION" ON PAGES 328 - 330:
Complete name is United States Department of the Interior Bureau of Reclamation.

Schedule Page: 328 Line No.: 27 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 28 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 28 Column: m

December 2010 service.

Schedule Page: 328 Line No.: 29 Column: d

Legacy Contract (5th Revised Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 29 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328 Line No.: 30 Column: d

Legacy Contract (5th Revised Rate Schedule 368) executed between PacifiCorp and Bonneville Power Administration for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Subject to termination upon mutual agreement.

Schedule Page: 328 Line No.: 30 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. December 2010 service.

Schedule Page: 328 Line No.: 31 Column: d
Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 328) terminating on July 31, 2012.

Schedule Page: 328 Line No.: 31 Column: g
White Swan/Toppenish Substation.

Schedule Page: 328 Line No.: 31 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328 Line No.: 32 Column: d
Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 328) terminating on July 31, 2012.

Schedule Page: 328 Line No.: 32 Column: g
White Swan/Toppenish Substation.

Schedule Page: 328 Line No.: 32 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328 Line No.: 33 Column: d
Legacy Contract (1st Revised Rate Schedule 299) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination in June 2011.

Schedule Page: 328 Line No.: 33 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge. Charges for scheduling and operating reserves.

Schedule Page: 328 Line No.: 34 Column: d
Legacy Contract (1st Revised Rate Schedule 299) executed between PacifiCorp and Bonneville Power Administration ("BPA") for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Contract terminates with three years notice by BPA or five years notice by PacifiCorp. PacifiCorp provided notice of termination in June 2011.

Schedule Page: 328 Line No.: 34 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use/direct assigned facilities charge. Charges for scheduling and operating reserves. December 2010 service.

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.: 1 Column: m
Penalty revenues covering imbalance charges per Schedules 4 and 9.

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.: 3 Column: d

Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 370) terminating on December 7, 2012 or with six months written notice.

Schedule Page: 328.1 Line No.: 3 Column: g

Chelatchie/View 115kV.

Schedule Page: 328.1 Line No.: 3 Column: m

Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 4 Column: d

Network Transmission Service under the Open Access Transmission Tariff (Service Agreement 370) terminating on December 7, 2012 or with six months written notice.

Schedule Page: 328.1 Line No.: 4 Column: g

Chelatchie/View 115kV.

Schedule Page: 328.1 Line No.: 4 Column: m

Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

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: 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: m

December 2010 service.

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.: 8 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 662) terminating May 31, 2019.

Schedule Page: 328.1 Line No.: 8 Column: m

Transmission resales, amount paid by seller.

Schedule Page: 328.1 Line No.: 9 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.: 9 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 9 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 9 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 10 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 10 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.1 Line No.: 11 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 11 Column: m

Charges for spinning and/or supplemental reserves. Transmission resales, purchase of point-to-point transmission.

Schedule Page: 328.1 Line No.: 12 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.: 12 Column: d

Legacy Contract (Rate Schedule 234) providing for transmission and operation of Swift Hydroelectric Plant No. 2, and for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement may be terminated subsequent to the termination of the Power Contract as defined in the agreement by the customer providing at least six months written notice and specifying the date on which the customer will assume responsibility of operations and maintenance of Swift Hydroelectric Plant No. 2.

Schedule Page: 328.1 Line No.: 12 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 13 Column: d

Legacy Contract (Rate Schedule 234) providing for transmission and operation of Swift Hydroelectric Plant No. 2, and for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement may be terminated subsequent to the termination of the Power Contract as defined in the agreement by the customer providing at least six months written notice and specifying the date on which the customer will assume responsibility of operations and maintenance of Swift Hydroelectric Plant No. 2.

Schedule Page: 328.1 Line No.: 13 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. December 2010 service.

Schedule Page: 328.1 Line No.: 14 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

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 (1st Revised

Service Agreement 568) terminating April 30, 2029.

Schedule Page: 328.1 Line No.: 14 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9.

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

Point-to-Point Transmission Service under the Open Access Transmission Tariff (1st Revised Service Agreement 568) terminating April 30, 2029.

Schedule Page: 328.1 Line No.: 15 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.1 Line No.: 16 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET GENERATION & TRANS." ON PAGES 328 - 330:

Complete name is Deseret Generation and Transmission Co-operative.

Schedule Page: 328.1 Line No.: 16 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 16 Column: m

Scheduling and load following charges. Distribution voltage service charge. Charges for spinning and/or supplemental reserves.

Schedule Page: 328.1 Line No.: 17 Column: d

Legacy Contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (3rd Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 17 Column: m

Scheduling and load following charges. Distribution voltage service charge. Charges for spinning and/or supplemental reserves including spinning and/or supplemental reserves covering 2009 to 2010. December 2010 service.

Schedule Page: 328.1 Line No.: 18 Column: d

Control Area Services Agreement (Rate Schedule 590) for charges associated with providing control area support and ancillary services. Agreement terminated and was replaced by the 1st Amended and Restated Control Area Services Agreement (Rate Schedule 590 Rev. 1), which incorporates provisions in the previous agreement. Agreement terminated January 31, 2012.

Schedule Page: 328.1 Line No.: 18 Column: m

Charges for spinning and/or supplemental reserves. Regulation and frequency response. Meter interrrogation charge. Charges for control area services.

Schedule Page: 328.1 Line No.: 19 Column: d

Control Area Services Agreement (Rate Schedule 590) for charges associated with providing control area support and ancillary services. Agreement terminated and was replaced by the 1st Amended and Restated Control Area Services Agreement (Rate Schedule 590 Rev. 1), which incorporates provisions in the previous agreement. Agreement terminated January 31, 2012.

Schedule Page: 328.1 Line No.: 19 Column: m

Charges for spinning and/or supplemental reserves. Regulation and frequency response. Meter interrrogation charge. Charges for control area services. December 2010 service.

Schedule Page: 328.1 Line No.: 20 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 21 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 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: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 23 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff,(1st Revised Service Agreement 706) deferred until November 1, 2012. Terminating April 30, 2043.

Schedule Page: 328.1 Line No.: 23 Column: m

Extension of Commencement Date Fee.

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

Point-to-Point Transmission Service under the Open Access Transmission Tariff,(1st Revised Service Agreement 706) deferred until November 1, 2012. Terminating April 30, 2043.

Schedule Page: 328.1 Line No.: 24 Column: m

Partial refund of Extension of Commencement Date Fee.

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: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 26 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 26 Column: m

December 2010 service.

Schedule Page: 328.1 Line No.: 27 Column: d

Legacy Contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.1 Line No.: 27 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.1 Line No.: 28 Column: d

Legacy Contract (Rate Schedule 322) executed between PacifiCorp and Fall River Rural

Electric Cooperative for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating on July 31, 2027.

Schedule Page: 328.1 Line No.: 28 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. December 2010 service.

Schedule Page: 328.1 Line No.: 29 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 29 Column: d

Service Agreement 130 executed between PacifiCorp and Foote Creek III, LLC (Seawest) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating July 2014.

Schedule Page: 328.1 Line No.: 29 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.1 Line No.: 30 Column: c

PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.

Schedule Page: 328.1 Line No.: 30 Column: d

Service Agreement 130 executed between PacifiCorp and Foote Creek III, LLC (Seawest) for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating July 2014.

Schedule Page: 328.1 Line No.: 30 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2010 service.

Schedule Page: 328.1 Line No.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 32 Column: m

December 2010 service.

Schedule Page: 328.1 Line No.: 33 Column: c

Iberdrola Renewables Inc. and Utah Associated Municipal Power Systems.

Schedule Page: 328.1 Line No.: 33 Column: d

Ancillary Services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 33 Column: f

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.1 Line No.: 33 Column: g

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.1 Line No.: 33 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.1 Line No.: 34 Column: c

Iberdrola Renewables Inc. and Utah Associated Municipal Power Systems.

Schedule Page: 328.1 Line No.: 34 Column: d

Ancillary Services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.1 Line No.: 34 Column: f

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.1 Line No.: 34 Column: g

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.1 Line No.: 34 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.2 Line No.: 1 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 279). Agreement terminating April 30, 2014.

Schedule Page: 328.2 Line No.: 2 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 279). Agreement terminating April 30, 2014.

Schedule Page: 328.2 Line No.: 2 Column: m

December 2010 service.

Schedule Page: 328.2 Line No.: 3 Column: d

Legacy Contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 (“Goshen Agreement”)). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form No. 1.

Schedule Page: 328.2 Line No.: 4 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 212) terminating May 31, 2014.

Schedule Page: 328.2 Line No.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 6 Column: m

December 2010 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.: 7 Column: m

Transmission resales, amount paid by seller.

Schedule Page: 328.2 Line No.: 8 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 8 Column: d

Legacy Contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the Idaho Power Company/United States Department of Energy Supply Agreement.

Schedule Page: 328.2 Line No.: 8 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 9 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 9 Column: d

Legacy Contract (Rate Schedule 257) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Antelope Substation terminating coterminous with the Idaho Power Company/United States Department of Energy Supply Agreement.

Schedule Page: 328.2 Line No.: 9 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2010 service.

Schedule Page: 328.2 Line No.: 10 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 10 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 10 Column: d

Legacy Contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Jim Bridger Pump. Agreement terminates upon 12-month written notice.

Schedule Page: 328.2 Line No.: 10 Column: m

Charge for transmission servcie over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 11 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 11 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 11 Column: d

Legacy Contract (Rate Schedule 203) executed between PacifiCorp and Idaho Power Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (Service Agreement 203) for the Jim Bridger Pump. Agreement terminates upon 12-month written notice.

Schedule Page: 328.2 Line No.: 11 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2010 service.

Schedule Page: 328.2 Line No.: 12 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "JP MORGAN VENTURES ENERGY CORP." ON PAGES 328 - 330:
Complete name is JP Morgan Ventures Energy Corporation.

Schedule Page: 328.2 Line No.: 12 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 12 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 12 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 13 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 13 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 13 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.2 Line No.: 14 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "LOS ANGELES DEPT OF WATER & POWER" ON PAGES 328 - 330:
Complete name is Los Angeles Department of Water and Power.

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 2010 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.: 17 Column: d

Legacy Contract (2nd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake Electric Association for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2011, by providing two years' written notice.

Schedule Page: 328.2 Line No.: 17 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.2 Line No.: 18 Column: d

Legacy Contract (2nd Revised Rate Schedule 302) executed between PacifiCorp and Moon Lake

Electric Association for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Either party may terminate the agreement at any time after October 14, 2011, by providing two years' written notice.

Schedule Page: 328.2 Line No.: 18 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. December 2010 service.

Schedule Page: 328.2 Line No.: 19 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 19 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.: 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.: 20 Column: m

December 2010 service.

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.: 21 Column: m

Transmission resales, purchase of point-to-point transmission.

Schedule Page: 328.2 Line No.: 22 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 23 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 24 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.: 24 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 626) assignment from Seattle City & Light, terminating December 31, 2011. Customer executed extension of service through assignment from Seattle City & Light (Service Agreement 708) through October 31, 2014.

Schedule Page: 328.2 Line No.: 24 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Transmission resales, amount paid by seller.

Schedule Page: 328.2 Line No.: 25 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (Service Agreement 626) assignment from Seattle City & Light, terminating December 31, 2011. Customer executed extension of service through assignment from Seattle City & Light (Service Agreement 708) through October 31, 2014.

Schedule Page: 328.2 Line No.: 25 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 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 signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 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: 328.2 Line No.: 27 Column: m

December 2010 service.

Schedule Page: 328.2 Line No.: 28 Column: d

Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 299). Service provided pursuant to rules & regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 28 Column: m

Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.2 Line No.: 29 Column: d

Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 299). Service provided pursuant to rules & regulations of Oregon Direct Access. Agreement termination upon notification pursuant to Oregon Direct Access and Open Access Transmission Tariff.

Schedule Page: 328.2 Line No.: 29 Column: m

Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.2 Line No.: 30 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 30 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 30 Column: d

Legacy Contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.2 Line No.: 30 Column: f

Malin to Indian Springs line segment.

Schedule Page: 328.2 Line No.: 30 Column: g

Malin to Indian Springs line segment.

Schedule Page: 328.2 Line No.: 30 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 31 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 31 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 31 Column: d

Legacy Contract (Rate Schedule 607) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities (Malin to Round Mountain) and/or subject to a sole-use or facilities charge. Terminating December 31, 2017. See PacifiCorp Docket No. ER07-882, et al, Settlement Agreement, Appendix 2 (filed November 20, 2007).

Schedule Page: 328.2 Line No.: 31 Column: f

Malin to Indian Springs line segment.

Schedule Page: 328.2 Line No.: 31 Column: g

Malin to Indian Springs line segment.

Schedule Page: 328.2 Line No.: 31 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2010 service.

Schedule Page: 328.2 Line No.: 32 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 32 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 32 Column: d

Legacy Contract (Rate Schedule 298) executed between PacifiCorp and Pacific Gas & Electric Company for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge (phase shifting transformers at Sigurd-Glen Canyon 230-kV transmission line and Pinto-Four Corners 345-kV transmission line). Terminating February 12, 2020.

Schedule Page: 328.2 Line No.: 32 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.2 Line No.: 33 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PORTLAND GENERAL ELECTRIC" ON PAGES 328 - 330:
Complete name is Portland General Electric Company.

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.: 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: 328.2 Line No.: 34 Column: m

December 2010 service.

Schedule Page: 328.3 Line No.: 1 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CAISO" ON PAGES 328 - 330:
Complete name is California Independent System Operator Corporation.

Schedule Page: 328.3 Line No.: 1 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 2 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (5th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 2 Column: m

December 2010 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.: 3 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

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.: 4 Column: m

December 2010 service.

Schedule Page: 328.3 Line No.: 5 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 5 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 5 Column: m

Charges for spinning and/or supplemental reserves. Transmission resales, purchase of point-to-point transmission.

Schedule Page: 328.3 Line No.: 6 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 6 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 6 Column: m

Refund of spinning and supplemental reserves for 2009 and 2010.

Schedule Page: 328.3 Line No.: 7 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SHERDIAN-JOHNSON RURAL ELECT." ON PAGES 328 - 330:
Complete name is Sheridan-Johnson Rural Electric Association.

Schedule Page: 328.3 Line No.: 7 Column: d

Agreement providing for transmission service from Western Area Power Administration's Casper Substation in Wyoming and Yellowtail Substation in Montana to Sheridan-Johnson Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.3 Line No.: 7 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 8 Column: d

Agreement providing for transmission service from Western Area Power Administration's Casper Substation in Wyoming and Yellowtail Substation in Montana to Sheridan-Johnson Rural Electric Association's load at PacifiCorp's Buffalo Substation in Wyoming.

Schedule Page: 328.3 Line No.: 8 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2010 service.

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.: 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.: 10 Column: m

December 2010 service.

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.: 12 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUBLIC SERVICE CO. OF CO" ON PAGES 328 - 330: Complete name is Public Service Company of Colorado.

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: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "PUGET SOUND P&L" ON PAGES 328 - 330: Complete name is Puget Sound Power & Light Company.

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.: 14 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 14 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 15 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 15 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 15 Column: m

Transmission resales, purchase of point-to-point transmission.

Schedule Page: 328.3 Line No.: 16 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th Revised Service Agreement 289) terminating October 31, 2014.

Schedule Page: 328.3 Line No.: 16 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.3 Line No.: 17 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (8th Revised Service Agreement 289) terminating October 31, 2014.

Schedule Page: 328.3 Line No.: 17 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

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.: 19 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SIERRA PACIFIC POWER COMPANY d/b/a NV" ON PAGES 328 - 330:
Complete name is Sierra Pacific Power Company d/b/a NV Energy.

Schedule Page: 328.3 Line No.: 19 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 19 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 19 Column: d

Legacy Contract (Rate Schedule 674) executed betweeen PacifiCorp and Sierra Pacific Power Company d/b/a NV Energy for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating May 19, 2016.

Schedule Page: 328.3 Line No.: 19 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 20 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 20 Column: d

Legacy Contract (Rate Schedule 674) executed betweeen PacifiCorp and Sierra Pacific Power Company d/b/a NV Energy for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating May 19, 2016.

Schedule Page: 328.3 Line No.: 20 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. November and December 2010 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: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "SOUTHERN CALIFORNIA EDISON" ON PAGES 328 - 330:
Complete name is Southern California Edison Company.

Schedule Page: 328.3 Line No.: 22 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 22 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 22 Column: m

Charges for spinning and/or supplemental reserves.

Schedule Page: 328.3 Line No.: 23 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 23 Column: m

Charges for spinning and/or supplemental reserves. December 2010 service.

Schedule Page: 328.3 Line No.: 24 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 24 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.3 Line No.: 25 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 25 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 25 Column: m

Charges for spinning and/or supplemental reserves. Unauthorized use of transmission service(including refunds). Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.3 Line No.: 26 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 26 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 26 Column: d

Use of Facilities Agreement-Phase Shifting Transformers at Sigurd-Glen Canyon 230-kV transmission line and Pinto-Four Corners 345-kV transmission line (Rate Schedule 298), terminating February 12, 2020.

Schedule Page: 328.3 Line No.: 26 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge.

Schedule Page: 328.3 Line No.: 27 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (9th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.3 Line No.: 28 Column: d

Point-to-Point Transmission Service under the Open Access Transmission Tariff (9th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.3 Line No.: 28 Column: m

December 2010 service.

Schedule Page: 328.3 Line No.: 29 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 29 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 30 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 30 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 31 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 31 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 32 Column: b

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 32 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 32 Column: m

December 2010 service.

Schedule Page: 328.3 Line No.: 33 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "TRI-STATE GENERATION & TRANS." ON PAGES 328 - 330:
Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 328.3 Line No.: 33 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: c
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 34 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 34 Column: d
Legacy Contract (2nd Revised Rate Schedule 123) executed between PacifiCorp and Tri-State Generation and Transmission Association, Inc. for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating October 1, 2014.

Schedule Page: 328.4 Line No.: 1 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 1 Column: d
Legacy Contract (2nd Revised Rate Schedule 123) executed between PacifiCorp and Tri-State Generation and Transmission Association, Inc. for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Terminating October 1, 2014.

Schedule Page: 328.4 Line No.: 1 Column: m
December 2010 service.

Schedule Page: 328.4 Line No.: 2 Column: b
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: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 3 Column: d
Network Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 3 Column: m
Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.4 Line No.: 4 Column: b
Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 4 Column: d
Network Transmission Service under the Open Access Transmission Tariff (3rd Revised Service Agreement 628) terminating on June 30, 2021.

Schedule Page: 328.4 Line No.: 4 Column: m
Regulation and frequency response. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2010 service.

Schedule Page: 328.4 Line No.: 5 Column: d
Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.4 Line No.: 5 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response.

Schedule Page: 328.4 Line No.: 6 Column: d
Network Transmission Service and Distribution Delivery Service under the Open Access Transmission Tariff (Service Agreement 506) terminating upon written notification.

Schedule Page: 328.4 Line No.: 6 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response. December 2010 service.

Schedule Page: 328.4 Line No.: 7 Column: d

Legacy Contract (3rd Amended Rate Schedule 67) executed between PacifiCorp and United States Department of the Interior Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement termination with one year written notice.

Schedule Page: 328.4 Line No.: 8 Column: d

Legacy Contract (3rd Amended Rate Schedule 67) executed between PacifiCorp and United States Department of the Interior Bureau of Reclamation Crooked River Irrigation District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. Agreement termination with one year written notice.

Schedule Page: 328.4 Line No.: 8 Column: m

2010 Transmission usage refund.

Schedule Page: 328.4 Line No.: 9 Column: c

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "WEBER BASIN WATER CONSERV." ON PAGES 328 - 330:
Complete name is Weber Basin Water Conservancy District.

Schedule Page: 328.4 Line No.: 9 Column: d

Legacy Contract (2nd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior Bureau of Reclamation for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138 kV. Agreement terminates any time after April 1, 2040 with four years written notification.

Schedule Page: 328.4 Line No.: 9 Column: m

Energy consumption charge for deliveries at and below 138 kV.

Schedule Page: 328.4 Line No.: 10 Column: d

Legacy Contract (2nd Revised Rate Schedule 286) executed between PacifiCorp and United States Bureau of Reclamation Weber Basin Water Conservancy District for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for energy deliveries at and below 138 kV. Agreement termination any time after April 1, 2040 with four years written notification.

Schedule Page: 328.4 Line No.: 10 Column: m

Energy consumption charge for deliveries at and below 138 kV. December 2010 service.

Schedule Page: 328.4 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "UTAH ASSOCIATED MUNICIPAL POWER" ON PAGES 328 - 330:
Complete name is Utah Associated Municipal Power Systems.

Schedule Page: 328.4 Line No.: 11 Column: d

Legacy Contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 11 Column: m

Charge for scheduling and load following. Charges for spinning and/or supplemental reserves. Distribution voltage service charge.

Schedule Page: 328.4 Line No.: 12 Column: d

Legacy Contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 12 Column: m

Charge for scheduling and load following. Charges for spinning and/or supplemental reserves. Distribution voltage service charge. December 2010 service.

Schedule Page: 328.4 Line No.: 13 Column: d

Legacy Contract (1st Revised Rate Schedule 637) executed between PacifiCorp and Utah Municipal Power Agency for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 13 Column: m

Charges for scheduling and load following.

Schedule Page: 328.4 Line No.: 14 Column: d

Legacy Contract (1st Revised Rate Schedule 637) executed between PacifiCorp and Utah Municipal Power Agency for transmission service over agreed-upon facilities (Amended and Restated Transmission Service and Operating Agreement). Subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 14 Column: m

Charges for scheduling and load following. December 2010 service.

Schedule Page: 328.4 Line No.: 15 Column: d

Legacy Contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Agreement terminating January 31, 2032.

Schedule Page: 328.4 Line No.: 15 Column: m

Charge for transmission service over agreed-upon facilties and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract.

Schedule Page: 328.4 Line No.: 16 Column: d

Legacy Contract (Rate Schedule 591) executed between PacifiCorp and Warm Springs Power Enterprises for transmission service over agreed-upon facilities and/or subject to sole-use or facilities charge. Agreement terminating January 31, 2032.

Schedule Page: 328.4 Line No.: 16 Column: m

Charge for transmission service over agreed-upon facilties and/or subject to a sole-use or facilities charge based on a capacity factor and/or proportional use as defined in the contract. December 2010 service.

Schedule Page: 328.4 Line No.: 17 Column: c

Various Western Area Power Administration customers in PacifiCorp's Control Area.

Schedule Page: 328.4 Line No.: 17 Column: d

Legacy Contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 17 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.4 Line No.: 18 Column: c

Various Western Area Power Administration customers in PacifiCorp's Control Area.

Schedule Page: 328.4 Line No.: 18 Column: d

Legacy Contract (Rate Schedule 262) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to preferential customers for deliveries of Colorado River Storage Project power and energy. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 18 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement. December 2010 service.

Schedule Page: 328.4 Line No.: 19 Column: c

Various Western Area Power Administration customers in PacifiCorp's Control Area.

Schedule Page: 328.4 Line No.: 19 Column: d

Legacy Contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 19 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.4 Line No.: 20 Column: c

Various Western Area Power Administration customers in PacifiCorp's Control Area.

Schedule Page: 328.4 Line No.: 20 Column: d

Legacy Contract (Rate Schedule 263) executed between PacifiCorp and Western Area Power Administration for transmission and interconnection service over agreed-upon facilities and/or subject to a sole-use or facilities charge for load service to low voltage customers for deliveries of power and energy from Salt Lake City Area Integrated Projects, including the Colorado River Storage Projects, to certain municipalities at service below 138kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 20 Column: m

Charges for low-voltage transmission of power and energy. December 2010 service.

Schedule Page: 328.4 Line No.: 21 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 22 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 23 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 23 Column: d

Legacy Contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form No. 1.

Schedule Page: 328.4 Line No.: 24 Column: c

Various signatories to the 7th Revised Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 24 Column: d

Legacy Contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also FERC Account 565, Transmission of electricity by others, page 332 of this Form No. 1.

Schedule Page: 328.4 Line No.: 24 Column: m

December 2010 service.

Schedule Page: 328.4 Line No.: 25 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 175).

Schedule Page: 328.4 Line No.: 25 Column: m

Distribution voltage service charge. Primary delivery service.

Schedule Page: 328.4 Line No.: 26 Column: d

Evergreen Network Transmission Service under the Open Access Transmission Tariff (2nd Revised Service Agreement 175).

Schedule Page: 328.4 Line No.: 26 Column: m

Distribution voltage service charge. Primary delivery service. December 2010 service.

Schedule Page: 328.4 Line No.: 27 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 FERC Account 456.1, Revenues from transmission of electricity of others, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	AD			-17			-17
2	Arizona Public Service	LFP	321,682	321,682	1,113,528			1,113,528
3	Arizona Public Service	NF	46,297	46,297	229,279			229,279
4	Arizona Public Service	OS			-236		5,843	5,607
5	Arizona Public Service	OS						
6	Arizona Public Service	SFP	46,633	46,633	156,040			156,040
7	Ashland, City of	FNS	1,808	1,808		16,893		16,893
8	Avista Corporation	FNS	56,279	59,445	228,253			228,253
9	Avista Corporation	NF	110,440	110,440	570,509			570,509
10	Basin Elect. Power Coop	NF	87,327	87,327		130,117		130,117
11	Big Horn Rural Electric	OLF					189,925	189,925
12	Bonneville Power Admin.	AD			41,832		-1,048	40,784
13	Bonneville Power Admin.	FNS			5,803,565			5,803,565
14	Bonneville Power Admin.	LFP	5,485,314	5,485,314	53,528,422			53,528,422
15	Bonneville Power Admin.	NF	533,654	533,654		2,310,228		2,310,228
16	Bonneville Power Admin.	OLF	2,571,894	2,783,711	30,771,444		110,760	30,882,204
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin.	OS	15,131	15,131		46,676	4,419,061	4,465,737
2	Bonneville Power Admin.	OS						
3	Bonneville Power Admin.	SFP	54,376	54,376		94,616		94,616
4	CA Ind. Sys. Operator	AD				-141,583	-27,165	-168,748
5	CA Ind. Sys. Operator	OS					1,971,448	1,971,448
6	CA Ind. Sys. Operator	SFP	408,125	408,125		2,631,930		2,631,930
7	Deseret Gen & Trans	AD	1,503	1,503	11,012			11,012
8	Deseret Gen & Trans	LFP	218,291	218,291	4,209,870			4,209,870
9	Deseret Gen & Trans	NF	329,460	329,460	2,033,478			2,033,478
10	El Paso Elect. Co.	AD	-300	-300	-226			-226
11	Flathead Elect. Coop.	OS					51,696	51,696
12	Hermiston Generating Co	OS					178,852	178,852
13	Idaho Power Company	AD			-6,683		100,664	93,981
14	Idaho Power Company	FNS			8,834			8,834
15	Idaho Power Company	LFP	2,903,953	2,974,739	6,271,673			6,271,673
16	Idaho Power Company	NF	114,339	206,917	618,221			618,221
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Idaho Power Company	OS			-5,909		11,873,518	11,867,609
2	Idaho Power Company	OS						
3	Idaho Power Company	SFP	9,000	9,000	24,013			24,013
4	Moon Lake Elect. Assoc.	AD					-62,123	-62,123
5	Moon Lake Elect. Assoc.	FNS					260,381	260,381
6	Morgan City Corporation	AD	81	81		848		848
7	Morgan Stanley Capital	SFP			-144,285			-144,285
8	Nevada Power Company	NF	21,576	21,576	59,254			59,254
9	Nevada Power Company	OS					51,307	51,307
10	Nevada Power Company	SFP	102,336	102,336	226,733			226,733
11	NorthWestern Corp.	NF	13,430	13,430	58,147			58,147
12	NorthWestern Corp.	OS					4,181	4,181
13	NorthWestern Corp.	SFP	5,832	5,832	25,248			25,248
14	Platte River Power	LFP	189,427	189,427	966,000			966,000
15	Platte River Power	NF	160	160	600			600
16	Platte River Power	OS					12,388	12,388
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Portland Gen. Electric	AD	600	600	500		10	510
2	Portland Gen. Electric	OLF					880	880
3	Powerex Corporation	SFP			-1,618,092			-1,618,092
4	Public Service Co of CO	LFP	99,874	103,789	919,899			919,899
5	Public Service Co of NM	LFP	115,746	115,746	686,220			686,220
6	Public Service Co of NM	OS					21,120	21,120
7	Salt River Project	NF	1,900	1,900	4,598			4,598
8	Shell Energy North Amer	SFP			-378,450			-378,450
9	Sierra Pacific Power Co	NF	73,208	73,208	383,925			383,925
10	Sierra Pacific Power Co	OS					98,738	98,738
11	Sierra Pacific Power Co	SFP	57,720	57,720	259,163			259,163
12	Surprise Valley Electr.	OLF					9,780	9,780
13	The Energy Authority	SFP			-36,288			-36,288
14	TransAlta Energy Mktg	SFP			-693,675			-693,675
15	Tri-State Gen & Transm	LFP	121,670	127,146	919,899			919,899
16	Tri-State Gen & Transm	NF	275,817	275,817	693,936			693,936
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Tri-State Gen & Transm	OS					191,624	191,624
2	Tucson Electric Power	NF	28	28	87			87
3	Tucson Electric Power	OS					466	466
4	Tucson Electric Power	SFP	1,200	1,200	5,200			5,200
5	Westport Field Srv LLC	LFP			-3,129,096			-3,129,096
6	Western Area Power Adm.	AD	11,604	11,604	50,375		-20,013	30,362
7	Western Area Power Adm.	FNS			5,064,438			5,064,438
8	Western Area Power Adm.	LFP	377,707	377,707	2,180,000			2,180,000
9	Western Area Power Adm.	NF	540,274	540,274	1,223,659			1,223,659
10	Western Area Power Adm.	OS					556,622	556,622
11	Western Area Power Adm.	OS						
12	Western Area Power Adm.	SFP	165,241	165,241	259,689			259,689
13	Accrual						-448,372	-448,372
14								
15								
16								
	TOTAL		15,490,637	15,878,375	113,594,586	5,089,725	19,550,543	138,234,854

Schedule Page: 332 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "ARIZONA PUBLIC SERVICE" ON PAGE 332: Complete name is Arizona Public Service Company.

Schedule Page: 332 Line No.: 1 Column: b

Settlement Adjustment.

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

Arizona Public Service Company - Contract Termination Dates: May 1, 2013, August 31, 2013, January 11, 2041 and May 31, 2047.

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

Credit for unreserved use.

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

Ancillary Services.

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

Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Agreement between PacifiCorp and Arizona Public Service Company ("Restated TSA"), Rate Schedule 436). The contract terminates October 31, 2020. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form No. 1.

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

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BASIN ELECT. POWER COOP" ON PAGES 332: Complete name is Basin Electric Power Cooperative.

Schedule Page: 332 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BIG HORN RURAL ELECTRIC" ON PAGE 332: Complete name is Big Horn Rural Electric Company.

Schedule Page: 332 Line No.: 11 Column: b

Big Horn Rural Electric Company - Contract Termination Date: March 10, 2012.

Schedule Page: 332 Line No.: 11 Column: g

Use of Facilities.

Schedule Page: 332 Line No.: 12 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.: 12 Column: b

Settlement Adjustment.

Schedule Page: 332 Line No.: 12 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332 Line No.: 14 Column: b

Bonneville Power Administration - Contract Termination Dates: December 1, 2011, April 1, 2012, July 1, 2012, November 1, 2012, September 1, 2013, October 1, 2013, December 1, 2013, January 1, 2014, November 1, 2014, November 1, 2015, July 1, 2016, December 1, 2016, October 1, 2027, November 1, 2033 and evergreen.

Schedule Page: 332 Line No.: 16 Column: b

Bonneville Power Administration - Contract Termination Dates: October 3, 2014, December 31, 2018, September 30, 2027 and evergreen.

Schedule Page: 332 Line No.: 16 Column: g

Use of Facilities.

Schedule Page: 332.1 Line No.: 1 Column: g

Ancillary Services. Use of Facilities.

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

Legacy Contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form No.1.

Schedule Page: 332.1 Line No.: 4 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CA IND. SYS. OPERATOR" ON PAGE 332: Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 4 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 4 Column: g
Ancillary Services.

Schedule Page: 332.1 Line No.: 5 Column: g
Ancillary Services.

Schedule Page: 332.1 Line No.: 7 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET GEN & TRANS" ON PAGE 332: Complete name is Deseret Generation and Transmission Cooperative.

Schedule Page: 332.1 Line No.: 7 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 8 Column: b
Deseret Generation and Transmission Cooperative - Contract Termination Dates: October 31, 2012 and September 1, 2018.

Schedule Page: 332.1 Line No.: 10 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "EL PASO ELECT. CO." ON PAGE 332: Complete name is El Paso Electric Company.

Schedule Page: 332.1 Line No.: 10 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 11 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "FLATHEAD ELECT. COOP." ON PAGE 332: Complete name is Flathead Electric Cooperative, Inc.

Schedule Page: 332.1 Line No.: 11 Column: g
Use of Facilities.

Schedule Page: 332.1 Line No.: 12 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "HERMISTON GENERATING CO" ON PAGE 332: Complete name is Hermiston Generating Company, L.P.

Schedule Page: 332.1 Line No.: 12 Column: g
Use of Facilities.

Schedule Page: 332.1 Line No.: 13 Column: b
Settlement Adjustment.

Schedule Page: 332.1 Line No.: 13 Column: e
Credit for unreserved use.

Schedule Page: 332.1 Line No.: 13 Column: g
Respondent's portion of specified costs of certain facilities.

Schedule Page: 332.1 Line No.: 15 Column: b
Idaho Power Company - Contract Termination Date: April 1, 2025 and July 1, 2025.

Schedule Page: 332.2 Line No.: 1 Column: e
Credit for unreserved use.

Schedule Page: 332.2 Line No.: 1 Column: g
Ancillary Services. Use of Facilities. Respondent's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 2 Column: b
Legacy Contract (Rate Schedule 427) executed between PacifiCorp and Idaho Power Company concerning the exchange of transmission services over agreed-upon facilities (Draft Transmission Services Agreement between PacifiCorp and Idaho Power Company, Draft 1 – 5/19/95 ("Goshen Agreement")). Termination of this agreement occurs at the end of the calendar month following the earlier of the effectiveness of a replacement contract, or upon three years written notice of termination as long as PacifiCorp has facilities in place to serve PacifiCorp's Big Grassy load. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form No. 1.

Schedule Page: 332.2 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “MOON LAKE ELECT. ASSOC.” ON PAGE 332: 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.: 7 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “MORGAN STANLEY CAPITAL” ON PAGE 332: Complete name is Morgan Stanley Capital Group, Inc.

Schedule Page: 332.2 Line No.: 7 Column: e

Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.2 Line No.: 9 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “NORTHWESTERN CORP.” ON PAGE 332: Complete name is NorthWestern Corporation.

Schedule Page: 332.2 Line No.: 12 Column: g

Ancillary Services.

Schedule Page: 332.2 Line No.: 14 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PLATTE RIVER POWER” ON PAGE 332: Complete name is Platte River Power Authority.

Schedule Page: 332.2 Line No.: 14 Column: b

Platte River Power Authority - Contract Termination Date: October 31, 2012.

Schedule Page: 332.2 Line No.: 16 Column: g

Ancillary Services.

Schedule Page: 332.3 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PORTLAND GEN. ELECTRIC” ON PAGE 332: Complete name is Portland General Electric Company.

Schedule Page: 332.3 Line No.: 1 Column: b

Settlement Adjustment.

Schedule Page: 332.3 Line No.: 1 Column: g

Ancillary Services.

Schedule Page: 332.3 Line No.: 2 Column: b

Portland General Electric Company - Contract Termination Date: Upon two years written notice.

Schedule Page: 332.3 Line No.: 2 Column: g

Use of Facilities.

Schedule Page: 332.3 Line No.: 3 Column: e

Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.3 Line No.: 4 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUBLIC SERVICE CO OF CO” ON PAGE 332: Complete name is Public Service Company of Colorado.

Schedule Page: 332.3 Line No.: 4 Column: b

Public Service Company of Colorado - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.3 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “PUBLIC SERVICE CO OF NM” ON PAGE 332: Complete name is Public Service Company of New Mexico.

Schedule Page: 332.3 Line No.: 5 Column: b

Public Service Company of New Mexico - Contract Termination Date: December 1, 2012.

Schedule Page: 332.3 Line No.: 6 Column: g
Ancillary Services.

Schedule Page: 332.3 Line No.: 8 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “SHELL ENERGY NORTH AMER" ON PAGE 332: Complete name is Shell Energy North America (US), L.P.

Schedule Page: 332.3 Line No.: 8 Column: e
Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.3 Line No.: 9 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “SIERRA PACIFIC POWER CO” ON PAGE 332: Complete name is Sierra Pacific Power Company.

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: Complete name is Surprise Valley Electrification Corp.

Schedule Page: 332.3 Line No.: 12 Column: b
Surprise Valley Electrification Corp. - Contract Termination Date: Evergreen.

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 “THE ENERGY AUTHORITY” ON PAGE 332: Complete name is The Energy Authority, 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 “TRANSALTA ENERGY MKTG” ON PAGE 332: Complete name is TransAlta Energy Marketing (U.S.) Inc.

Schedule Page: 332.3 Line No.: 14 Column: e
Reassignment of Bonneville Power Administration Transmission.

Schedule Page: 332.3 Line No.: 15 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “TRI-STATE GEN & TRANSM” ON PAGE 332: Complete name is Tri-State Generation and Transmission Association, Inc.

Schedule Page: 332.3 Line No.: 15 Column: b
Tri-State Generation and Transmission Association, Inc. - Contract Termination Date: The date that all generating plants comprising PacifiCorp resources associated with this agreement have been retired from service or interests transferred.

Schedule Page: 332.4 Line No.: 1 Column: g
Ancillary Services.

Schedule Page: 332.4 Line No.: 2 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “TUCSON ELECTRIC POWER” ON PAGE 332: Complete name is Tucson Electric Power Company.

Schedule Page: 332.4 Line No.: 3 Column: g
Ancillary Services.

Schedule Page: 332.4 Line No.: 5 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “WESTPORT FIELD SRV LLC” ON PAGE 332: Complete name is Westport Field Services, LLC.

Schedule Page: 332.4 Line No.: 5 Column: b
Westport Field Services, LLC - Contract Termination Date: Evergreen.

Schedule Page: 332.4 Line No.: 5 Column: e
Reimbursement for providing third party service.

Schedule Page: 332.4 Line No.: 6 Column: a
THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “WESTERN AREA POWER ADM.” ON PAGE 332: Complete name is Western Area Power Administration.

Schedule Page: 332.4 Line No.: 6 Column: b
Settlement Adjustment.

Schedule Page: 332.4 Line No.: 6 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.4 Line No.: 8 Column: b

Western Area Power Administration - Contract Termination Date: May 31, 2022.

Schedule Page: 332.4 Line No.: 10 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.4 Line No.: 11 Column: b

Legacy Contract (Rate Schedule 664) executed between PacifiCorp and Western Area Power Administration concerning the exchange of transmission services over agreed-upon facilities. The contract terminates 50 years from execution. See also FERC Account 456.1, Transmission of electricity for others, page 328 of this Form No. 1.

Schedule Page: 332.4 Line No.: 13 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 FERC Account 565, Transmission of electricity by others, during the period.

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,003,108
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 & Economic Development and	
8	Corporate Memberships & Subscriptions:	
9	Bend 2030	10,000
10	Carbon County Economic Development Corporation	5,000
11	Clatsop Economic Development	5,000
12	Economic Development Corporation of Utah	11,600
13	Linn-Benton Community College	5,000
14	Utah Governor's Economic Summit	10,000
15	Oregon Economic Development Association	10,000
16	Port of Columbia	5,000
17	Siskiyou County Economic Development	10,000
18	Southeast Utah Community Development Corporation	6,750
19	Southern Oregon Regional Economic Development Inc	6,500
20	State of Oregon	10,000
21	State of Utah	10,000
22	Uintah County Economic Development	5,000
23	Wyoming Economic Development Association	10,000
24	Associated Oregon Industries	28,000
25	Economic Development For Central Oregon	7,500
26	Four County Economic Development Corp	25,000
27	Intermountain Electrical Association	9,000
28	Northern Tier Transmission Group	209,044
29	Oregon Business Association	12,250
30	Oregon Business Council	30,206
31	Oregon Sports Authority Foundation	5,000
32	Oregon State University	15,000
33	Pacific Northwest Utilities Conference	69,069
34	Portland Business Alliance	39,400
35	Redmond Economic Development	5,000
36	Rocky Mountain Electrical League	18,000
37	Salt Lake Area Chamber Of Commerce	30,555
38	South Coast Development Council Inc	15,000
39	Utah Foundation	26,650
40	Utah Information Technologies	5,500
41	Utah Manufacturers Association	12,000
42	Utah Taxpayers Association	20,000
43	Watson & Renner	50,208
44	Western Electricity Coordinating Council	3,113,443
45	Western Energy Institute	42,977
46	TOTAL	15,710,771

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Wyoming Business Alliance	5,000
7	Wyoming Taxpayers Association	8,000
8	Yakima County Development	7,500
9	Other	195,877
10		
11	Director's Fees - Regional Advisory Boards	22,444
12		
13	General:	
14	MidAmerican Energy Holdings Company Affiliate Svcs.	7,998,043
15	Western Coal Carrier Liability	1,367,188
16	Settlement Fees	92,500
17	Internal Revenue Service	
18	Pollution Control Request Fee	14,000
19	Other	38,172
20		
21	Regulatory Asset Amortization:	
22	Goodnoe Hills Settlement - WY	21,250
23	Lakeside Settlement - WY	27,919
24	Other	1,118
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	15,710,771

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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			38,609,300		38,609,300
2	Steam Production Plant	139,598,874				139,598,874
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	19,021,804		254,126		19,275,930
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	115,518,950				115,518,950
7	Transmission Plant	84,271,946				84,271,946
8	Distribution Plant	150,336,410				150,336,410
9	Regional Transmission and Market Operation					
10	General Plant	36,082,214		3,340,933		39,423,147
11	Common Plant-Electric					
12	TOTAL	544,830,198		42,204,359		587,034,557

B. Basis for Amortization Charges

The Amortization of Limited Term Electric Plant is based on straight-line amortization over the life of the asset.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	HYDRAULIC PROD.						
13	Stairs						
14	336.00 UT	6			6.78		14.70
15							
16	Klamath River						
17	330.20 OR/CA	41			-0.95		8.00
18	330.40 OR/CA	1			-1.12		8.00
19	331.00 OR/CA	13,562			8.58		8.00
20	332.00 OR/CA	33,572			5.89		8.00
21	333.00 OR/CA	17,754			7.41		8.00
22	334.00 OR/CA	15,030			9.61		8.00
23	335.00 OR/CA	172			4.80		8.00
24	336.00 OR/CA	2,548			6.69		8.00
25							
26	WIND GENERATION						
27	Dunlap Ranch I						
28	344.00 WY	5,565	24.87	-1.00	4.06		
29	345.00 WY	12,296	24.87	-1.00	4.06		
30	346.00 WY	149	24.87	-1.00	4.06		
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Schedule Page: 336 Line No.: 12 Column: b

Depreciation expense associated with transportation equipment is generally charged to operations and maintenance expense and construction work in progress. During the year ended December 31, 2011, depreciation expense associated with transportation equipment was $14,396,524.

Schedule Page: 336 Line No.: 12 Column: e

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

Schedule Page: 336 Line No.: 16 Column: a

The depreciation rate changes are for the Klamath hydroelectric system's four mainstem dams (JC Boyle, Iron Gate, Copco No. 1 and Copco No. 2). For further discussion, refer to Note 13 of Notes to Financial Statements in this Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Utah Public Service Commission:				
2	Annual Fee	3,987,973		3,987,973	
3	Rate Case		2,250,421	2,250,421	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	2,614,463		2,614,463	
7	Rate Case		1,261,104	1,261,104	
8	Deferrred Intervenor Funding Grants				37,082
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,316,982		1,316,982	
12	Rate Case		1,557,480	1,557,480	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	536,458		536,458	
17	Rate Case		1,208,962	1,208,962	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	427,197		427,197	
21	Rate Case		1,130,233	1,130,233	
22	Deferred Intervenor Funding Grants (2)		24,095	24,095	43,797
23					
24	California Public Utilities Commission:				
25	Annual Fee	869		869	
26	Rate Case		743,153	743,153	
27	Deferred Intervenor Funding Grants				
28					
29	California Environmental Protection Agency:				
30	Industry Compliance Fee	191,375		191,375	
31					
32	Rate Cases - All States		110,831	110,831	
33					
34	Federal Energy Regulatory Commission:				
35	Annual Fee	1,846,171		1,846,171	
36	Transmission Rate Case		1,336,313	1,336,313	
37	FERC Other Regulatory		1,003,171	1,003,171	
38					
39	Other Regulatory		79,736	79,736	
40					
41	Charges for services from MidAmerican Energy				
42	Holdings Company and its affiliates:				
43	Utah - Rate Case		175	175	
44	Washington - Rate Case		43,196	43,196	
45	FERC - Other Regulatory		186,742	186,742	
46	TOTAL	10,921,488	10,935,612	21,857,100	80,879

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	3,987,973					2
Electric	928	2,250,421					3
							4
							5
Electric	928	2,614,463					6
Electric	928	1,261,104					7
Electric	928		308,561			345,643	8
							9
							10
Electric	928	1,316,982					11
Electric	928	1,557,480					12
							13
							14
							15
Electric	928	536,458					16
Electric	928	1,208,962					17
							18
							19
Electric	928	427,197					20
Electric	928	1,130,233					21
Electric	928	24,095	39,000	928	24,095	58,702	22
							23
							24
Electric	928	869					25
Electric	928	743,153					26
			32,885			32,885	27
							28
							29
Electric	928	191,375					30
							31
Electric	928	110,831					32
							33
							34
Electric	928	1,846,171					35
Electric	928	1,336,313					36
Electric	928	1,003,171					37
							38
Electric	928	79,736					39
							40
							41
							42
Electric	928	175					43
Electric	928	43,196					44
Electric	928	186,742					45
		21,857,100	380,446		24,095	437,230	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	B. Electric R, D & D Performed Externally:	
2	(1) Research Support	Electric Power Research Institute
3		- Membership dues
4		- Seismic Studies of Substation Equipment program
5		- Toxic Release Inventory reporting for power plants program
6		- Utility Gasification Association
7		- Prism 2.0 Regional Energy and Economic Model Development
8	(2) Research Support	Edison Electric Institute
9		- Utility Solid Waste Activities Group - membership dues
10		- Avian Power Line Interaction Committee - membership dues
11	(4) Research Support	National Electric Energy Testing, Research & Applications Center
12		- Membership dues
13		- Participation
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
	275,871	930.2	275,871		3
	20,000	930.2	20,000		4
	12,000	557	12,000		5
	5,000	557	5,000		6
	281,032	930.2	281,032		7
					8
	56,000	930.2	56,000		9
	2,500	930.2	2,500		10
					11
	71,250	930.2	71,250		12
16,352		580	16,352		13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) __ An Original (2) X A Resubmission	06/28/2012	2011/Q4

FOOTNOTE DATA

Schedule Page: 352 Line No.: 13 Column: c

Estimate

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	90,552,812		
4	Transmission	9,559,334		
5	Regional Market			
6	Distribution	42,801,340		
7	Customer Accounts	40,029,642		
8	Customer Service and Informational	5,939,230		
9	Sales			
10	Administrative and General	39,882,825		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	228,765,183		
12	Maintenance			
13	Production	46,830,499		
14	Transmission	13,148,569		
15	Regional Market			
16	Distribution	66,402,294		
17	Administrative and General	2,067,090		
18	TOTAL Maintenance (Total of lines 13 thru 17)	128,448,452		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	137,383,311		
21	Transmission (Enter Total of lines 4 and 14)	22,707,903		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	109,203,634		
24	Customer Accounts (Transcribe from line 7)	40,029,642		
25	Customer Service and Informational (Transcribe from line 8)	5,939,230		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	41,949,915		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	357,213,635		357,213,635
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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	357,213,635		357,213,635
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	151,718,945		151,718,945
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	151,718,945		151,718,945
72	Plant Removal (By Utility Departments)			
73	Electric Plant	10,828,888		10,828,888
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	10,828,888		10,828,888
77	Fuel Stock	2,361,594		2,361,594
78	Miscellaneous Other Income Deductions	522,628		522,628
79	Charges to Affiliates	676,800		676,800
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,561,022		3,561,022
96	TOTAL SALARIES AND WAGES	523,322,490		523,322,490

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	3,904,370	8,321,702	11,068,144	13,075,867
3	Net Sales (Account 447)	(3,091,739)	(5,730,428)	(12,748,467)	(20,339,894)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	812,631	2,591,274	(1,680,323)	(7,264,027)

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: 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	58,667,591	MWh	9,386,815	59,261,270	MWh	10,014,042
4	Energy Imbalance				-145,875	MWh	-2,969,136
5	Operating Reserve - Spinning	63,248,409	MWh	22,934,366	67,800,550	MWh	24,678,648
6	Operating Reserve - Supplement	63,248,409	MWh	22,934,366	67,695,838	MWh	24,639,578
7	Other				494	MWh	8,604
8	Total (Lines 1 thru 7)	185,164,409		55,255,547	194,612,277		56,516,180

Schedule Page: 398   Line No.: 7   Column: g

Emergency Reserve Energy Provided

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	16,569	11	1800	8,682	118	5,249		840	1,680
2	February	17,590	2	800	8,602	118	5,249		1,947	1,674
3	March	15,346	3	800	7,731	100	5,249		838	1,428
4	Total for Quarter 1	49,505			25,015	336	15,747		3,625	4,782
5	April	16,016	8	900	7,518	94	5,249		1,731	1,424
6	May	15,356	17	1000	7,087	82	5,417		1,432	1,338
7	June	18,156	28	1600	8,613	95	5,880		1,822	1,746
8	Total for Quarter 2	49,528			23,218	271	16,546		4,985	4,508
9	July	19,614	6	1700	9,261	101	5,880		2,645	1,727
10	August	19,180	23	1700	9,431	110	5,880		1,881	1,878
11	September	17,306	7	1700	8,510	98	5,267		1,702	1,729
12	Total for Quarter 3	56,100			27,202	309	17,027		6,228	5,334
13	October	15,064	27	800	7,543	93	5,603		429	1,396
14	November	15,125	28	1900	7,827	86	4,962		743	1,507
15	December	15,678	13	1800	8,786	96	4,962		215	1,619
16	Total for Quarter 4	45,867			24,156	275	15,527		1,387	4,522
17	Total Year to Date/Year	201,000			99,591	1,191	64,847		16,225	19,146

Schedule Page: 400 Line No.: 1 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 2 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 3 Column: d
Pacific Standard Time.

Schedule Page: 400 Line No.: 4 Column: e
1st Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: f
1st Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: g
1st Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak. Long-term firm point-to-point reservations have been adjusted so that the monthly megawatt reservations represent an amount at system input as measured by the transmission system loss factor established in FERC Docket No. ER11-3643. This adjustment has been made to ensure that transmission rates are designed fairly and in a non-discriminatory manner and is consistent with the system input measurement utilized for other long-term firm users of PacifiCorp’s transmission system, including network service.

Schedule Page: 400 Line No.: 4 Column: i
1st Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 4 Column: j
1st Quarter 2011 Net System Load information was compiled using metering, scheduling and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 5 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 6 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 7 Column: d
Pacific Daylight Time.

Schedule Page: 400 Line No.: 8 Column: e
2nd Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: f
2nd Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: g
2nd Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak. Long-term firm point-to-point reservations have been adjusted so that the monthly megawatt reservations represent an amount at system input as measured by the transmission system loss factor established in FERC Docket No. ER11-3643. This adjustment has been made to ensure that transmission rates are designed fairly and in a non-discriminatory manner and is consistent with the system input measurement utilized for other long-term firm users of PacifiCorp’s transmission system, including network service.

Schedule Page: 400 Line No.: 8 Column: i
2nd Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 8 Column: j
2nd Quarter 2011 Net System Load information was compiled using metering, scheduling

and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 9 Column: d

Pacific Daylight Time.

Schedule Page: 400 Line No.: 10 Column: d

Pacific Daylight Time.

Schedule Page: 400 Line No.: 11 Column: d

Pacific Daylight Time.

Schedule Page: 400 Line No.: 12 Column: e

3rd Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak.

Schedule Page: 400 Line No.: 12 Column: f

3rd Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 12 Column: g

3rd Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak. Long-term firm point-to-point reservations have been adjusted so that the monthly megawatt reservations represent an amount at system input as measured by the transmission system loss factor established in FERC Docket No. ER11-3643. This adjustment has been made to ensure that transmission rates are designed fairly and in a non-discriminatory manner and is consistent with the system input measurement utilized for other long-term firm users of PacifiCorp’s transmission system, including network service.

Schedule Page: 400 Line No.: 12 Column: i

3rd Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 12 Column: j

3rd Quarter 2011 Net System Load information was compiled using metering, scheduling and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 13 Column: d

Pacific Daylight Time.

Schedule Page: 400 Line No.: 14 Column: d

Pacific Standard Time.

Schedule Page: 400 Line No.: 15 Column: d

Pacific Standard Time.

Schedule Page: 400 Line No.: 16 Column: e

4th Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak net system load for self at time of Transmission System Peak.

Schedule Page: 400 Line No.: 16 Column: f

4th Quarter 2011 Net System Load information was compiled using metering and/or scheduling data. Reflects actual peak of customers' load at time of Transmission System Peak.

Schedule Page: 400 Line No.: 16 Column: g

4th Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak. Long-term firm point-to-point reservations have been adjusted so that the monthly megawatt reservations represent an amount at system input as measured by the transmission system loss factor established in FERC Docket No. ER11-3643. This adjustment has been made to ensure that transmission rates are designed fairly and in a non-discriminatory manner and is consistent with the system input measurement utilized for other long-term firm users of PacifiCorp’s transmission system, including network service.

Schedule Page: 400 Line No.: 16 Column: i

4th Quarter 2011 Net System Load information was compiled using reservations in OASIS at time of Transmission System Peak.

Schedule Page: 400 Line No.: 16 Column: j

4th Quarter 2011 Net System Load information was compiled using metering, scheduling and/or contractual data. Reflects actual peak and/or contractual demands of customers' load at time of Transmission System Peak.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	54,306,866
3	Steam	42,751,096			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	202,448
5	Hydro-Conventional	4,687,360			
6	Hydro-Pumped Storage	-2,356	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	10,564,249
7	Other	7,996,881			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	55,432,981	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	153,800
10	Purchases	14,094,451	27	Total Energy Losses	4,247,434
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	69,474,797
12	Received	14,561,771			
13	Delivered	14,342,455			
14	Net Exchanges (Line 12 minus line 13)	219,316			
15	Transmission For Other (Wheeling)				
16	Received	14,698,484			
17	Delivered	14,582,697			
18	Net Transmission for Other (Line 16 minus line 17)	115,787			
19	Transmission By Others Losses	-387,738			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	69,474,797			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	6,145,245	829,592	8,682	11	1800 PST
30	February	5,486,873	787,993	8,602	2	0800 PST
31	March	5,593,923	695,388	7,731	3	0800 PST
32	April	5,452,744	912,780	7,518	8	0900 PDT
33	May	5,372,546	858,111	7,087	17	1000 PDT
34	June	5,478,568	834,335	8,615	28	1500 PDT
35	July	6,175,679	797,371	9,261	6	1700 PDT
36	August	6,273,514	945,911	9,431	23	1700 PDT
37	September	5,651,630	962,343	8,510	7	1700 PDT
38	October	5,754,137	1,112,061	7,543	27	0800 PDT
39	November	5,767,930	932,317	8,018	29	1800 PST
40	December	6,322,008	896,047	8,786	13	1800 PST
41	TOTAL	69,474,797	10,564,249			

Schedule Page: 401 Line No.: 26 Column: b

For metered locations only.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *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			386
7	Plant Hours Connected to Load			8760			8150
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			69			0
12	Net Generation, Exclusive of Plant Use - KWh			1332218000			2688370000
13	Cost of Plant: Land and Land Rights			956546			2468743
14	Structures and Improvements			15338483			59823657
15	Equipment Costs			103948678			462802607
16	Asset Retirement Costs			6676303			39000
17	Total Cost			126920010			525134007
18	Cost per KW of Installed Capacity (line 17/5) Including			672.9587			1268.4396
19	Production Expenses: Oper, Supv, & Engr			44274			2321461
20	Fuel			20346469			54754988
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1629639			8463931
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			2111880			1143719
26	Misc Steam (or Nuclear) Power Expenses			4213408			1678311
27	Rents			0			623
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			2009197
30	Maintenance of Structures			325434			645306
31	Maintenance of Boiler (or reactor) Plant			2483678			4986755
32	Maintenance of Electric Plant			623477			692107
33	Maintenance of Misc Steam (or Nuclear) Plant			274457			2069412
34	Total Production Expenses			32052716			78765810
35	Expenses per Net KWh			0.0241			0.0293
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	622119	946	0	1525966	1358	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11896	138000	0	9255	130677	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	31.638	127.607	0.000	34.339	68.717	0.000
41	Average Cost of Fuel per Unit Burned	32.511	127.607	0.000	35.821	68.717	0.000
42	Average Cost of Fuel Burned per Million BTU	1.366	22.016	1.374	1.935	12.521	1.938
43	Average Cost of Fuel Burned per KWh Net Gen	0.015	0.000	0.015	0.020	0.000	0.020
44	Average BTU per KWh Net Generation	11110.245	4.117	11114.362	10506.464	2.772	10509.236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: *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
158	167	739	6
8733	8594	8760	7
0	0	0	8
148	166	762	9
0	0	0	10
0	0	184	11
1024321000	1238973000	5059927000	12
1355853	137086	10449793	13
58963335	36736994	138397193	14
160108957	138115179	727062666	15
39236	35149	11315101	16
220467381	175024408	887224753	17
1416.8855	1016.9925	1086.2203	18
32071	318592	527243	19
14374159	20121375	55295019	20
0	0	0	21
1011088	1470143	157589	22
0	0	0	23
0	0	0	24
61416	539914	0	25
1290085	1164872	17485536	26
19524	0	6135	27
0	0	0	28
242125	697719	0	29
441300	343860	1824395	30
3191174	4569823	10764964	31
391818	2096100	6678185	32
427374	787463	1650053	33
21482134	32109861	94389119	34
0.0210	0.0259	0.0187	35

(d) Coal	(d) Oil	(d) Composite	(e) Coal	(e) Oil	(e) Composite	(f) Coal	(f) Oil	(f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
636245	1678	0	630050	131	0	3590793	22751	0	38
8451	140000	0	9920	133693	0	7947	138000	0	39
19.706	113.969	0.000	31.276	122.081	0.000	14.365	126.447	0.000	40
22.292	113.969	0.000	31.772	122.081	0.000	14.598	126.447	0.000	41
1.319	19.383	1.335	1.601	21.750	1.610	0.919	21.816	0.967	42
0.014	0.000	0.014	0.016	0.000	0.016	0.010	0.001	0.011	43
10498.343	9.633	10507.976	10088.714	0.595	10089.309	11278.589	26.061	11304.650	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: *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)			81.40			457.70
6	Net Peak Demand on Plant - MW (60 minutes)			79			434
7	Plant Hours Connected to Load			8657			8026
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			78			418
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			0			0
12	Net Generation, Exclusive of Plant Use - KWh			561914000			2845170000
13	Cost of Plant: Land and Land Rights			684554			9688975
14	Structures and Improvements			17564005			63175797
15	Equipment Costs			63820005			270958555
16	Asset Retirement Costs			532363			431476
17	Total Cost			82600927			344254803
18	Cost per KW of Installed Capacity (line 17/5) Including			1014.7534			752.1407
19	Production Expenses: Oper, Supv, & Engr			223582			92
20	Fuel			11038425			45927126
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1043948			3066089
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			306825			0
26	Misc Steam (or Nuclear) Power Expenses			453333			2416651
27	Rents			0			3338
28	Allowances			0			0
29	Maintenance Supervision and Engineering			342384			0
30	Maintenance of Structures			284067			2179362
31	Maintenance of Boiler (or reactor) Plant			1247074			5596812
32	Maintenance of Electric Plant			519493			1371394
33	Maintenance of Misc Steam (or Nuclear) Plant			413283			205484
34	Total Production Expenses			15872414			60766348
35	Expenses per Net KWh			0.0282			0.0214
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	272751	592	0	1277765	4134	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11698	136997	0	11590	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	37.320	119.099	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	40.080	119.099	0.000	35.498	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.713	20.697	1.729	1.531	23.754	1.549
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.019	0.016	0.000	0.016
44	Average BTU per KWh Net Generation	11356.161	6.059	11362.220	10410.258	8.421	10418.679

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: *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
280	461	1149	6
6932	7880	8740	7
0	0	0	8
269	460	1147	9
0	0	0	10
0	0	213	11
1613030000	2986883000	7445083000	12
9688975	10275401	29653351	13
51994484	91277571	206447852	14
239661036	410640791	921260382	15
431476	431476	1294428	16
301775971	512625239	1158656013	17
1024.7062	1034.3528	928.5591	18
59	101	252	19
25913796	49631646	121472568	20
0	0	0	21
2014131	3311933	8392153	22
0	0	0	23
0	0	0	24
0	0	0	25
-1773864	2579207	3221994	26
2341	3673	9352	27
0	0	0	28
0	0	0	29
2232392	2136616	6548370	30
8996195	9448392	24041399	31
4119736	1794468	7285598	32
164934	412053	782471	33
41669720	69318089	171754157	34
0.0258	0.0232	0.0231	35

(d) Coal	(d) Oil	(d) Composite	(e) Coal	(e) Oil	(e) Composite	(f) Coal	(f) Oil	(f) Composite	Line No.
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
713870	3562	0	1343957	14267	0	3335592	21963	0	38
11577	138000	0	11413	138000	0	11516	138000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	38.413	136.519	0.000	40
35.619	0.000	0.000	35.484	0.000	0.000	35.518	136.519	0.000	41
1.538	23.562	1.566	1.555	23.494	1.614	1.542	23.554	1.579	42
0.016	0.000	0.016	0.016	0.001	0.017	0.016	0.000	0.016	43
10246.984	12.799	10259.783	10270.174	27.686	10297.860	10318.684	17.098	10335.782	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: *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)			934			1421
7	Plant Hours Connected to Load			8276			8760
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			909			1412
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			163			331
12	Net Generation, Exclusive of Plant Use - KWh			5961371000			8905672000
13	Cost of Plant: Land and Land Rights			2386782			1161925
14	Structures and Improvements			115439586			140256251
15	Equipment Costs			698035416			912532257
16	Asset Retirement Costs			1320578			5049612
17	Total Cost			817182362			1059000045
18	Cost per KW of Installed Capacity (line 17/5) Including			820.4642			685.3926
19	Production Expenses: Oper, Supv, & Engr			13687			15431407
20	Fuel			94465053			205181742
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			7704010			3732333
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			15495
26	Misc Steam (or Nuclear) Power Expenses			12330552			-12200227
27	Rents			1000			227829
28	Allowances			0			0
29	Maintenance Supervision and Engineering			1299908			430025
30	Maintenance of Structures			2441557			8264038
31	Maintenance of Boiler (or reactor) Plant			12135022			25851801
32	Maintenance of Electric Plant			3934986			8293459
33	Maintenance of Misc Steam (or Nuclear) Plant			1146487			3573047
34	Total Production Expenses			135472262			258800949
35	Expenses per Net KWh			0.0227			0.0291
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	2457036	14459	0	4987635	19395	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11682	138000	0	9209	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	35.048	135.969	0.000	42.093	117.187	0.000
41	Average Cost of Fuel per Unit Burned	37.647	135.969	0.000	40.682	117.187	0.000
42	Average Cost of Fuel Burned per Million BTU	1.611	23.459	1.643	2.209	20.219	2.231
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.016	0.023	0.000	0.023
44	Average BTU per KWh Net Generation	9629.811	14.058	9643.869	10315.263	12.622	10327.885

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: *Naughton* (d)			Plant Name: *Wyodak* (e)			Plant Name: *Gadsby Steam* (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			279			196	6
		8760			6079			1228	7
		0			0			0	8
		700			268			231	9
		0			0			0	10
		146			65			34	11
		5102251000			1457709000			69094000	12
		1094739			210526			1252090	13
		70184754			50872324			15095198	14
		545628764			391262775			64530281	15
		14207864			490453			587008	16
		631116121			442836078			81464577	17
		892.4153			1528.6023			323.7861	18
		89488			302145			45847	19
		101169233			15125638			9413917	20
		0			0			0	21
		4470634			13169			0	22
		0			0			0	23
		0			0			0	24
		11279			0			0	25
		13043071			4158309			3660485	26
		1243			5701			0	27
		0			0			0	28
		1343942			0			0	29
		1286755			412626			257733	30
		10693418			8086379			904380	31
		3658603			4195535			1260907	32
		1616276			238999			305328	33
		137383942			32538501			15848597	34
		0.0269			0.0223			0.2294	35
Coal	Gas	Composite	Coal	Oil	Composite	Gas			36
Tons	MCF		Tons	Barrels		MCF			37
2761016	134829	0	1163685	11714	0	1111436	0	0	38
9755	1030	0	7789	138000	0	1029	0	0	39
36.236	8.667	0.000	12.264	131.751	0.000	8.470	0.000	0.000	40
36.219	8.667	0.000	11.672	131.751	0.000	8.470	0.000	0.000	41
1.857	8.418	1.873	0.749	22.731	0.831	8.229	0.000	0.000	42
0.020	0.000	0.020	0.009	0.001	0.010	0.136	0.000	0.000	43
10557.037	27.209	10584.246	12435.966	46.577	12482.543	16556.749	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	16			243		
7	Plant Hours Connected to Load	4553			7179		
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	58348000			1161094000		
13	Cost of Plant: Land and Land Rights	635			842245		
14	Structures and Improvements	337028			12844996		
15	Equipment Costs	1394634			156966194		
16	Asset Retirement Costs	0			214373		
17	Total Cost	1732297			170867808		
18	Cost per KW of Installed Capacity (line 17/5) Including	108.2686			611.1152		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	12500058			59623564		
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	933523			6950632		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	228838			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	976359			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	14638778			66574196		
35	Expenses per Net KWh	0.2509			0.0573		
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	1611369	0	0	8798228	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1039	0	0	1013	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.757	0.000	0.000	6.777	0.000	0.000
41	Average Cost of Fuel per Unit Burned	7.757	0.000	0.000	6.777	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	7.469	0.000	0.000	6.693	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.214	0.000	0.000	0.051	0.000	0.000
44	Average BTU per KWh Net Generation	28684.582	0.000	0.000	7672.944	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: *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
39			26			514			6
8586			6535			2219			7
0			0			0			8
34			14			520			9
0			0			0			10
22			0			18			11
278079000			89501000			664323000			12
41195596			0			1973791			13
8005940			5733734			23249210			14
68821997			28716806			318404262			15
1443379			0			689117			16
119466912			34450540			344316380			17
3135.6145			560.1714			580.3411			18
41563			0			129916			19
0			0			45556011			20
0			0			0			21
49466			0			0			22
3583830			0			0			23
0			0			0			24
0			87940			2781650			25
2207430			0			0			26
6247			0			36263			27
0			0			0			28
0			0			0			29
520949			0			2721			30
172327			0			0			31
268540			0			1753886			32
34658			0			0			33
6885010			87940			50260447			34
0.0248			0.0010			0.0757			35
						Gas			36
						MCF			37
0	0	0	0	0	0	4969662	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	9.167	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	9.167	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	8.884	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.069	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	7718.590	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 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)	132			563		
7	Plant Hours Connected to Load	2591			8560		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	120			550		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			19		
12	Net Generation, Exclusive of Plant Use - KWh	125295000			2397142000		
13	Cost of Plant: Land and Land Rights	0			3403277		
14	Structures and Improvements	4240304			43915462		
15	Equipment Costs	74912221			307655824		
16	Asset Retirement Costs	0			134848		
17	Total Cost	79152525			355109411		
18	Cost per KW of Installed Capacity (line 17/5) Including	437.0653			626.4057		
19	Production Expenses: Oper, Supv, & Engr	0			96501		
20	Fuel	11760826			133088264		
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	948474			3039306		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			1363		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	148930			249281		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1192213			1297526		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	14050443			137772241		
35	Expenses per Net KWh	0.1121			0.0575		
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	1477183	0	0	17032691	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1036	0	0	1051	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.962	0.000	0.000	7.814	0.000	0.000
41	Average Cost of Fuel per Unit Burned	7.962	0.000	0.000	7.814	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	7.688	0.000	0.000	7.436	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.094	0.000	0.000	0.056	0.000	0.000
44	Average BTU per KWh Net Generation	12209.186	0.000	0.000	7466.425	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
561	0	0	6
5842	0	0	7
0	0	0	8
558	0	0	9
0	0	0	10
23	0	0	11
1845528000	0	0	12
17296760	0	0	13
27840392	0	0	14
311579774	0	0	15
0	0	0	16
356716926	0	0	17
603.2757	0	0	18
203394	0	0	19
104792180	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
4323244	0	0	25
0	0	0	26
8047	0	0	27
0	0	0	28
0	0	0	29
2538016	0	0	30
0	0	0	31
3719493	0	0	32
0	0	0	33
115584374	0	0	34
0.0626	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas									36
MCF									37
13386308	0	0	0	0	0	0	0	0	38
1022	0	0	0	0	0	0	0	0	39
7.828	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
7.828	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
7.657	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.057	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
7416.014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: c

Cholla

The Cholla Plant is operated by Arizona Public Service Company and is jointly owned. PacifiCorp owns 100% of Unit No. 4 and 36.66% of common facilities. Data reported in column (c) represents PacifiCorp's share.

Schedule Page: 402 Line No.: -1 Column: d

Colstrip

The Colstrip Plant is operated by PPL Montana, LLC and is jointly owned. PacifiCorp owns a 10.0% share of Colstrip Plant Units No. 3 and No. 4. Data reported in column (d) represents PacifiCorp's share.

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. PacifiCorp owns a 19.28% share of Craig Plant Units No. 1 and No. 2 and 12.86% of common facilities. Data in column (e) represents PacifiCorp's share.

Schedule Page: 402 Line No.: 11 Column: c

Cholla - PacifiCorp does not have employees at the Cholla Plant.

Schedule Page: 402 Line No.: 11 Column: d

Colstrip - PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 402 Line No.: 11 Column: e

Craig - PacifiCorp does not have employees at the Craig Plant.

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. PacifiCorp owns a 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. Data reported in column (b) represents PacifiCorp's share.

Schedule Page: 402.1 Line No.: -1 Column: c

Hunter Unit No. 1

The 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 that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2011 were $1.1 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.1 Line No.: -1 Column: d

Hunter Unit No. 2

The 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 that were billed to minority owners for the operation and maintenance (excluding fuel) of this unit for calendar year 2011 were $10.3 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.1 Line No.: -1 Column: f

Hunter - Total Plant

Refer to plant statistics for each Hunter Units Nos. 1, 2 and 3 on page 402.1 and 403.1.

Schedule Page: 402.1 Line No.: 11 Column: b

Hayden - PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 402.1 Line No.: 11 Column: c

Hunter Unit No. 1 - Refer to the Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.1 Line No.: 11 Column: d

Hunter Unit No. 2 - Refer to the Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.1 Line No.: 11 Column: e

Hunter Unit No. 3 - Refer to the Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.2 Line No.: -1 Column: c

Jim Bridger

The Jim Bridger Plant is operated by PacifiCorp and is jointly owned by PacifiCorp and Idaho Power Company with an undivided interest of 66 2/3% and 33 1/3%, respectively. Data reported in column (c) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2011 were $27.6 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: -1 Column: e

Wyodak

The Wyodak Plant is operated by PacifiCorp and is jointly owned by PacifiCorp and Black Hills Corporation with an undivided interest of 80% and 20%, respectively. Data in column (e) represents PacifiCorp's share. Costs that were billed to minority owners for the operation and maintenance (excluding fuel) of this plant for calendar year 2011 were $4.7 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.3 Line No.: -1 Column: b

Little Mountain

The turbine and generator assets at Little Mountain were retired in 2011 as the plant no longer produces electricity. The remaining plant costs represent assets used to produce steam under a steam supply contract that terminates July 31, 2012 or later, based on extension options.

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. PacifiCorp owns a 50.0% share of the Hermiston Plant. Data reported in column (c) represents PacifiCorp's share. See Page 326 - Purchased Power of this Form No. 1 for further information on Hermiston Generating Company, L.P.

Schedule Page: 402.3 Line No.: -1 Column: d

Blundell

All or some of the renewable energy attributes associated with generation from this generating facility may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) 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.

All or some of the renewable energy attributes associated with generation from this generating facility may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 402.3 Line No.: 11 Column: c

Hermiston - PacifiCorp does not have employees at the Hermiston Plant.

Schedule Page: 402.3 Line No.: 11 Column: e

Camas Co-Gen - PacifiCorp does not have employees at the Camas Paper Mill.

Schedule Page: 402.4 Line No.: 11 Column: b

Gadsby Peakers - Refer to the Gadsby Steam Plant on page 403.2 for the average number of employees.

Schedule Page: 402 Line No.: 36 Column: b2

Carbon - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: c2

Cholla - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: d2

Colstrip - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: e2

Craig - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 36 Column: f2

Dave Johnston - Fuel oil is used for start-up purposes.

Schedule Page: 402 Line No.: 40 Column: e1

Craig - Amended in accordance with FERC Order No. AC11-132.

Schedule Page: 402.1 Line No.: 36 Column: b2

Hayden - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: c2

Hunter Unit No. 1 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: d2

Hunter Unit No. 2 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: e2

Hunter Unit No. 3 - Fuel oil is used for start-up purposes.

Schedule Page: 402.1 Line No.: 36 Column: f2

Hunter - Total Plant - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: b2

Huntington - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: c2

Jim Bridger - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: d2

Naughton - Natural gas is used for start-up purposes.

Schedule Page: 402.2 Line No.: 36 Column: e2

Wyodak - Fuel oil is used for start-up purposes.

Schedule Page: 402.2 Line No.: 40 Column: c1

Jim Bridger - Amended in accordance with FERC Order No. AC11-132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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. 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)	26	33
7	Plant Hours Connect to Load	8,645	8,345
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	3
12	Net Generation, Exclusive of Plant Use - Kwh	113,105,000	142,876,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,617,856	2,240,353
16	Reservoirs, Dams, and Waterways	2,855,309	2,954,724
17	Equipment Costs	5,169,115	10,336,290
18	Roads, Railroads, and Bridges	105,442	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	9,854,741	16,031,869
21	Cost per KW of Installed Capacity (line 20 / 5)	492.7371	593.7729
22	Production Expenses		
23	Operation Supervision and Engineering	-39,865	-36,851
24	Water for Power	0	0
25	Hydraulic Expenses	2,945	3,976
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,345,967	1,772,458
28	Rents	3,153	1,623
29	Maintenance Supervision and Engineering	92	125
30	Maintenance of Structures	12,826	22,382
31	Maintenance of Reservoirs, Dams, and Waterways	47,102	112,306
32	Maintenance of Electric Plant	231,505	238,814
33	Maintenance of Misc Hydraulic Plant	20,931	38,543
34	Total Production Expenses (total 23 thru 33)	1,624,656	2,153,376
35	Expenses per net KWh	0.0144	0.0151

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
12	20	29	6
8,311	8,733	8,270	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
43,500,000	56,329,000	158,075,000	12
			13
0	0	3,505,129	14
1,222,452	1,632,875	3,968,892	15
4,526,756	14,763,237	7,529,121	16
1,188,143	1,635,739	14,555,560	17
50,817	250,151	572,059	18
0	0	0	19
6,988,168	18,282,002	30,130,761	20
465.8779	703.1539	1,004.3587	21
			22
-25,475	-45,372	-65,863	23
9,684	16,786	0	24
56,677	98,240	54,686	25
0	0	0	26
392,897	523,610	837,252	27
-11,754	-20,374	-159	28
69	120	0	29
57,831	36,724	15,336	30
18,966	33,312	41,325	31
98,561	22,266	33,113	32
45,038	74,187	233,527	33
642,494	739,499	1,149,217	34
0.0148	0.0131	0.0073	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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: 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	29
7	Plant Hours Connect to Load	5,730	8,484
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	46,160,000	163,373,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	914,418	1,767,508
16	Reservoirs, Dams, and Waterways	12,176,001	10,885,301
17	Equipment Costs	1,790,164	4,274,112
18	Roads, Railroads, and Bridges	533,015	94,793
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,413,598	17,083,883
21	Cost per KW of Installed Capacity (line 20 / 5)	1,401.2362	517.6934
22	Production Expenses		
23	Operation Supervision and Engineering	-18,149	-409,794
24	Water for Power	7,102	0
25	Hydraulic Expenses	41,563	60,715
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	351,274	1,896,430
28	Rents	-8,620	3,991
29	Maintenance Supervision and Engineering	51	0
30	Maintenance of Structures	17,360	39,377
31	Maintenance of Reservoirs, Dams, and Waterways	44,034	319,732
32	Maintenance of Electric Plant	19,596	64,174
33	Maintenance of Misc Hydraulic Plant	43,558	101,709
34	Total Production Expenses (total 23 thru 33)	497,769	2,076,334
35	Expenses per net KWh	0.0108	0.0127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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
19	83	32	6
8,385	6,678	8,589	7
			8
19	83	32	9
19	83	32	10
1	2	1	11
119,843,000	335,014,000	168,158,000	12
			13
341,706	26,277	0	14
6,586,042	3,118,097	2,117,062	15
13,274,563	14,487,097	15,174,982	16
2,460,471	14,989,026	6,059,746	17
1,076,116	886,710	484,728	18
0	0	0	19
23,738,898	33,507,207	23,836,518	20
1,318.8277	341.9801	745.1240	21
			22
1,091,878	293,295	-48,405	23
0	0	20,653	24
33,634	14,430	120,873	25
0	0	0	26
1,209,642	713,604	659,403	27
1,226	-901	-25,068	28
83	452	148	29
4,224	13,244	48,126	30
15,198	66,266	115,630	31
252,088	162,703	24,353	32
15,058	65,017	91,279	33
2,623,031	1,328,110	1,006,992	34
0.0219	0.0040	0.0060	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	38.50	136.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	139
7	Plant Hours Connect to Load	8,092	8,759
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	151
10	(b) Under the Most Adverse Oper Conditions	39	151
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	182,966,000	576,030,000
13	Cost of Plant		
14	Land and Land Rights	0	1,962,905
15	Structures and Improvements	3,773,652	44,188,188
16	Reservoirs, Dams, and Waterways	31,682,299	11,656,735
17	Equipment Costs	11,736,506	17,986,931
18	Roads, Railroads, and Bridges	1,879,202	2,148,089
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,071,659	77,942,848
21	Cost per KW of Installed Capacity (line 20 / 5)	1,274.5885	573.1092
22	Production Expenses		
23	Operation Supervision and Engineering	-55,033	778,698
24	Water for Power	24,856	19,597
25	Hydraulic Expenses	145,471	648,649
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	751,145	1,131,169
28	Rents	-30,169	-77,088
29	Maintenance Supervision and Engineering	178	0
30	Maintenance of Structures	69,888	149,101
31	Maintenance of Reservoirs, Dams, and Waterways	145,813	104,392
32	Maintenance of Electric Plant	96,033	137,493
33	Maintenance of Misc Hydraulic Plant	117,042	312,967
34	Total Production Expenses (total 23 thru 33)	1,265,224	3,204,978
35	Expenses per net KWh	0.0069	0.0056

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	23	36	6
8,755	8,760	8,373	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
263,816,000	77,321,000	251,221,000	12
			13
0	36,698	105,168	14
2,228,536	1,934,364	2,949,451	15
10,730,142	6,065,660	24,998,656	16
3,285,502	5,185,586	3,834,999	17
264,441	503,332	287,997	18
0	0	0	19
16,508,621	13,725,640	32,176,271	20
388.4381	457.5213	1,005.5085	21
			22
-73,100	-378,124	270,681	23
27,438	0	36,925	24
160,585	55,196	11,433	25
0	0	0	26
726,392	1,006,504	550,234	27
-33,304	2,537	3,507	28
196	0	148	29
61,154	9,030	53,010	30
131,754	5,549	157,137	31
88,478	84,952	43,393	32
121,268	115,315	86,578	33
1,210,861	900,959	1,213,046	34
0.0046	0.0117	0.0048	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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)	17	8
7	Plant Hours Connect to Load	3,059	8,350
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	37,135,000	35,155,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	1,805,693	675,249
16	Reservoirs, Dams, and Waterways	13,887,672	8,266,187
17	Equipment Costs	9,307,477	5,305,392
18	Roads, Railroads, and Bridges	474,194	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	25,475,036	14,757,911
21	Cost per KW of Installed Capacity (line 20 / 5)	1,415.2798	1,054.1365
22	Production Expenses		
23	Operation Supervision and Engineering	-31,242	-157,778
24	Water for Power	14,121	0
25	Hydraulic Expenses	68,012	25,758
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	364,257	601,475
28	Rents	-14,105	1,184
29	Maintenance Supervision and Engineering	83	0
30	Maintenance of Structures	26,116	462
31	Maintenance of Reservoirs, Dams, and Waterways	177,004	1,911
32	Maintenance of Electric Plant	33,131	37,022
33	Maintenance of Misc Hydraulic Plant	160,135	42,990
34	Total Production Expenses (total 23 thru 33)	797,512	553,024
35	Expenses per net KWh	0.0215	0.0157

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	257	163	6
8,749	6,410	6,627	7
			8
12	264	164	9
12	263	164	10
1	2	2	11
70,977,000	791,748,000	661,211,000	12
			13
0	7,813,808	8,349,393	14
1,165,632	31,891,473	7,680,925	15
13,609,716	42,715,637	27,653,817	16
2,177,660	16,789,892	14,832,272	17
56,124	1,012,079	1,439,462	18
0	0	0	19
17,009,132	100,222,889	59,955,869	20
1,546.2847	417.5954	447.4319	21
			22
-7,982	1,346,620	763,873	23
7,102	34,584	19,309	24
41,563	1,278,034	639,110	25
0	0	0	26
289,766	1,602,699	991,015	27
-8,620	-136,038	-75,955	28
51	0	0	29
16,149	35,542	40,796	30
17,328	63,120	79,510	31
12,258	170,448	212,959	32
31,387	490,818	348,809	33
399,002	4,885,827	3,019,426	34
0.0056	0.0062	0.0046	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	8,740	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	3	0
12	Net Generation, Exclusive of Plant Use - Kwh	45,255,000	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	368,652	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)	942,424	0
21	Cost per KW of Installed Capacity (line 20 / 5)	91.4975	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	-23,072	0
24	Water for Power	0	0
25	Hydraulic Expenses	18,775	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	327,521	0
28	Rents	-54	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	2,065	0
31	Maintenance of Reservoirs, Dams, and Waterways	1,229	0
32	Maintenance of Electric Plant	13,335	0
33	Maintenance of Misc Hydraulic Plant	145,068	0
34	Total Production Expenses (total 23 thru 33)	484,867	0
35	Expenses per net KWh	0.0107	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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

This footnote applies to all hydroelectric generating facilities with current generation. 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 RPS 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 Line No.: 28 Column: d

This footnote applies to all instances of credit amounts in Rents. The credit amounts represent differences between accrued and actual rents.

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

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: 406.4 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 takes all of the generation. The cost of the Olmsted plant includes leasehold improvements and facilities to which PacifiCorp holds title.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	6.70	6.6	18,071,000	18,738,643
3	Bend		1913	1.11	1.0	2,115,000	1,335,093
4	Big Fork	2652	1910	4.15	4.6	34,671,000	7,337,583
5	Cline Falls		1913	1.00			
6	Condit	2342	1913	13.70	15.0	88,226,000	1,515,294
7	Eagle Point		1957	2.81	2.8	18,508,000	1,817,948
8	East Side	2082	1924	3.20			1,991,695
9	Fall Creek	2082	1903	2.20	2.0	11,651,000	1,368,783
10	Fountain Green		1922	0.16	0.1	69,000	597,630
11	Granite		1896	2.00	1.2	8,377,000	5,234,157
12	Gunlock		1917	0.75	0.4	2,198,000	683,159
13	Last Chance		1983	1.73	1.4	6,943,000	2,802,615
14	Paris		1910	0.72	0.7	3,126,000	438,870
15	Pioneer	2722	1897	5.00	4.0	28,634,000	10,923,580
16	Powerdale	2659	1923	6.00			66,518
17	Prospect No. 1	2630	1912	3.76	4.6	24,770,000	1,795,629
18	Prospect No. 3	2337	1932	7.20	7.7	46,679,000	7,012,132
19	Prospect No. 4	2630	1944	1.00	0.9	4,925,000	1,735,569
20	Sand Cove		1926	0.80	0.5	2,304,000	933,722
21	Snake Creek		1910	1.18	1.0	3,539,000	
22	Stairs	597	1895	1.00	1.2	7,356,000	1,621,161
23	St. Anthony	2381	1915	0.50			1,337,279
24	Veyo		1920	0.50	0.3	1,359,000	875,122
25	Viva Naughton		1986	0.74	0.6	773,000	1,194,486
26	Wallowa Falls	308	1921	1.10	1.0	7,892,000	2,833,542
27	Weber	1744	1911	3.85	2.0	23,866,000	2,957,569
28	West Side	2082	1908	0.60	0.6	2,040,000	468,574
29	Keno Regulating Dam	2082					7,529,514
30	Upper Klamath Lake	2082					3,847,587
31	North Umpqua	1927					15,790,442
32							
33	Pumping Plant:						
34	Lifton		1917	-4.50	-2.0	-2,356,000	19,246,861
35							
36	Wind:						
37	Dunlap Ranch 1		2010	111.00	112.0	421,086,000	239,610,220
38	Foote Creek		1999	32.62	32.0	105,082,000	36,513,348
39	Glenrock		2008	99.00	103.0	340,863,000	200,963,100
40	Glenrock III		2009	39.00	38.0	130,197,000	87,208,182
41	Rolling Hills		2009	99.00	103.0	309,180,000	201,322,304
42	Goodnoe Hills		2008	94.00	95.0	239,431,000	181,825,142
43	Leaning Juniper 1		2006	100.50	102.0	234,789,000	174,811,148
44	Marengo		2007	140.40	139.0	403,408,000	237,829,066
45	Marengo II		2008	70.20	69.0	194,378,000	128,272,296
46	Seven Mile Hill		2008	99.00	100.0	381,679,000	199,452,559

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
2,796,812	430,337		88,851	Water		2
1,202,786	65,032		92,127	Water		3
1,768,092	345,945		151,153	Water		4
	2,842		494	Water		5
110,605	209,397		40,064	Water		6
646,957	233,734		97,402	Water		7
622,405	-28,259		9,989	Water		8
622,174	175,143		104,368	Water		9
3,735,188	21,797		5,808	Water		10
2,617,079	143,210		25,155	Water		11
910,879	63,876		41,721	Water		12
1,620,009	105,552		29,285	Water		13
609,542	62,906		33,944	Water		14
2,184,716	297,559		125,685	Water		15
11,086	28,411		5,624	Water		16
477,561	205,274		36,778	Water		17
973,907	309,200		339,943	Water		18
1,735,569	121,086		31,308	Water		19
1,167,153	64,358		53,637	Water		20
	81,443		17,063	Water		21
1,621,161	175,080		80,317	Water		22
2,674,558	58,950		2,578	Water		23
1,750,244	72,728		136,045	Water		24
1,614,170	120,554		27,458	Water		25
2,575,947	54,602		32,888	Water		26
768,200	275,584		60,819	Water		27
780,957	46,788		13,871	Water		28
	8,088		1,673			29
	340,976		26,082			30
						31
						32
						33
-4,277,080	346,764		56,364	Water		34
						35
						36
2,158,651	2,206,801		108,206	Wind		37
1,119,355	1,916,623		106,885	Wind		38
2,029,930	1,009,112		458,098	Wind		39
2,236,107	358,639		168,292	Wind		40
2,033,559	1,084,314		427,203	Wind		41
1,934,310	1,329,935		1,497,159	Wind		42
1,739,414	2,151,942		418,786	Wind		43
1,693,939	5,574,816		172,606	Wind		44
1,827,241	2,741,761		19,894	Wind		45
2,014,672	1,622,325		512,371	Wind		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Seven Mile Hill II	2008	19.50	20.0	83,613,000	41,854,410
2	High Plains	2009	99.00	98.0	335,463,000	219,125,791
3	McFadden Ridge I	2009	28.50	29.0	102,595,000	56,802,683
4						
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						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
2,146,380	304,785		103,509	Wind		1
2,213,392	995,588		2,138,787	Wind		2
1,993,077	276,012		631,060	Wind		3
						4
						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
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

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.

This footnote applies to all hydroelectric generating facilities with current generation. 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 RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 5 Column: a

Cline Falls

The Cline Falls hydroelectric generating facility was retired in August 2010.

Schedule Page: 410 Line No.: 6 Column: a

Condit

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric generating facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. In early February 2005, the parties agreed to modify the settlement agreement, establishing a total cost to decommission not to exceed $21 million, excluding inflation. In October 2010, the Washington Department of Ecology issued a Clean Water Act 401 certificate, and in December 2010, the FERC issued a surrender order for project decommissioning modifying PacifiCorp's proposed decommissioning plans and directing a 2011 decommissioning. In January 2011, PacifiCorp filed a request for clarification and rehearing of the surrender order and a motion for stay with the FERC requesting reinstatement of PacifiCorp's decommissioning proposal. In April 2011, the FERC issued an order on rehearing, granting PacifiCorp nearly all of the changes it requested, but did not shorten the required agency consultation and FERC approval periods. In June 2011, PacifiCorp formally notified the FERC of its acceptance of the terms and conditions of the orders that govern the surrender of the project license. PacifiCorp commenced on-site decommissioning activities in June 2011 and the dam was breached in late October 2011 as planned. Post breach, near-term activities will focus on sediment monitoring as material moves downstream into the Columbia River. Removal of project facilities commenced in January 2012, and complete dam removal is expected by August 2012.

Schedule Page: 410 Line No.: 16 Column: a

Powerdale

The Powerdale hydroelectric generating facility was decommissioned in October 2010.

Schedule Page: 410 Line No.: 21 Column: a

Snake Creek

The Snake Creek hydroelectric generating facility was sold to Heber Light & Power Company in September 2011 and was recorded in Account 102, Electric plant purchased or sold.

Schedule Page: 410 Line No.: 23 Column: a

St. Anthony

Licensed Project No. 2381 applicable to both Ashton and St. Anthony plants.

Schedule Page: 410 Line No.: 29 Column: a

Keno 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, JC Boyle and Iron Gate).

Schedule Page: 410 Line No.: 31 Column: a

North Umpqua

Represents facilities that support the North Umpqua River system projects. All common roads, employee houses, control equipment, etc. are in this account.

Schedule Page: 410 Line No.: 36 Column: a

This footnote applies to all wind-powered generating facilities with current generation. 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 RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 38 Column: a

Foote Creek

The Foote Creek wind-powered generating facility is operated by SeaWest Energy and owned by PacifiCorp and Eugene Water and Electric Board with an undivided interest of 78.79% and 21.21%, respectively. Data reported in row 38 represents PacifiCorp's share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (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 , ID	MALIN , OR	500.00	500.00	Steel Tower	447.00		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 500kV					1,212.00		12
16								
17	BEN LOMOND, UT	BORAH, ID	345.00	345.00	Wood - H	138.00		1
18	BEN LOMOND, UT	TERMINAL, UT	345.00	345.00			47.00	1
19	BEN LOMOND, UT	CAMP WILLIAMS, UT	345.00	345.00	Steel SP	69.00		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 #1, UT	345.00	345.00			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 #2, UT	345.00	345.00	Steel SP	26.00		1
27	TERMINAL, UT	CAMP WILLIAMS, 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	Steel Tower	41.00		1
33	HUNTINGTON, UT	PINTO, UT	345.00	345.00	Wood - H	159.00		1
34	HUNTINGTON, UT	SPANISH FORK, UT	345.00	345.00	Steel Tower	78.00		1
35	TERMINAL, UT	NINETY SOUTH, UT	345.00	345.00			16.00	1
36					TOTAL	15,957.00	806.00	264

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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
	14,275,676	269,729,474	284,005,150		1,409,233	275,506	1,684,739	13
								14
	14,275,676	269,729,474	284,005,150		1,409,233	275,506	1,684,739	15
								16
2-954 ACSR 45/7								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 45/7								24
2-1272 ACSR 45/7								25
2-1272 ACSR 45/7								26
2-1272 ACSR 45/7								27
2-954 ACSR 45/7								28
2-954 ACSR 45/7								29
2-954 ACSR 54/7								30
2-795 ACSR 45/7								31
2-795 ACSR 26/7								32
2-795 ACSR 45/7								33
2-1272 ACSR 45/7								34
2-1272 ACSR 45/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	MONA, UT	SIGURD #1, UT	345.00	345.00	Wood - H	69.00		1
2	MONA, UT	SIGURD #2, UT	345.00	345.00	Steel Tower		69.00	1
3	SIGURD, UT	UT / NV BORDER, UT	345.00	345.00	Steel Tower	190.00		1
4	JIM BRIDGER, WY	BORAH, ID	345.00	345.00	Steel Tower	240.00		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	Wood - H	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	Steel SP	5.00	42.00	1
9	POPULUS #1, ID	BEN LOMOND, UT	345.00	345.00			82.00	1
10	POPULUS #2, ID	BEN LOMOND, UT	345.00	345.00	Steel SP	86.00		1
11	BEN LOMOND, UT	TERMINAL #1, UT	345.00	345.00			47.00	1
12	BEN LOMOND, UT	TERMINAL #2, UT	345.00	345.00	Steel SP	47.00		1
13	90TH SOUTH, UT	CAMP WILLIAMS #4, UT	345.00	345.00			11.00	1
14	90TH SOUTH, UT	CAMP WILLIAMS #3, UT	345.00	345.00	Steel SP	11.00		1
15	345 kV costs and expenses							
16								
17	Subtotal 345kV					1,986.00	383.00	33
18								
19	ANTELOPE, ID	ANACONDA, ID - MT	230.00	230.00	Wood - H	76.00		1
20	ANTELOPE, ID	LOST RIVER, ID	230.00	230.00	Wood - H	20.00		1
21	BEN LOMOND, UT	NAUGHTON #1, WY	230.00	230.00	Wood - H	88.00		1
22	BEN LOMOND, UT	NAUGHTON #2, WY	230.00	230.00	Wood - H	88.00		1
23	BIRCH CREEK, UT	RAILROAD, WY	230.00	230.00	Wood - H	19.00		1
24	TREASURETON, ID	BRADY, ID	230.00	230.00	Wood - H	66.00		1
25	GLEN CANYON, AZ	SIGURD, UT	230.00	230.00	Wood - H	159.00		1
26	GONDER (ELY), UT	PAVANT, UT	230.00	230.00	Wood - H	98.00		1
27	NAUGHTON, WY	TREASURETON, ID	230.00	230.00	Wood - H	80.00		1
28	PAROWAN VALLEY, UT	SIGURD, UT	230.00	230.00	Wood - H	94.00		1
29	PAROWAN VALLEY, UT	WEST CEDAR, UT	230.00	230.00	Wood - H	26.00		1
30	PAVANT, UT	SIGURD, UT	230.00	230.00	Wood - H	43.00		1
31	ATLANTIC CITY, WY	COLUMBIA GENEVA, WY	230.00	230.00	Wood - H	1.00		1
32	PALISADES SS, WY	BLUE RIM, WY	230.00	230.00	Wood - H	4.00		1
33	BUFFALO, WY	CASPER, WY	230.00	230.00	Wood - H	107.00		1
34	GOOSE CREEK, WY	BUFFALO, WY	230.00	230.00	Wood - H	43.00		1
35	WYODAK, WY	BUFFALO, WY	230.00	230.00	Wood - H	69.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2-795 ACSR 45/7								1
2-954 ACSR 45/7								2
2-954 ACSR 54/7								3
2-1272 ACSR 36/1								4
2-1272 ACSR 36/1								5
2-954 ACSR 54/7								6
2-954 ACSR 54/7								7
2-954 ACSR 45/7								8
2-1272 ACSR 45/7								9
2-1272 ACSR 45/7								10
2-1272 ACSR 45/7								11
2-1272 ACSR 45/7								12
								13
								14
	105,594,040	985,695,543	1,091,289,583		3,032,050	828,712	3,860,762	15
								16
	105,594,040	985,695,543	1,091,289,583		3,032,050	828,712	3,860,762	17
								18
1272 ACSR 45/7								19
795 ACSR 45/7								20
795 ACSR 26/7								21
795 ACSR 26/7								22
954 ACSR 54/7								23
795 ACSR 26/7								24
954 ACSR 45/7								25
795 ACSR 45/7								26
1272 ACSR 45/7								27
795 ACSR 45/7								28
795 ACSR 45/7								29
795 ACSR 45/7								30
1272 ACSR 36/1								31
1272 ACSR 36/1								32
1272 ACSR 36/1								33
795 ACSR 26/7								34
1272 ACSR 36/1								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	JIM BRIDGER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	218.00		1
2	BITTER CREEK, WY	MONELL, WY	230.00	230.00	Wood - H	3.00		1
3	SHIRLEY BASIN, WY	DUNLAP RANCH, WY	230.00	230.00	Wood - H	12.00		1
4	ROCK SPRINGS, WY	JIM BRIDGER, WY	230.00	230.00	Wood - H	35.00		1
5	JIM BRIDGER, WY	SPENCE, WY	230.00	230.00	Wood - H	149.00		1
6	BRIDGER PUMP, WY	MANS FACE, WY	230.00	230.00	Wood - H	1.00		1
7	CASPER, WY	DAVE JOHNSTON, WY	230.00	230.00	Wood - H	36.00		1
8	CASPER, WY	RIVERTON, WY	230.00	230.00	Wood - H	110.00		1
9	DAVE JOHNSTON, WY	SPENCE, WY	230.00	230.00	Wood - H	31.00		1
10	DAVE JOHNSTON, WY	WYODAK, WY	230.00	230.00	Wood - H	69.00		1
11	MONUMENT, WY	EXXON, WY	230.00	230.00	Wood - H	13.00		1
12	FIREHOLE, WY	MONUMENT, WY	230.00	230.00	Wood - H	49.00		1
13	ROCK SPRINGS, UT	FLAMING GORGE, UT	230.00	230.00	Wood - H	55.00		1
14	YELLOWTAIL, MT	GOOSE CREEK, WY	230.00	230.00	Wood - H	59.00		1
15	NAUGHTON, WY	MONUMENT, WY	230.00	230.00	Wood - H	30.00		1
16	LIMA, WY	ROBERSON, WY	230.00	230.00	Wood - H	2.00		1
17	ROCK SPRINGS, WY	MONUMENT, WY	230.00	230.00	Wood - H	41.00		1
18	RIVERTON, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	118.00		1
19	RIVERTON, WY	THERMOPOLIS, WY	230.00	230.00	Wood - H	51.00		1
20	THERMOPOLIS, WY	YELLOWTAIL, MT	230.00	230.00	Wood - H	176.00		1
21	CHAPPEL CREEK, WY	CRAVEN CREEK, WY	230.00	230.00	Steel - SP	30.00		1
22	NAUGHTON, WY	WILLIAMS OPAL, WY	230.00	230.00	Wood - H	16.00		1
23	CHAPPEL CREEK, WY	JONAH GAS, WY	230.00	230.00	Wood - H	32.00		1
24	MINERS, WY	HIGH PLAINS, WY	230.00	230.00	Wood - H	39.00		1
25	POINT OF ROCKS, WY	ROCK SPRINGS, WY	230.00	230.00	Wood - H	27.00		1
26	MONUMENT, WY	CRAVEN CREEK, WY	230.00	230.00	Wood - H	20.00		1
27	OREGON BASIN (PAC), WY	OR BASIN (MART OIL), WY	230.00	230.00	Wood - H	1.00		1
28	WINDSTAR, WY	GLENROCK, WY	230.00	230.00	Wood - H	13.00		1
29	CHAPPEL CREEK, WY	RILEY RIDGE, WY	230.00	230.00	Wood - H	29.00	6.00	1
30	YAMSAY, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	63.00		1
31	KLAMATH FALLS, OR	MALIN, OR	230.00	230.00	Wood - H	35.00		1
32	LONE PINE, OR	KLAMATH FALLS, OR	230.00	230.00	Wood - H	76.00		1
33	LONE PINE, OR	MERIDIAN, OR	230.00	230.00	Steel SP	5.00		1
34	GRANTS PASS, OR	DIXONVILLE LINE 72, OR	230.00	230.00	Wood - H	62.00		1
35	DIXONVILLE, OR	RESTON BPA, OR	230.00	230.00	Wood - H	17.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR 36/1								1
795 ACSR 26/7								2
795 ACSR 26/7								3
1272 ACSR 36/1								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
								7
1272 ACSR 36/1								8
1272 ACSR 45/7								9
1272 ACSR 36/1								10
1272 ACSR 36/1								11
1272 ACSR 45/7								12
1272 ACSR 36/1								13
795 ACSR 26/7								14
1272 ACSR 36/1								15
1272 ACSR 45/7								16
1272 ACSR 36/1								17
1272 ACSR 36/1								18
1272 ACSR 36/1								19
1272 ACSR 36/1								20
954 ACSR 54/7								21
954 ACSR 54/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
1272 ACSR 45/7								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
1272 ACSR 45/7								28
1272 ACSR 45/7								29
795 ACSR 26/7								30
1272 ACSR 36/1								31
795 ACSR 26/7								32
1272 ACSR 36/1								33
1272 ACSR 36/1								34
795 ACSR 26/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	TAP TO HANNA, OR	NICKEL MOUNTAIN, OR	230.00	230.00	Wood - H	9.00		1
2	DIXONVILLE 500, OR	DIXONVILLE 230, OR	230.00	230.00	Wood - H	1.00		1
3	MERIDIAN, OR	GRANTS PASS, OR	230.00	230.00	Wood - H	35.00		1
4	MERIDIAN, OR	LONE PINE, OR	230.00	230.00	Wood - H		5.00	1
5	FAIRVIEW BPA, OR	ISTHMUS, OR	230.00	230.00	Wood - H	12.00		1
6	TROUTDLE-LINNEMN, OR	TROUTDALE PP&L, OR	230.00	230.00	Wood - H	1.00		1
7	TROUTDALE BPA, OR	GRESHAM PGE, OR	230.00	230.00	Steel Tower	6.00		1
8	TROUTDALE BPA, OR	LINNEMAN PGE, OR	230.00	230.00			6.00	1
9	SWIFT No. 1, WA	SWIFT No. 2, WA	230.00	230.00	Wood - H	2.00		1
10	SWIFT No. 2, WA	WOODLAND BPA SS, WA	230.00	230.00	Wood - H	23.00		1
11	FRY, OR	BETHEL, OR	230.00	230.00	Wood - H	26.00		1
12	FRY, OR	ALVEY, OR	230.00	230.00	Wood - H	45.00		1
13	ALVEY, OR	DIXONVILLE, OR	230.00	230.00	Wood - H	59.00		1
14	HURRICANE, OR	WALLA WALLA, WA	230.00	230.00	Wood - H	78.00		1
15	MCNARY BPA, WA	WALLA WALLA, WA	230.00	230.00	Wood - H	56.00		1
16	WALLA WALLA, WA	AVISTA LEWISTON, ID	230.00	230.00	Wood - H	45.00		1
17	WALLA WALLA, WA	WANAPUM (GPUD), WA	230.00	230.00	Wood - H	33.00		1
18	TALBOT, WA	MARENGO II, WA	230.00	230.00	Wood - H	7.00		1
19	JONES CANYON (BPA), OR	LEANING JUNIPER, OR	230.00	230.00	Wood - H	1.00		1
20	ROCK CREEK (BPA), WA	GOODNOE HILLS, WA	230.00	230.00	Wood - H	1.00		1
21	UNION GAP, WA	MIDWAY BPA, WA	230.00	230.00	Wood - H	39.00		1
22	WANAPUM, WA	POMONA, WA	230.00	230.00	Wood - H	37.00		1
23	POMONA, WA	UNION GAP, WA	230.00	230.00	Wood - H	8.00		1
24	230 kV costs and expenses							
25								
26	Subtotal 230kV					3,328.00	17.00	75
27								
28	ANACONDA, ID- MT	JEFFERSON PH, ID	161.00	161.00	Wood - H		90.00	1
29	ANTELOPE, ID	GOSHEN, ID	161.00	161.00	Wood - H	45.00		1
30	BONNEVILLE, ID	EAGLEROCK, ID	161.00	161.00	Wood SP	9.00		1
31	EAGLEROCK, ID	SUGARMILL, ID	161.00	161.00	Wood SP	3.00		1
32	GOSHEN, ID	GRACE, ID	161.00	161.00	Wood - H	57.00		1
33	GOSHEN, ID	RIGBY, ID	161.00	161.00	Wood - H	31.00		1
34	GOSHEN, ID	SUGAR MILL, ID	161.00	161.00	Wood SP	17.00		1
35	SUGARMILL, ID	RIGBY, ID	161.00	161.00	Wood SP	17.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
795 ACSR 26/7								1
1272 ACSR 36/1								2
1272 ACSR 36/1								3
1272 ACSR 54/19								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
954 ACSR 45/7								7
900 ACSR 54/7								8
954 ACSR 45/7								9
954 ACSR 45/7								10
1272 ACSR 36/1								11
1272 ACSR 36/1								12
1272 ACSR 36/1								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
1272 ACSR 36/1								16
1272 ACSR 36/1								17
795 ACSR 26/7								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
954 ACSR 45/7								21
1272 ACSR 36/1								22
1272 ACSR 36/1								23
	15,529,412	349,202,441	364,731,853	23,014	5,295,061	476,724	5,794,799	24
								25
	15,529,412	349,202,441	364,731,853	23,014	5,295,061	476,724	5,794,799	26
								27
250HH CU /7								28
397.5 ACSR 26/7								29
954 ACSR 45/7								30
954 ACSR 45/7								31
250HH CU /7								32
397.5 ACSR 26/7								33
795 AAC /37								34
397.5 ACSR 26/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	EAGLEROCK, ID	GOSHEN, ID	161.00	161.00	Wood - H	12.00		1
2	YELLOWTAIL, MT	RIMROCK, MT	161.00	161.00	Wood - H	46.00		1
3	RIGBY, ID	JEFFERSON, ID	161.00	161.00	Wood SP	18.00		1
4	161 kV costs and expenses							
5								
6	Subtotal 161kV					255.00	90.00	11
7								
8	WHEELON, UT	AMERICAN FALLS, ID	138.00	138.00	Wood - H	82.00		1
9	OQUIRRH, UT	TOOELE, UT	138.00	138.00	Wood - SP	21.00		1
10	OQUIRRH, UT	BARNEY, UT	138.00	138.00	Wood - H	5.00		1
11	ANSCHTZ CO-GEN, WY	EVANSTON, WY	138.00	138.00	Wood - H	22.00		1
12	ANTELOPE, ID	SCOVILLE #1, ID	138.00	138.00	Wood - H	1.00		1
13	ANTELOPE, ID	SCOVILLE #2, ID	138.00	138.00	Wood - H	1.00		1
14	ASHLEY, UT	CARBON, UT	138.00	138.00	Wood - H	92.00		1
15	ASHLEY, UT	VERNAL, UT	138.00	138.00	Wood - H	12.00		1
16	BEKER IND, ID	THREEMILE KNOLL, ID	138.00	138.00	Wood - H	4.00		1
17	BEN LOMOND, UT	BRIGHAM CITY, UT	138.00	138.00	Wood - H	14.00		1
18	BEN LOMOND #1, UT	EL MONTE, UT	138.00	138.00	Steel - SP	14.00		1
19	BEN LOMOND #2, UT	EL MONTE, UT	138.00	138.00			13.00	1
20	BEN LOMOND, UT	HONEYVILLE, UT	138.00	138.00			22.00	1
21	BEN LOMOND, UT	CLINTON, UT	138.00	138.00			13.00	1
22	BEN LOMOND, UT	ANGEL, UT	138.00	138.00	Steel - SP	28.00		1
23	BEN LOMOND, UT	W ZIRCONIUM, UT	138.00	138.00	Wood - SP	14.00		1
24	BEN LOMOND, UT	WHEELON, UT	138.00	138.00	Steel Tower	42.00		1
25	BRIGHAM CITY, UT	WHEELON, UT	138.00	138.00	Wood - H	24.00		1
26	CAMERON, UT	PAROWAN, UT	138.00	138.00	Wood - H	35.00		1
27	CAMERON, UT	SIGURD, UT	138.00	138.00	Wood - H	64.00		1
28	CARBON, UT	HELPER #1, UT	138.00	138.00	Wood - H	2.00		1
29	CARBON, UT	HELPER #2, UT	138.00	138.00	Wood - H	2.00		1
30	CARBON #1, UT	SPANISH FORK, UT	138.00	138.00	Steel Tower	54.00		1
31	CARBON #2, UT	SPANISH FORK, UT	138.00	138.00			52.00	1
32	THREEMILE KNOLL, ID	GRACE #1, ID	138.00	138.00	Wood - H	17.00		1
33	THREEMILE KNOLL, ID	GRACE #2, ID	138.00	138.00	Wood - H	17.00		1
34	THREEMILE KNOLL, ID	MONSANTO 1, ID	138.00	138.00	Wood - H	2.00		1
35	THREEMILE KNOLL, ID	MONSANTO 2, ID	138.00	138.00	Wood - SP	2.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 45/7								1
556.5 ACSR 26/7								2
397.5 ACSR 26/7								3
	623,490	20,224,837	20,848,327		581,180	2,788	583,968	4
								5
	623,490	20,224,837	20,848,327		581,180	2,788	583,968	6
								7
250 CUHD /12								8
795 ACSR 45/7								9
795 ACSR 26/7								10
795 ACSR 26/7								11
397.5 ACSR 26/7								12
397.5 ACSR 26/7								13
397.5 ACSR 26/7								14
397.5 ACSR 26/7								15
397.5 ACSR 26/7								16
1272 ACSR 45/7								17
795 ACSR 45/7								18
795 ACSR 45/7								19
250 CUHD /12								20
250 CUHD /12								21
397.5 ACSR 26/7								22
795 AAC /37								23
250 CUHD /12								24
795 ACSR 26/7								25
397.5 ACSR 26/7								26
397.5 ACSR 26/7								27
954 ACSR 54/7								28
556.5 ACSR 26/7								29
795 ACSR 26/7								30
1272 ACSR 45/7								31
250 CUHD /12								32
1272 ACSR 45/7								33
1272 AAC /61								34
1272 ACSR 45/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	CLEAR CREEK, WY	PAINTER, WY	138.00	138.00	Wood - SP	5.00		1
2	COLUMBIA, UT	MOUNDS SWRK, UT	138.00	138.00	Wood - H	7.00		1
3	TAP TO SOUTHEAST, UT	SOUTHEAST, UT	138.00	138.00	Wood - SP	6.00		1
4	COTTONWOOD, UT	HAMMER, UT	138.00	138.00	Wood - SP	5.00		1
5	COTTONWOOD, UT	SILVER CREEK, UT	138.00	138.00	Wood - SP	29.00		1
6	CUTLER, UT	WHEELON, UT	138.00	138.00	Wood - SP	1.00		1
7	WEST CEDAR, UT	ENTERPRISE VALLEY, UT	138.00	138.00	Wood - H	33.00		1
8	EVANSTON, WY	RAILROAD, WY	138.00	138.00	Wood - SP	3.00		1
9	FRANKLIN, UT	SMITHFIELD, UT	138.00	138.00	Wood - SP	25.00		1
10	FRANKLIN, ID	TREASURETON, ID	138.00	138.00	Wood - SP	10.00		1
11	JORDAN, UT	MCCLELLAND, UT	138.00	138.00	Wood - SP	5.00		1
12	GADSBY, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
13	JORDAN, UT	TERMINAL, UT	138.00	138.00	Wood - SP	6.00		1
14	TIMP, UT	HALE, UT	138.00	138.00	Steel - SP	4.00		1
15	ABAJO, UT	PINTO, UT	138.00	138.00	Wood - H	44.00		1
16	ONIEDA, ID	GRACE, ID	138.00	138.00	Wood - H	19.00		1
17	TREASURETON, ID	GRACE, ID	138.00	138.00	Steel Tower	25.00		1
18	TREASURETON, ID	GRACE, ID	138.00	138.00			25.00	1
19	NEBO, UT	DRY CREEK, UT	138.00	138.00	Wood - H	37.00		1
20	WESTFIELD, UT	HALE, UT	138.00	138.00	Wood - H	13.00		1
21	NINETY SOUTH, UT	DUMAS, UT	138.00	138.00	Wood - SP	6.00		1
22	DUMAS, UT	WESTFIELD, UT	138.00	138.00	Wood - SP	18.00		1
23	TRI-CITY, UT	AMERICAN FORK, UT	138.00	138.00	Wood - H	15.00		1
24	TIMP, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	23.00		1
25	HALE, UT	TANNER, UT	138.00	138.00	Wood - H	7.00		1
26	MOUNDS SWRK, UT	HELPER, UT	138.00	138.00	Wood - H	29.00		1
27	HONEYVILLE, UT	WHEELON, UT	138.00	138.00			14.00	1
28	HUNTINGTON, UT	MCFADDEN, UT	138.00	138.00	Wood - H	7.00		1
29	TERMINAL, UT	KENNECOTT, UT	138.00	138.00	Steel - SP	9.00		1
30	KILN, UT	NEBO, UT	138.00	138.00	Wood - H	30.00		1
31	MCCLELLAND, UT	MIDVALLEY, UT	138.00	138.00	Wood - SP	6.00		1
32	MOUNDS SWRK, UT	MOAB, UT	138.00	138.00	Wood - H	83.00		1
33	MOAB, UT	PINTO, UT	138.00	138.00	Wood - H	68.00		1
34	NAUGHTON, WY	NGPL, WY	138.00	138.00	Wood - H	36.00		1
35	NAUGHTON, WY	PAINTER, WY	138.00	138.00	Wood - H	46.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR 26/7								1
266.8 ACSR 26/7								2
795 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
250 CUHD /12								6
397.5 ACSR 26/7								7
795 ACSR 26/7								8
397.5 ACSR 26/7								9
795 ACSR 45/7								10
795 AAC /37								11
1272 ACSR 45/7								12
1272 AAC /61								13
								14
397.5 ACSR 26/7								15
250 CUHD /12								16
250 CUHD /12								17
250 CUHD /12								18
1272 ACSR 45/7								19
795 ACSR 26/7								20
795 AAC /37								21
795 ACSR 26/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
1272 ACSR 45/7								25
397.5 ACSR 26/7								26
250 CUHD /12								27
397.5 ACSR 26/7								28
795 ACSR 26/7								29
397.5 ACSR 26/7								30
795 ACSR 26/7								31
397.5 ACSR 26/7								32
397.5 ACSR 26/7								33
795 ACSR 26/7								34
795 ACSR 26/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	NGPL, WY	TAP TO STR 204, WY	138.00	138.00	Wood - H	12.00		1
2	CANYON COMPRESS, WY	WHITNEY, WY	138.00	138.00	Wood - H	1.00		1
3	NINETY SOUTH, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	10.00		1
4	TAYLORSVILLE, UT	NINETY SOUTH, UT	138.00	138.00	Wood - SP	6.00	2.00	1
5	MID VALLEY, UT	NINETY SOUTH, UT	138.00	138.00	Wood - H	9.00		1
6	NUCOR STEEL, UT	WHEELON, UT	138.00	138.00	Wood - H	14.00		1
7	ONEIDA, ID	OVID, ID	138.00	138.00	Wood - H	23.00		1
8	TREASURETON, ID	ONEIDA, ID	138.00	138.00	Wood - H	6.00		1
9	PAINTER, WY	RAILROAD, WY	138.00	138.00	Wood - H	7.00		1
10	PAROWAN, UT	WEST CEDAR, UT	138.00	138.00	Wood - H	21.00		1
11	TAP TO ANGEL SOUTH, UT	TAP TO PARRISH, UT	138.00	138.00			13.00	1
12	PARRISH #1, UT	TERMINAL, UT	138.00	138.00	Steel SP	16.00		1
13	PARRISH #2, UT	TERMINAL, UT	138.00	138.00			14.00	1
14	RAILROAD, WY	WHITNEY, WY	138.00	138.00	Wood - H	16.00		1
15	ROY STR, UT	ANGEL, UT	138.00	138.00			10.00	1
16	BEN LOMOND, UT	SYRACUSE, UT	138.00	230.00	Steel Tower	25.00		1
17	TERMINAL, UT	ROWLEY, UT	138.00	138.00	Wood - H	56.00		1
18	GREEN CANYON, UT	WHEELON, UT	138.00	138.00	Wood - SP	19.00		1
19	SPANISH FORK, UT	TANNER, UT	138.00	138.00	Wood - H	10.00		1
20	TAP TO ANGEL NORTH, UT	TAP TO PARRISH, UT	138.00	138.00			13.00	1
21	TERMINAL, UT	MIDVALLEY, UT	138.00	138.00	Wood - H	7.00		1
22	TERMINAL, UT	MIDVALLEY, UT	138.00	138.00	Steel - SP	7.00		1
23	TERMINAL, UT	TOOELE, UT	138.00	138.00	Wood - H	24.00	6.00	1
24	WHEELON #103, UT	TREASURETON, ID	138.00	138.00	Steel Tower	29.00		1
25	WHEELON #104, UT	TREASURETON, ID	138.00	138.00			29.00	1
26	WHEELON #105, UT	TREASURETON, ID	138.00	138.00	Wood - H	29.00		1
27	KCC BARNEY, UT	KCCGRIND, UT	138.00	138.00	Wood - H	1.00		1
28	TERMINAL, UT	LAKE PARK, UT	138.00	138.00	Wood - H	3.00		1
29	LAKE PARK, UT	WEST VALLEY, UT	138.00	138.00	Wood - H	3.00		1
30	WEST VALLEY, UT	OQUIRRH, UT	138.00	138.00	Wood - H	7.00		1
31	OQUIRRH, UT	KCC BINGHAM, UT	138.00	138.00	Wood - H	8.00		1
32	WEST CEDAR, UT	THREE PEAKS, UT	138.00	138.00	Wood - SP	20.00		1
33	HALE, UT	SPANISH FORK, UT	138.00	138.00	Wood - H	18.00		1
34	MID VALLEY, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	4.00	2.00	1
35	PARRISH #105, UT	TERMINAL, UT	138.00	138.00	Steel - SP	14.00		1
36					TOTAL	15,957.00	806.00	264

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 ACSR 26/7								1
795 ACSR 26/7								2
795 ACSR 26/7								3
795 AAC /37								4
1272 ACSR 45/7								5
397.5 ACSR 26/7								6
336.4 ACSR 26/7								7
250 CUHD /12								8
1272 ACSR 45/7								9
397.5 ACSR 26/7								10
795 AAC /37								11
795 ACSR 45/7								12
795 ACSR 26/7								13
795 ACSR 26/7								14
795 AAC /37								15
795 AAC /37								16
795 AAC /37								17
397.5 ACSR 26/7								18
1272 ACSR 45/7								19
795 AAC /37								20
1272 ACSR 45/7								21
1272 AAC /61								22
397.5 ACSR 26/7								23
250 CUHD /12								24
250 CUHD /12								25
250 CUHD /12								26
795 ACSR 26/7								27
								28
								29
								30
								31
795 ACSR 26/7								32
1272 ACSR 45/7								33
1272 AAC /61								34
795 ACSR 45/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	COLUMBIA, UT	SUNNYSIDE, UT	138.00	138.00	Wood-H	2.00		1
2	JERUSALM, UT	NEBO, UT	138.00	138.00	Wood - H	26.00		1
3	HALE, UT	MIDWAY, UT	138.00	138.00	Wood - H	19.00		1
4	QUARRY TAP, UT	DUMAS, UT	138.00	138.00	U/G	5.00		1
5	HONEYVILLE, UT	LAMPO, UT	138.00	138.00	Wood - H	25.00		1
6	GADSBY, UT	JORDAN, UT	138.00	138.00	Wood - SP	1.00		1
7	MID VALLEY, UT	COTTONWOOD, UT	138.00	138.00	Wood - SP	5.00		1
8	NINETY SOUTH, UT	SANDY, UT	138.00	138.00	Steel - SP	1.00		1
9	MICRON, UT	CAMP WILLIAMS, UT	138.00	138.00			9.00	1
10	MCFADDEN, UT	BLACKHAWK, UT	138.00	138.00	Wood - H	11.00		1
11	TAP TO SANDY (STR 60), UT	SANDY, UT	138.00	138.00	Steel - SP	6.00		1
12	EL MONTE, UT	STR 30B, UT	138.00	138.00	Steel - SP	4.00		1
13	EL MONTE, UT	PIONEER, UT	138.00	138.00	Steel - SP	1.00		1
14	SYRACUSE, UT	CLEARFIELD SOUTH, UT	138.00	138.00	Steel - SP	1.00		1
15	MID VALLEY, UT	COTTONWOOD, UT	138.00	138.00	Steel - SP	5.00		1
16	HAMMER, UT	BUTLERVILLE, UT	138.00	138.00			2.00	1
17	BUTLERVILLE, UT	NINETY SOUTH, UT	138.00	138.00	Steel - SP	9.00		1
18	KEARNS, UT	TAYLORSVILLE, UT	138.00	138.00	Wood - SP	2.00		1
19	SILVER CREEK SUB, UT	JORDANELLE SUB, UT	138.00	138.00	Wood - SP	10.00		1
20	KEARNS, UT	WEST VALLEY, UT	138.00	138.00	Wood - SP	2.00		1
21	RIVERDALE, UT	105 TAP, UT	138.00	138.00	Steel - SP		21.00	1
22	OQUIRRH, UT	SUNRISE - TRI CITY, UT	138.00	138.00	Steel - SP	25.00		1
23	BANGERTER, UT	TRI-CITY, UT	138.00	138.00			23.00	1
24	DYNAMO, UT	TRI-CITY #1, UT	138.00	138.00	Steel - SP	2.00		1
25	TIMP #1, UT	DYNAMO, UT	138.00	138.00	Steel - SP	2.00		1
26	DYNAMO, UT	TRI-CITY #2, UT	138.00	138.00			3.00	1
27	TIMP #2, UT	DYNAMO, UT	138.00	138.00			2.00	1
28	MIDDLETON, UT	ST. GEORGE, UT	138.00	138.00	Wood - H	1.00		1
29	BRIDGERLAND, UT	GREEN CANYON, UT	138.00	138.00	Wood - SP	16.00		1
30	SYRACUSE, UT	PARRISH, UT	138.00	230.00	Steel Tower	15.00		1
31	BONANZA, UT	CHAPITA, UT	138.00	138.00	Wood - H	8.00		1
32	CENTRAL, UT	ST GEORGE #1, UT	138.00	345.00	Steel - SP	20.00		1
33	CENTRAL, UT	ST GEORGE #2, UT	138.00	345.00			20.00	1
34	EBAY TAP, UT	OQUIRRH, UT	138.00	138.00	Wood - SP	1.00		1
35	PARRISH, UT	TAP TO NSALT LAKE, UT	138.00	138.00	Steel - SP		8.00	1
36					TOTAL	15,957.00	806.00	264

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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
397.5 ACSR 26/7								2
397.5 ACSR 26/7								3
1750 AL XLPE UG								4
397.5 ACSR 26/7								5
1272 AAC /61								6
								7
795 AAC /37								8
795 ACSR 26/7								9
795 ACSR 26/7								10
795 AAC /37								11
1272 ACSR 45/7								12
1272 ACSR 45/7								13
1272 ACSR 45/7								14
								15
795 ACSR 26/7								16
795 AAC /37								17
500 AAC /19								18
795 ACSR 26/7								19
								20
795 ACSR 26/7								21
								22
								23
795 ACSR 26/7								24
								25
795 ACSR 26/7								26
								27
397.5 ACSR 26/7								28
1272 ACSR 45/7								29
1272 ACSR 45/7								30
795 ACSR 26/7								31
2-1272 ACSR 45/7								32
2-1272 ACSR 45/7								33
795 ACSR 26/7								34
795 ACSR 26/7								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	138 kV costs and expenses							
2								
3	Subtotal 138kV					1,887.00	316.00	133
4								
5	All 115kV Lines					1,603.00		
6	All 69kV Lines					3,000.00		
7	All 57kV Lines					113.00		
8	All 46kV Lines					2,573.00		
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								
35								
36					TOTAL	15,957.00	806.00	264

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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)	
	18,064,040	313,621,849	331,685,889	29,945	2,238,892	137,999	2,406,836	1
								2
	18,064,040	313,621,849	331,685,889	29,945	2,238,892	137,999	2,406,836	3
								4
	4,145,005	156,245,499	160,390,504	95,468	4,052,628	555,244	4,703,340	5
	6,485,643	237,525,550	244,011,193	16,020	3,283,339	204,569	3,503,928	6
	45,458	9,799,269	9,844,727		74,537	3,585	78,122	7
	8,596,739	210,877,840	219,474,579	94,604	2,402,961	64,426	2,561,991	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
								35
	173,359,503	2,552,922,302	2,726,281,805	259,051	22,369,881	2,549,553	25,178,485	36

Schedule Page: 422 Line No.: 1 Column: a

Certain transmission lines reported on pages 422-423 are part of exchange agreements with various third parties. Refer to the footnotes on pages 328-330 of this FERC Form No.1 for further discussion.

Schedule Page: 422 Line No.: 2 Column: a

The Meridian - Klamath Co-Gen, Klamath Co-Gen - Captain Jack, Captain Jack - Malin and Midpoint - Malin 500-kV lines comprise what is referred to as the Midpoint to Meridian transmission project.

Schedule Page: 422 Line No.: 3 Column: a

See Footnote on page 422 for column (a) line 2.

Schedule Page: 422 Line No.: 4 Column: a

The Alvey - Dixonville 500-kV 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%. Plant 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 500-kV 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%. Plant 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.: 6 Column: a

See Footnote on page 422 for column (a) line 2.

Schedule Page: 422 Line No.: 7 Column: a

See Footnote on page 422 for column (a) line 2.

Schedule Page: 422 Line No.: 8 Column: a

The Colstrip 4 - Switchyard 500-kV 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 500-kV 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 500-kV 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 500-kV 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 500-kV 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: 422.1 Line No.: 13 Column: i

2-1557.4 ACSR/TW 36/7

Schedule Page: 422.1 Line No.: 14 Column: i

2-1557.4 ACSR/TW 36/7

Schedule Page: 422.2 Line No.: 7 Column: a

A 1.5 mile segment of the Casper - Dave Johnston 230-kV line is jointly owned by the respondent and Black Hills Power. Ownership of the line is as follows: PacifiCorp 43.75%, Black Hills Power 56.25%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422.2 Line No.: 7 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.5 Line No.: 14 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 28 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 29 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 30 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 31 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 7 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 15 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 20 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 22 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 23 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 25 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 27 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 32 Column: a

The Central – St. George transmission line operating at 138 kV is jointly owned by the respondent and Utah Associated Municipal Power Systems (“UAMPS”). Ownership of the line is as follows: PacifiCorp 54.62%, UAMPS 45.38%. Plant cost and operation and maintenance costs reported for this line reflects the respondent's share.

Schedule Page: 422.7 Line No.: 33 Column: a

See Footnote on page 422.7 for column (a) line 35.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	PARRISH TAP, UT	SKYPARK, UT	7.00	Steel - SP	9.00	2	2
2	LIMA, WY	ROBERSON, WY	2.00	Wood - H	12.00	1	1
3	CHIMNEY BUTTE TAP, WY	RILEY RIDGE, WY	12.00	Wood - H	12.00	1	1
4							
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							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		21.00		33.00	4	4

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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.
795	ACSR	Vertical 12'	138		839,114	209,778		1,048,892	1
1272	ACSR	Horizon 20'	230		-265	-183		-448	2
1272	ACSR	Horizon 20'	230		1,936,956	1,805,231		3,742,187	3
									4
									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
									35
									36
									37
									38
									39
									40
									41
									42
									43
					2,775,805	2,014,826		4,790,631	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 PacifiCorp	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
25	1					2
6	1					3
1	3					4
1	3					5
4	3					6
	1					7
7	3					8
6	1					9
9	1					10
12	1					11
1	1					12
8	3					13
4	3					14
9	3					15
12	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
12	1					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
6	3					34
1	1					35
5	3					36
1	3					37
1	3					38
20	1					39
6	6					40

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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 SUB	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	115.00	69.00	12.47
18	COPCO #2 SUB	TRANSMISSION-ATTENDE	115.00	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		1058.00	537.90	24.94
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	CLEMENTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CLIFTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	COVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
8	3					1
25	1					2
3	3					3
4	3					4
324	102					5
						6
						7
31	4					8
4	3					9
95	2					10
130	9					11
						12
						13
5	3					14
27	6	2				15
375	2					16
122	5	1				17
51	4					18
19	3					19
150	2					20
19	1					21
37	3					22
805	29	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
5	1					38
4	1					39
6	1					40

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	DOWNEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	DUBOIS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	EASTMONT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	EGIN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	EIGHT MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	GEORGETOWN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	GRACE CITY SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
8	HAMER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	HAYES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	HENRY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	HOLBROOK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	HOOPES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	HORSLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	IDAHO FALLS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	INDIAN CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	JEFFCO SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
17	KETTLE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
18	LAVA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	LUND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	MCCAMMON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	MENAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	MILLER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	MONTPELIER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	MOODY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	NEWDALE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	OSGOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	PRESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	RAYMOND SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	RENO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	REXBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	RIRIE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	ROBERTS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	RUBY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	SAND CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	SANDUNE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
37	SHELLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	SMITH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	SOUTH FORK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	SPUD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
12	1					2
14	1					3
14	1					4
2	1					5
6	1					6
5	1					7
14	1					8
9	1					9
2	1					10
6	1					11
9	1					12
4	1					13
20	1					14
2	1					15
22	1					16
14	1					17
2	1					18
5	1					19
3	1					20
11	1					21
20	1					22
5	1					23
7	1					24
14	1					25
20	1					26
20	1					27
13	1					28
2	1					29
20	1					30
32	2					31
9	1					32
7	1					33
7	1					34
40	2					35
20	1					36
20	1					37
20	1					38
14	1					39
7	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	ST. CHARLES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	SUGAR CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	SUNNYDELL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	TANNER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	TARGHEE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	THORNTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	UCON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	WATKINS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	WEBSTER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	WESTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	WINDSPER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
12	Total		4002.00	872.70	
13	Number of Substations-65				
14					
15	CINDER BUTTE SUB	T/D-UNATTENDED	161.00	12.47	
16	MALAD SUB	T/D-UNATTENDED	138.00	46.00	12.47
17	MUD LAKE SUB	T/D-UNATTENDED	69.00	12.47	
18	RIGBY SUB	T/D-UNATTENDED	161.00	12.47	69.00
19	SAINT ANTHONY SUB	T/D-UNATTENDED	69.00	46.00	12.47
20	Total		598.00	129.41	93.94
21	Number of Substations-5				
22					
23	GRACE HYDRO	TRANSMISSION-ATTENDE	138.00	46.00	6.60
24	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
25	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	12.47
26	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	2.40	12.47
27	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
28	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
29	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
30	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
31	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
32	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	46.00
33	JEFFERSON SUB	TRANSMISSION-UNATTEN	161.00	69.00	
34	LIFTON HYDRO	TRANSMISSION-UNATTEN	69.00	2.30	
35	ONEIDA SUB	TRANSMISSION-UNATTEN	138.00	25.00	
36	OVID SUB	TRANSMISSION-UNATTEN	138.00	69.00	
37	SCOVILLE SUB	TRANSMISSION-UNATTEN	138.00	69.00	
38	SUGARMILL SUB	TRANSMISSION-UNATTEN	161.00	46.00	69.00
39	THREEMILE KNOLL SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
40	TREASURETON SUB	TRANSMISSION-UNATTEN	230.00	138.00	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
13	1					2
13	1					3
4	1					4
4	1					5
7	1					6
7	1					7
14	1					8
20	1					9
4	1					10
20	1					11
723	67					12
						13
						14
60	2	1				15
71	4	1				16
14	1					17
189	4					18
40	2					19
374	13	2				20
						21
						22
115	4					23
75	1	1				24
445	3					25
18	3					26
67	1					27
67	1					28
67	1					29
25	3					30
75	1					31
763	8	1				32
233	3					33
6	2					34
40	2					35
30	1					36
76	2					37
169	3					38
700	1					39
533	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	Total		3128.00	1271.70	205.01
2	Number of Substations-18				
3					
4	MONTANA				
5	YELLOWTAIL SUB	TRANSMISSION-UNATTEN	230.00	161.00	
6	Total		230.00	161.00	
7	Number of Substations-1				
8					
9	OREGON				
10	26TH STREET	DISTRIBUTION-UNATTEN	20.80	4.16	
11	35TH STREET	DISTRIBUTION-UNATTEN	20.80	2.40	
12	AGNESS AVE	DISTRIBUTION-UNATTEN	115.00	12.47	
13	ALDERWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	ARLINGTON	DISTRIBUTION-UNATTEN	69.00	12.47	
15	ATHENA	DISTRIBUTION-UNATTEN	69.00	12.47	
16	BANDON TIE SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
17	BEACON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	BEALL LANE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	BEATTY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	BELKNAP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	BLALOCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	BLOSS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	BLY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	BOISE CASCADE SUB	DISTRIBUTION-UNATTEN	69.00	11.00	
25	BONANZA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	BOND STREET SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
27	BROOKHURST SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	BROWNSVILLE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
29	BRYANT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	BUCHANAN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
31	BUCKAROO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	CAMPBELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	CANNON BEACH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	CARNES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	CASEBEER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
36	CAVEMAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	CHERRY LANE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	CHILOQUIN MARKET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CHINA HAT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	CIRCLE BLVD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
3504	42	2				1
						2
						3
						4
100	1					5
100	1					6
						7
						8
						9
5	1					10
30	6					11
25	1					12
45	2					13
5	1					14
9	1					15
8	3	1				16
11	3					17
25	1					18
6	1					19
40	2					20
2	3					21
32	2					22
8	3					23
3	1					24
8	3					25
25	1					26
50	2					27
13	1					28
34	2					29
40	2					30
34	2					31
20	2					32
13	1					33
9	3					34
20	1					35
45	2					36
25	1					37
5	3					38
25	1					39
80	2					40

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	CLINE FALLS HYDRO	DISTRIBUTION-UNATTEN	12.47	2.40	
3	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
5	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
6	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
7	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
8	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
9	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
10	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	CUTLER CITY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
15	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
17	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
18	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
20	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
21	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
31	GAZLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
33	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
34	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
38	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
40	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
45	2					1
1	3					2
20	1					3
10	3					4
9	2					5
55	2	1				6
20	1					7
40	2					8
5	1					9
25	2					10
20	1					11
25	1					12
13	1					13
2	3					14
25	1					15
50	2					16
75	3					17
13	1					18
50	2					19
7	1					20
13	1					21
20	1					22
45	2					23
20	1					24
19	2					25
13	1					26
25	1					27
21	4					28
5	3					29
20	1					30
8	4					31
25	2					32
5	1					33
13	1					34
11	3					35
6	1					36
20	1					37
45	2					38
1	4					39
25	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
7	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
13	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
17	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
21	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
22	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
27	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
30	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
31	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
34	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	MEDFORD	DISTRIBUTION-UNATTEN	69.00	12.47	
36	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
8	3					2
13	1					3
6	3					4
40	1					5
45	2					6
20	1					7
75	3					8
50	2					9
40	2					10
20	1					11
9	1					12
13	1					13
2	1					14
20	1					15
75	2					16
13	1					17
20	1					18
20	1					19
6	1	1				20
25	2					21
3	3					22
40	2					23
6	1					24
50	2					25
13	3					26
40	2					27
105	3					28
40	2					29
9	2					30
25	2					31
25	1					32
20	1					33
20	1					34
67	8					35
45	2					36
17	6					37
	1					38
6	3					39
2	3					40

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	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	MYRTLE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
5	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
11	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
13	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
19	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
20	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	RIDDLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
25	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
27	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
29	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
31	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
34	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
35	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
36	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
37	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
39	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
100	4					1
14	1					2
9	1					3
4	1					4
9	1					5
45	2					6
8	1					7
75	2					8
45	2					9
1	1	1				10
40	2					11
39	2					12
46	7	1				13
22	2					14
6	1					15
50	2					16
11	3					17
50	2					18
1	3					19
50	2					20
14	1					21
25	1	1				22
25	2					23
50	2					24
9	3					25
25	1					26
9	1					27
9	1					28
45	2					29
70	3					30
8	1					31
40	2					32
9	1					33
1	3					34
25	1					35
18	2					36
9	1					37
20	1					38
6	3					39
40	2					40

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	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	
3	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
5	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
6	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
7	TALENT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
17	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
22	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
23	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	WESTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
29	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
31	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	Total		15463.54	2509.83	195.00
33	Number of Substations-182				
34					
35	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
36	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
37	ASHLAND MTN AVE SUB	T/D-UNATTENDED	115.00	69.00	12.47
38	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
39	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
40	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
55	2					1
	1					2
50	2					3
25	1					4
42	2					5
12	1					6
50	2					7
25	1					8
1	1					9
10	1					10
13	3					11
20	1					12
25	2					13
50	2					14
25	1					15
40	2					16
20	1					17
6	1					18
12	3					19
25	2					20
2	3					21
3	1					22
50	2					23
22	2					24
22	9					25
40	2					26
60	3					27
28	3					28
22	3					29
25	1					30
36	2					31
4541	351	6				32
						33
						34
177	9					35
65	2					36
70	2					37
31	3					38
70	2					39
133	4					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
2	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47
3	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
4	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
5	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
6	Total		1334.00	420.44	338.82
7	Number of Substations-11				
8					
9	CLEARWATER #1 HYDRO PLANT	TRANSMISSION-ATTENDE	138.00	6.90	
10	FISH CREEK HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
11	JC BOYLE HYDRO	TRANSMISSION-ATTENDE	230.00	11.00	
12	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.30	12.50	
13	LEMOLO #2 HYDRO	TRANSMISSION-ATTENDE	115.00	12.00	
14	PROSPECT 1 HYDRO	TRANSMISSION-ATTENDE	69.00	2.30	
15	PROSPECT 2 HYDRO	TRANSMISSION-ATTENDE	69.00	6.60	
16	PROSPECT 3 HYDRO	TRANSMISSION-ATTENDE	69.00	12.47	
17	TOKETEE HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
18	BEND HYDRO PLANT	TRANSMISSION-UNATTEN	4.16	2.40	
19	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
20	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
21	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
22	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
23	DAYS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
24	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
25	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
26	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
27	EAGLE POINT HYDRO	TRANSMISSION-UNATTEN	115.00	2.40	
28	EAST SIDE HYDRO	TRANSMISSION-UNATTEN	46.00	12.47	
29	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
30	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
31	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
32	GREEN SPRINGS PLANT/SUB	TRANSMISSION-UNATTEN	115.00	69.00	
33	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
34	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
35	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
36	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
38	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
39	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
40	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
162	5					1
39	4					2
400	4					3
40	2					4
75	5					5
1262	42					6
						7
						8
17	3					9
13	3					10
89	2	1				11
2	3	1				12
40	4					13
5	3					14
40	6	1				15
10	6					16
50	9					17
30	3					18
75	1					19
119	4					20
66	2					21
67	3					22
50	1					23
75	1					24
344	6					25
650	3	1				26
3	1					27
3	3					28
7	3					29
500	2					30
473	5					31
19	3					32
29	2					33
250	1					34
33	1					35
251	6	1				36
732	10					37
1300	6	1				38
50	1					39
114	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
2	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
3	POWERDALE PLANT	TRANSMISSION-UNATTEN	69.00	7.20	
4	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
5	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
6	SLIDE CREEK HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
7	SODA SPRINGS HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
8	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
9	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
10	WALLOWA FALLS HYDRO	TRANSMISSION-UNATTEN	20.80		
11	Total		6970.26	2634.04	362.27
12	Number of Substations-42				
13					
14	UTAH				
15	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
16	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
19	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
23	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
29	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	BRICKYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
35	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
38	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	CANYONLANDS 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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
150	1					1
250	1					2
8	3	1				3
46	4					4
50	1					5
21	3					6
13	3					7
500	3					8
100	2					9
1	3					10
6645	132	7				11
						12
						13
						14
30	1					15
30	1					16
12	1					17
30	1					18
45	2					19
11	1					20
30	1					21
1	1					22
3	1					23
50	2					24
17	2					25
2	1					26
11	1					27
2	3					28
1	3					29
9	1					30
4	1					31
14	1					32
9	1					33
26	2					34
6	1					35
60	3					36
11	3					37
9	1					38
12	1					39
1	1					40

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	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	CARBIDE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
3	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
5	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
6	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
8	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
9	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
19	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
21	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
25	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
28	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
31	DESERET SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
32	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	DIXIE DEER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
35	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
3	1					2
6	1					3
30	1					4
25	1					5
22	1					6
9	1					7
30	1					8
50	2					9
3	1					10
4	1					11
	3					12
60	2					13
50	2					14
4	1					15
20	2					16
30	1					17
106	4					18
1	3					19
30	1					20
30	1					21
3	1					22
2	3					23
30	1					24
22	1					25
30	1					26
42	1					27
55	2					28
6	1					29
48	3					30
2	1					31
4	1					32
60	2					33
2	1					34
23	2					35
30	1					36
6	1					37
60	2					38
20	1					39
19	2					40

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	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	ELK MEADOWS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	FERRON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
13	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
14	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	FREEDOM SUBSTATION	DISTRIBUTION-UNATTEN	46.00	7.20	
18	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
22	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
23	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	GUNLOCK HYDRO	DISTRIBUTION-UNATTEN	34.50	2.30	
27	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
29	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
31	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	HIAWATHA SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
34	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	HOGLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
5	1					1
3	1					2
2	1					3
3	3					4
25	1					5
14	1					6
10	1					7
3	1					8
30	1					9
1	2					10
5	1					11
6	1					12
50	2					13
4	1					14
2	1					15
7	1					16
	1					17
22	1					18
13	1					19
28	1	1				20
30	1					21
30	1					22
2	1					23
50	2					24
24	1					25
1	1					26
11	2					27
60	2					28
3	1					29
3	3					30
4	1					31
30	1					32
4	3					33
25	1					34
50	2					35
22	1					36
4	1					37
32	2					38
22	1					39
13	2					40

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
2	IRON SPRINGS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
3	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	IVINS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
6	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
14	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	LARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	LISBON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
25	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
27	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	MANILA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	MANTUA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
39	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	1					1
5	3					2
2	1					3
22	1					4
13	2					5
30	1					6
30	1					7
2	3					8
2	1					9
5	1					10
7	1					11
60	2					12
7	1					13
53	2					14
6	1					15
40	2					16
1	1					17
14	1					18
20	1					19
20	1					20
4	1					21
20	1					22
	1					23
1	1					24
20	1					25
1	1					26
4	1					27
12	1					28
30	1					29
22	1					30
2	1					31
14	1					32
20	1					33
3	1					34
9	1					35
6	1					36
20	1					37
42	2					38
57	4					39
30	1					40

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	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
4	MILLVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
10	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	NIBLEY SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
19	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
24	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
25	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
34	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	PARIETTE SUBSTATION	DISTRIBUTION-UNATTEN	69.00	24.90	
36	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
38	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
14	1					2
	1					3
12	1					4
2	1					5
19	2					6
13	1					7
3	1					8
7	2					9
6	1					10
6	3					11
5	1					12
6	1					13
6	1					14
7	1					15
20	1					16
5	1					17
14	1					18
25	1					19
2	1					20
25	1					21
22	1					22
25	1					23
45	2					24
14	1					25
24	2					26
6	1					27
22	1					28
2	1					29
20	1					30
14	1					31
48	2					32
4	1					33
5	1					34
4	3					35
35	2					36
50	2					37
16	2					38
6	1					39
55	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	PLEASANT VIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
9	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
11	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
12	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
15	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
16	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
17	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
27	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
29	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
34	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
39	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
40	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2	1					1
14	1					2
22	1					3
25	1					4
14	1					5
30	1					6
2	1					7
4	1					8
60	2					9
4	1					10
15	1					11
2	1					12
1	3					13
14	1					14
12	1					15
2	1					16
45	2					17
45	2					18
5	1					19
22	2					20
11	1					21
40	2					22
20	1					23
5	1					24
4	1					25
30	1					26
24	3					27
	3					28
10	1					29
60	2					30
60	2					31
1	3					32
1	1					33
1	3					34
13	2					35
	1					36
20	1					37
6	1					38
60	2					39
20	1					40

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	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.50	12.50
3	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
16	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	STAIRS SUB	DISTRIBUTION-UNATTEN	12.47	2.40	
18	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
22	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
27	THIRD WEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	THOMPSON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
30	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
31	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
32	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	UNIVERSITY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	12.50
35	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	VEYO HYDRO	DISTRIBUTION-UNATTEN	34.50	2.40	
39	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	1					1
40	1					2
40	2					3
5	1					4
60	2					5
12	1					6
60	2					7
20	2					8
60	2					9
25	1					10
30	1					11
22	1					12
22	2					13
6	1					14
4	1					15
4	1					16
2	1					17
20	1					18
14	1					19
7	1					20
60	2					21
8	1					22
6	1					23
20	1					24
14	1					25
14	1					26
40	2					27
24	2					28
2	1					29
25	1					30
34	2					31
39	2					32
50	2					33
29	2					34
22	1					35
3	1					36
33	2					37
2	3					38
2	1					39
25	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
3	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	
6	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
13	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
19	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
20	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	Total		19709.77	3606.26	117.97
24	Number of Substations-288				
25					
26	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
27	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
28	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
29	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
30	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
31	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
32	DECADE SUB	T/D-UNATTENDED	138.00	12.50	
33	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
34	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
35	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
36	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
37	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
38	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
39	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
40	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
30	1					2
30	1					3
2	3					4
14	1					5
42	2					6
5	1					7
22	1					8
28	1					9
60	2					10
25	1					11
60	3					12
5	1					13
14	1					14
30	1					15
1	1					16
14	1					17
4	1					18
	1					19
6	1					20
20	1					21
2	1					22
5441	400	1				23
						24
						25
1571	5	1				26
135	3					27
30	1					28
205	4					29
40	2					30
289	7					31
60	2					32
60	2					33
8	1					34
72	3					35
114	2					36
97	2					37
164	2					38
22	1					39
340	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
2	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
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	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
9	SPHINX SUB	T/D-UNATTENDED	46.00	12.47	
10	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
11	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
12	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
13	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
14	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
15	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
16	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
17	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
18	Total		5060.00	916.79	906.70
19	Number of Substations-32				
20					
21	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
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	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
26	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
27	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
28	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
29	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
30	BOOKCLIFFS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
31	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
32	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
33	CARBON SUB	TRANSMISSION-UNATTEN	138.00		
34	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
35	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
36	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
37	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
38	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
39	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
40	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
65	2					1
135	3					2
97	2					3
51	7					4
180	3					5
34	4					6
100	2					7
50	2					8
3	1	3				9
600	5					10
358	4					11
1108	6	2				12
130	2					13
159	3					14
30	1					15
30	1					16
20	1					17
6357	89	6				18
						19
						20
783	13	1				21
318	2					22
1513	5	1				23
981	4					24
67	1					25
133	2					26
100	1					27
1813	5					28
100	2					29
6	3	1				30
25	4					31
169	2					32
8	1					33
71	2					34
40	2					35
70	2					36
312	3					37
33	1					38
67	2					39
225	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
2	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
3	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
4	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	
5	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
6	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
8	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
9	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
10	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
11	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
12	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
13	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
14	OLMSTED SUB	TRANSMISSION-UNATTEN	46.00	2.40	
15	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
16	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
17	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
18	RED BUTTE SUB	TRANSMISSION-UNATTEN	230.00	138.00	
19	SAND COVE HYDRO	TRANSMISSION-UNATTEN	34.50	2.40	
20	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
21	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
22	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
23	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
24	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
25	WEBER PLANT/SUB	TRANSMISSION-UNATTEN	46.00	2.30	
26	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
27	Total		8498.50	3177.87	659.38
28	Number of Substations-46				
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	NACHES HYDRO	DISTRIBUTION-UNATTEN	115.00	12.47	
40	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
142	2					1
35	1					2
80	2					3
270	4					4
67	1					5
75	1					6
45	1					7
141	4					8
900	2					9
67	1					10
12	1					11
67	1					12
67	1					13
15	1					14
138	2					15
133	2					16
258	3					17
400	1					18
	1					19
1124	6					20
63	2					21
1017	5					22
100	3	1				23
450	1					24
7	1					25
262	3					26
12769	113	4				27
						28
						29
						30
25	1					31
45	2					32
117	6					33
25	1					34
23	2					35
25	4					36
42	2					37
50	2					38
20	1					39
42	2					40

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	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
2	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	POMEROY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
5	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
12	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
20	Total		2921.00	369.96	107.66
21	Number of Substations-29				
22					
23	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
24	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
25	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
26	Total		368.00	139.94	12.47
27	Number of Substations-3				
28					
29	CONDIT PLANT	TRANSMISSION-ATTENDE	69.00	2.30	
30	MERWIN HYDRO PLANT	TRANSMISSION-ATTENDE	115.00	13.20	
31	YALE PLANT	TRANSMISSION-ATTENDE	115.00	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	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
36	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
37	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
38	Total		1564.00	581.30	7.20
39	Number of Substations-9				
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
45	2					1
50	2					2
28	3					3
9	1					4
40	2					5
20	2					6
51	4					7
45	2					8
25	1					9
45	2					10
29	2					11
50	2					12
6	1					13
25	1					14
10	1					15
45	2					16
25	2					17
22	2					18
45	2					19
1029	59					20
						21
						22
14	1					23
45	2					24
348	5					25
407	8					26
						27
						28
13	6	1				29
183	9	1				30
143	3	1				31
125	1					32
39	9					33
300	2					34
300	2					35
120	2					36
250	1					37
1473	35	3				38
						39
						40

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	WYOMING				
2	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
3	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
4	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
5	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
6	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
8	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
10	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
12	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
13	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
14	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
15	CHAPMAN SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
16	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
17	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
18	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
19	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
20	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
21	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
24	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
25	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
26	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
27	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
29	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
30	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
31	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
32	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
33	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
34	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
35	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
36	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
37	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
38	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
39	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
40	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
						1
25	1					2
13	1					3
2	1					4
25	1					5
7	1					6
8	1					7
150	2					8
73	4					9
25	1					10
2	3					11
2	3					12
2	6	1				13
13	1					14
4	1					15
1	3					16
3	2					17
4	1					18
45	2					19
50	2					20
5	3					21
9	1					22
13	1					23
6	3					24
9	1					25
5	1					26
13	1					27
9	1					28
40	2					29
25	1					30
20	1					31
50	2					32
6	1					33
45	2					34
3	4					35
25	1					36
20	1					37
3	1					38
6	1					39
25	1					40

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	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
2	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
3	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
4	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
5	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
6	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
7	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
8	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
9	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
10	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
11	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
12	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
13	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
14	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
15	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
16	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
17	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
18	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
19	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
20	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
21	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
22	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
23	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
24	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
25	RED BUTTE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
28	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
29	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
31	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
32	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
33	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
34	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
35	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
36	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
37	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
38	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
39	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
40	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	1					1
3	3					2
1	3					3
25	2					4
50	2					5
25	1					6
12	1					7
20	1					8
4	1					9
12	1	1				10
1	3					11
5	1					12
	1					13
7	1					14
1	3					15
3	3					16
30	1					17
5	1					18
7	1					19
17	9	2				20
3	1					21
1	3					22
12	1					23
200	2					24
20	1					25
45	2					26
6	1					27
1	3					28
1	1					29
14	3	1				30
2	6					31
150	2					32
25	1					33
2	3					34
5	1					35
12	1					36
5	1					37
9	1					38
25	2					39
2	3					40

Name of Respondent PacifiCorp	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 06/28/2012	Year/Period of Report End of 2011/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	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
2	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
3	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
4	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
6	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	Total		7493.24	1311.37	38.17
8	Number of Substations-85				
9					
10	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
11	ELK HORN SUB	T/D-UNATTENDED	115.00	12.50	
12	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
13	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
14	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
15	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
16	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
17	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
18	Total		1449.00	208.67	55.30
19	Number of Substations-8				
20					
21	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
22	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
23	JIM BRIDGER UNITS 1-4	TRANSMISSION-ATTENDE	345.00	22.00	
24	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	69.00	138.00
25	WYODAK 230KV SUB	TRANSMISSION-ATTENDE	230.00	69.00	
26	WYODAK PLANT	TRANSMISSION-ATTENDE	230.00	22.00	
27	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
28	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
29	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
30	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
31	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
32	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
33	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
34	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
35	MINERS SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
36	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
37	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
38	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
39	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
40	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	6					1
3	1					2
25	1					3
5	1					4
20	1	1				5
	1					6
1624	157	6				7
						8
						9
20	1					10
25	1					11
50	2					12
45	2	1				13
7	6					14
25	1					15
75	4					16
25	1					17
272	18	1				18
						19
						20
1358	16					21
1084	22					22
1122	2					23
1232	15	1				24
230	3					25
503	3	1				26
53	3					27
517	5					28
67	1					29
75	1					30
196	2					31
15	2					32
20	1					33
90	4					34
58	4	1				35
200	2					36
65	2					37
140	3					38
400	1					39
50	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
2	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
3	Total		4853.00	1722.50	484.20
4	Number of Substations-22				
5					
6	CALIFORNIA				
7	Distribution - 43				
8	T/D - 3				
9	Transmission - 9				
10					
11	IDAHO				
12	Distribution - 65				
13	T/D - 5				
14	Transmission - 18				
15					
16	MONTANA				
17	Transmission - 1				
18					
19	OREGON				
20	Distribution - 182				
21	T/D - 11				
22	Transmission - 42				
23					
24	UTAH				
25	Distribution - 288				
26	T/D - 32				
27	Transmission - 46				
28					
29	WASHINGTON				
30	Distribution - 29				
31	T/D - 3				
32	Transmission - 9				
33					
34	WYOMING				
35	Distribution - 85				
36	T/D - 8				
37	Transmission - 22				
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
175	2					2
7672	97	3				3
						4
						5
						6
324						7
130						8
805						9
						10
						11
723						12
374						13
3504						14
						15
						16
100						17
						18
						19
4541						20
1262						21
6645						22
						23
						24
5441						25
6357						26
12769						27
						28
						29
1029						30
407						31
1473						32
						33
						34
1624						35
272						36
7672						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 - 692				
3	T/D - 62				
4	Transmission - 147				
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					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
						1
13682						2
8802						3
32968						4
						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
						35
						36
						37
						38
						39
						40

Schedule Page: 426.9 Line No.: 26 Column: a

The Dixonville 500kV Substation is jointly owned by the respondent and Bonneville Power Administration ("BPA"). Ownership of the substation is as follows: PacifiCorp 50.0% and BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and BPA 42.0%.

Schedule Page: 426.9 Line No.: 38 Column: a

The Meridian 500kV Substation is jointly owned by the respondent and BPA. Ownership of the substation is as follows: PacifiCorp 50.0% and BPA 50.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 58.0% and BPA 42.0%.

Schedule Page: 426.23 Line No.: 21 Column: a

The Dave Johnston 230kV Substation is jointly owned by the respondent and Black Hills Power. Ownership of the substation is as follows: PacifiCorp 85.0% and Black Hills Power 15.0%. Operation and maintenance costs are shared between the two parties based on a fixed amount derived as a factor of the percentage owned of the original installed substation.

Schedule Page: 426.23 Line No.: 22 Column: a

The Jim Bridger 345kV Substation is jointly owned by the respondent and Idaho Power Company. Ownership of the substation is as follows: 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.: 25 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) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Coal purchases / support services / materials and			
3	supplies	Bridger Coal Company	151, 501, 553	129,809,348
4				
5	Coal mining services	Energy West Mining Company	151	80,202,938
6				
7	Coal purchases	Trapper Mining Inc.	151	14,778,879
8				
9	Administrative support services	Interwest Mining Company	230, 426.5, 557	922,327
10				
11	MEHC affiliate services	MEHC		12,931,780
12		MEC		4,076,895
13		MHC, Inc.	146,426.5,930.2	730,726
14	Charges over cost cap - retained by MEHC	MEHC	146	-62,823
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Information technology & royalties	Bridger Coal Company	146	547,718
22				
23	Financial and administrative support services	Interwest Mining Company	146	752,214
24				
25	Information technology support services	Energy West Mining Company	146	337,787
26				
27				
28	Information technology support and insurance and			
29	risk management services	MEC	146	862,267
30				
31	Legal, resource and construction development			
32	and information technology support services	MEHC	146	319,378
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) ☐ An Original (2) ☒ A Resubmission	06/28/2012	End of 2011/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 Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4	Gas transportation services	Kern River Gas	501,547	3,212,163
5				
6	Relocation services	HomeServices		2,490,590
7				
8	Captive insurance premiums expense	MEHC Insurance Svcs.	924,925	1,536,178
9				
10	Installation of radio equipment	Racom Corporation		981,255
11				
12	Financial transactions related to energy hedging			
13	activity and banking services	Wells Fargo & Company		47,748,748
14				
15	Rail services / right-of-way fees	BNSF Railway Company	151,507,567,589	33,249,919
16				
17	Installation of transmission cable	Marmon Utility LLC		509,231
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Computer hardware and software and computer			
3	systems consulting and maintenance services	International Business Machines	903, 923, 935	315,951
4				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [ ] An Original (2) [X] A Resubmission	06/28/2012	End of 2011/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 Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Rating agency fees	Moody's Investors Service	921	306,137
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 3 Column: d

Non-power goods or services provided by Bridger Coal Company are as follows:

Coal purchases	$ 129,772,184
Support services/materials and supplies	37,164
	$ 129,809,348

Schedule Page: 429 Line No.: 5 Column: d

Under the terms of the coal mining agreement between PacifiCorp and Energy West Mining Company, Energy West Mining Company provides coal mining services to PacifiCorp that are absorbed directly by PacifiCorp.

Schedule Page: 429 Line No.: 9 Column: d

Interwest Mining Company manages PacifiCorp's mining operations and charges management services to Pacific Minerals, Inc., Bridger Coal Company, Energy West Mining Company and Fossil Rock Fuels, LLC. Interest Mining Company also charges PacifiCorp for administrative support services. All costs incurred by Interwest Mining Company are absorbed by PacifiCorp, Pacific Minerals, Inc., Bridger Coal Company, Energy West Mining Company and Fossil Rock Fuels, LLC.

Schedule Page: 429 Line No.: 11 Column: a

The amounts in column (d) were the amounts billed by MEHC and its affiliates to PacifiCorp under the Intercompany Administrative Services Agreement. The fee was capped at $2,250,000 through March 20, 2011. Amounts in excess of the cap have been included on lines 12 and 13 and adjusted out on line 14. A portion of the services provided by MEHC and its affiliates were billed based on allocation factors, which are as follows:

Labor and Assets: An equal weighting of each company's labor and assets expressed as a percentage of the whole ((labor % + assets %) ÷ 2) determines the portion assigned to each company. Labor is 12 months ended through December of the prior year. Assets are total assets at December 31 of the prior year. Five combinations of this allocator are used for allocating services that benefit different companies within the holding company organization.

Processes: This allocator distributes costs of electronic data interchange software and services based on the process count within each platform using such software or services.

Legislative and Regulatory: used to allocate costs incurred by the holding company’s legislative & regulatory groups. The legislative & regulatory groups work on a variety of legislative and regulatory subject matter for a select group of companies within the holding company organization. The legislative and regulatory allocation percentages are based on the legislative & regulatory groups’ estimation of the time and resources spent on these selected companies.

Plant: This allocator distributes costs of managing the corporate insurance function based on assets for each platform.

Schedule Page: 429 Line No.: 11 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “MEHC” ON PAGE 429: Complete name is MidAmerican Energy Holdings Company.

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged for MEHC: 107, 165, 426.4, 426.5, 921, 924, 925, 928, 930.2.

Schedule Page: 429 Line No.: 11 Column: d

Included on this line are “convenience” payments made to vendors by one entity on behalf of, and charged to, other entities within the MEHC group. These convenience payments primarily consist of software license costs. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power.

Convenience payments made by MEHC on behalf of PacifiCorp during the year ended December 31, 2011 were $1,740,504.

Excluded from this line are reimbursements by MEHC for payments made by PacifiCorp to its employees under a long-term incentive plan ("LTIP") maintained by MEHC and annual incentive payments associated with transferred employees. Amounts charged to PacifiCorp for LTIP awards granted to PacifiCorp employees are included in the MEHC affiliate services amount included on page 429, line 11.

The convenience payments, the LTIP reimbursements and the annual incentive payments associated with transferred employees do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 12 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "MEC" ON PAGE 429: Complete name is MidAmerican Energy Company.

Schedule Page: 429 Line No.: 12 Column: c

Accounts charged for MEC: 107, 143, 146, 165, 426.4, 426.5, 921, 928, 929, 930.2.

Schedule Page: 429 Line No.: 12 Column: d

Included on this line are "convenience" payments made to vendors by one entity on behalf of, and charged to, other entities within the MEHC group. These convenience payments primarily consist of software license costs. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power.

Convenience payments made by MEC on behalf of PacifiCorp during the year ended December 31, 2011 were $359,713.

The convenience payments do not constitute "services" as required by this page.

Schedule Page: 429 Line No.: 21 Column: d

Non-power goods or services provided to Bridger Coal Company are as follows:

Information technology	$	420,803
Royalties		126,915
	$	547,718

Schedule Page: 429 Line No.: 23 Column: d

PacifiCorp provides Interwest Mining Company with financial and administrative support and technical services. These costs are charged to Interwest Mining Company and are included in the management services that Interwest Mining Company provides to Pacific Minerals, Inc., Bridger Coal Company, Energy West Mining Company and Fossil Rock Fuels, LLC.

Schedule Page: 429 Line No.: 32 Column: d

A portion of the services provided to MEHC and its affiliates were billed based on the following allocation factors:

Labor and Assets: An equal weighting of each company's labor and assets expressed as a percentage of the whole ((labor % + assets) / 2) determines the portion assigned to each company. Labor is 12 months ended through December of the prior year. Assets are total assets at December 31 of the prior year. Five combinations of this allocator are used for allocating services that benefit different companies within the holding company organization.

Information Technology Infrastructure: – Allocates costs related to shared information technology infrastructure owned by the affiliate to other benefited affiliates based on an aggregation of various measures of usage of such infrastructure including storage capacity utilized, number of servers utilized, server processing times, etc.

Schedule Page: 429.1 Line No.: 4 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “KERN RIVER GAS” ON PAGE 429: Complete name is Kern River Gas Transmission Company.

Schedule Page: 429.1 Line No.: 6 Column: b

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF “HomeServices” ON PAGE 429: Complete name is HomeServices of America, Inc.

Schedule Page: 429.1 Line No.: 6 Column: c

Accounts charged for HomeServices: 501, 506, 514, 535, 539, 548, 549, 553, 556, 557, 560, 561.2, 580, 581, 588, 590, 593, 595, 597, 901, 902, 903, 908, 921, 935 and clearing accounts.

Schedule Page: 429.1 Line No.: 8 Column: a

MEHC Insurance Services Ltd. provided certain insurance coverage under a policy that expired March 20, 2011 and that will not be renewed. Proceeds from claims were $16 million during 2011.

Schedule Page: 429.1 Line No.: 10 Column: c

Accounts charged for Racom Corporation: 500, 506, 511, 513, 514, 545, 588, 593.

Schedule Page: 429.1 Line No.: 13 Column: c

Accounts charged for Wells Fargo & Company: 501, 547, 557, 588, 903, 921, 181, 228.3, 419, 427.

Schedule Page: 429.1 Line No.: 15 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

Rail services	$ 33,223,956
Right-of-way fees	25,963
	$ 33,249,919

Included in the rail services are amounts related to a jointly-owned plant that are paid indirectly to BNSF Railway Company.

Schedule Page: 429.1 Line No.: 17 Column: c

Accounts charged for Marmon Utility LLC: 107, 154, 236, 571, 590, 593.

INDEX

Schedule	Page No.

Schedule	Page No.