ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

May 31, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Service Commission
Heber M. Wells Building, Fourth Floor
P. O. Box 45585
Salt Lake City, Utah 84145

Attention: Gary Widerburg
Commission Secretary

RE: FERC Form No. 1

PacifiCorp (d.b.a. Rocky Mountain Power) resubmits for filing one copy of PacifiCorp's annual FERC Form No. 1 report for the year ended December 31, 2012.

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

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

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

Please direct any informal questions to Dave Taylor, Regulatory Manager, at (801) 220-2923.

Sincerely,

Jeffrey K. Larsen /CA

Jeffrey K. Larsen
Vice President, Regulation & Government Affairs

Enclosure

cc: Cheryl Murray/OCS
Dennis Miller/DPU

THIS FILING IS		
Item 1: [X] 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 2012/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 2012/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) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

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	04 Date Signed *(Mo, Da, Yr)* 04/12/2013

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.

LIST OF SCHEDULES (Electric Utility)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report *(Mo, Da, Yr)*	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 utility company serving 1.8 million retail customers, including residential, commercial, industrial, irrigation and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation and commercial and trading functions are operated under the trade name PacifiCorp Energy.

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

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

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

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

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

CONTROL OVER RESPONDENT

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

Berkshire Hathaway Inc.(a)
MidAmerican Energy Holdings Company ("MEHC") (100%)
PPW Holdings LLC (100% controlled by MEHC)
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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		
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Schedule Page: 103 Line No.: 1 Column: a

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

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

Bridger Coal Company is a coal mining joint venture with Idaho Energy Resources Company, a subsidiary of Idaho Power Company, and is jointly controlled by Pacific Minerals, Inc. and Idaho Energy Resources Company.

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

Effective July 1, 2012, PacifiCorp Environmental Remediation Company ("PERCo"), a wholly owned subsidiary of PacifiCorp, was dissolved, and all assets and liabilities of PERCo were assumed by PacifiCorp.

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

PacifiCorp Investment Management, Inc. ("PIMI") previously performed management services for PERCo. Effective July 1, 2012, PIMI was dissolved.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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, 2012:		
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	244,055
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	300,000
8	President and Chief Executive Officer, PacifiCorp Energy	Micheal G. Dunn	300,000
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Schedule Page: 104 Line No.: 1 Column: a

PacifiCorp sets forth the salary information for its "named executive officers" for the year ended December 31, 2012, 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, 2012 (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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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, 2012:	
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	(SVP, Transmission and System Operations, PacifiCorp)	825 NE Multnomah, Suite 1600, Portland, Oregon 97232
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

Does the respondent have formula rates? [X] 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, Attachment H-1	ER11-3643
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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-kV 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 to adopt a formula transmission rate. In August 2011, the FERC issued an order accepting PacifiCorp's filing and allowing the proposed rates to become effective December 25, 2011, subject to refund. Billing using the new rates commenced in early 2012. The FERC established settlement proceedings to encourage the parties to reach agreement on final rates. In February 2013, agreement with the parties was reached and PacifiCorp filed a settlement agreement with the FERC resolving all issues in the transmission rate case. The settlement agreement is subject to FERC approval and includes modifications to the formula used to determine transmission rates. The FERC approved interim rates for real power loss factors and certain ancillary services effective March 1, 2013 and for a new reactive power service rate to be effective May 1, 2013. The transmission rates will continue to be updated every June according to the formula rate process.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	20120531-5390	05/31/2012	ER11-3643		
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Schedule Page: 1061 Line No.: 1 Column: d

Informational Filing of 2012 Transmission Formula Rate Annual Update

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

PacifiCorp's Volume No. 11 Open Access Transmission Tariff

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

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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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)			
Dubois	03/15/2012	03/15/2047	10.0%
Bloomington	05/29/2012	05/29/2042	10.0%
Downey	06/01/2012	06/01/2042	-
Malad	08/13/2012	08/13/2032	-
Oregon (3)			
Echo	02/13/2012	02/13/2037	3.5%
Stanfield	03/26/2012	03/26/2032	5.5%
Independence	04/16/2012	04/16/2022	7.0%
Medford	06/21/2012	06/21/2022	7.0%
Redmond	07/12/2012	07/12/2017	7.0%
Aumsville	08/13/2012	08/13/2022	7.0%
Mill City	09/12/2012	09/12/2032	5.0%
Utah (2)			
Woodruff	01/18/2012	01/18/2022	6.0%
Randolph	01/18/2012	01/18/2022	5.0%
Vernal	01/26/2012	01/26/2032	6.0%
Laketown	02/16/2012	02/16/2032	-
Garden City	02/27/2012	02/27/2027	-
Alta	03/12/2012	03/12/2017	4.0%
Weber County	03/20/2012	03/20/2022	-
Scofield	12/05/2012	12/05/2037	-
Washington (2)			
Benton County	03/09/2012	02/28/2022	-
Moxee	07/31/2012	07/31/2032	6.0%
Wyoming (4)			
LaBarge	11/09/2012	11/09/2037	1.0%

(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 or associated taxes 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) 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.

None.

ITEM 3.

In February 2012, the Federal Energy Regulatory Commission ("FERC") in Docket No. AC12-7-000 approved the journal entries required by the Uniform System of Accounts ("USofA") for the sale of the Snake Creek hydroelectric generating facility to Heber Light & Power Company. 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, 2011.

In October 2012, PacifiCorp received approval from the FERC in Docket No. EC12-136-000, pursuant to Section 203 of the Federal Power Act, for the acquisition from Brigham City Corporation ("Brigham") of certain 138-kilovolt electric transmission facilities at Brigham's East Substation in Utah and accompanying rights and property. In November 2012, the purchase was recorded in account 102, Electric plant purchased or sold, and PacifiCorp filed for approval with the FERC the journal entries required by the USofA. In March 2013, the FERC in Docket No. AC13-18-000 approved the journal entries for the acquisition. Accordingly, PacifiCorp cleared account 102, Electric plant purchased or sold, and recorded the purchase to the appropriate accounts.

In December 2012, PacifiCorp entered into an agreement for the sale of the St. Anthony hydroelectric generating facility with St. Anthony Hydro LLC, which is subject to regulatory approvals by the FERC, the Idaho Public Utilities Commission ("IPUC") and the Wyoming Public Service Commission. Also in December 2012, PacifiCorp entered into a power purchase agreement with St. Anthony Hydro LLC for all of the net output of the St. Anthony hydroelectric generating facility, which is to become effective after the closing of the sale and approval by the IPUC.

ITEM 4.

In October 2012, PacifiCorp entered into an agreement with RBS Asset Finance, Inc. to lease the 2-megawatt Black Cap Solar generating facility located near Lakeview, Oregon. The lease has a 16-year term from October 2012 to October 2028 and is accounted for as an operating lease. Annual rent payments are $337,383. PacifiCorp also pays for certain executory costs. PacifiCorp received the necessary FERC approval in Docket No. EC12-86-000, pursuant to Section 203 of the Federal Power Act.

ITEM 5.

During the year ended December 31, 2012, 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 no short-term debt outstanding as of December 31, 2012. PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2012. For further discussion, refer to Note 6 of Notes to Financial Statements in this Form No. 1.

Long-term Debt

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 March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.72%, to repay short-term debt and for general corporate purposes.

PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission ("OPUC") and the IPUC 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. 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 $17 million during the year ended December 31, 2012.

As of December 31, 2012, 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, 2012 and expire periodically through November 2013.

For further discussion, refer to Note 6 of Notes to Financial Statements in this Form No. 1.

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, 2012, PacifiCorp estimated it would be able to issue up to $7.8 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 2013, PacifiCorp declared and paid a dividend of $150 million to PPW Holdings LLC, a wholly owned subsidiary of MidAmerican Energy Holdings Company and PacifiCorp’s direct parent company.

In 2012, PacifiCorp declared and paid dividends of $200 million to PPW Holdings LLC.

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)	1.87%	1/26/2012	$ 1,547,483
IBEW 57 Power Supply (UT, ID & WY)	1.85%	1/26/2012	720,115
IBEW 125 (OR, WA)	1.42%	1/26/2012	389,756
IBEW 659 (OR, CA)	1.30%	4/26/2012	449,430
IBEW 57 Combustion Turbine (UT)	1.05%	5/26/2012	24,025
UWUA 197 (OR)	1.20%	5/26/2012	21,075
IBEW 57 Laramie (WY)	0.77%	6/26/2012	4,618
UWUA 127 (WY)	0.53%	9/26/2012	230,184
Total			$ 3,386,686

(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. Refer to Note 13 of Notes to Financial Statements in this Form No. 1 for information regarding legal proceedings, including the USA Power litigation.

ITEM 10.

In July 2012, PacifiCorp Environmental Remediation Company ("PERCo"), a wholly owned subsidiary of PacifiCorp, was dissolved, and all assets and liabilities of PERCo were assumed by PacifiCorp.

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

There have been no officer, director or security holder transactions during the year ended December 31, 2012 other than common and preferred stock dividends declared.

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, 2012 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.

In September 2012, Natalie L. Hocken, director of PacifiCorp, accepted the position of Senior Vice President, Transmission and System Operations of PacifiCorp. Ms. Hocken's previous role was Vice President and General Counsel of Pacific Power. There was no change in Ms. Hocken's role as director of PacifiCorp.

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 accompanying financial statements of PacifiCorp (the "Company"), which comprise the balance sheet — regulatory basis as of December 31, 2012, 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, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements 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 includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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 from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design 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. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2012, 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.

Basis of Accounting

As discussed in Note 2 to the financial statements, 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 basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

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

April 12, 2013

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	23,971,186,312	23,014,228,731
3	Construction Work in Progress (107)	200-201	1,250,513,185	1,203,547,965
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		25,221,699,497	24,217,776,696
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	8,018,360,420	7,666,665,056
6	Net Utility Plant (Enter Total of line 4 less 5)		17,203,339,077	16,551,111,640
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)		17,203,339,077	16,551,111,640
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		16,067,385	15,445,648
19	(Less) Accum. Prov. for Depr. and Amort. (122)		3,461,732	1,917,757
20	Investments in Associated Companies (123)		69,928	69,928
21	Investment in Subsidiary Companies (123.1)	224-225	239,062,484	240,956,268
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		84,847,739	83,950,135
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		19,796,604	6,137,779
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,367,457	4,472,312
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		357,749,865	349,114,313
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		23,522,354	14,846,926
36	Special Deposits (132-134)		139,866	774,146
37	Working Fund (135)		0	1,520
38	Temporary Cash Investments (136)		55,313,879	7,244,794
39	Notes Receivable (141)		102,892	238,519
40	Customer Accounts Receivable (142)		388,339,929	373,179,154
41	Other Accounts Receivable (143)		49,311,318	59,610,652
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,884,148	8,722,762
43	Notes Receivable from Associated Companies (145)		0	13,897,305
44	Accounts Receivable from Assoc. Companies (146)		4,537,480	7,455,752
45	Fuel Stock (151)	227	265,591,187	236,891,214
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	202,524,644	196,564,767
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

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)		45,371,059	113,503,388
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		16,988	26,887
60	Rents Receivable (172)		1,773,869	2,237,540
61	Accrued Utility Revenues (173)		250,650,000	236,917,500
62	Miscellaneous Current and Accrued Assets (174)		481,065	2,574,464
63	Derivative Instrument Assets (175)		9,253,434	15,812,193
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,367,457	4,472,312
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)		1,286,678,359	1,268,581,647
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		34,752,802	33,449,341
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	4,126,549	0
72	Other Regulatory Assets (182.3)	232	1,821,244,610	1,874,535,671
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,377,278	3,115,357
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)		46,898	66,905
78	Miscellaneous Deferred Debits (186)	233	86,782,863	88,864,233
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)		9,502,793	9,676,901
82	Accumulated Deferred Income Taxes (190)	234	648,219,005	639,645,755
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		2,609,052,798	2,649,354,163
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		21,456,820,099	20,818,161,763

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

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.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2012/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	2,979,135,293	2,649,231,266
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	157,299,053	151,915,641
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)	-12,003,821	-9,055,432
16	Total Proprietary Capital (lines 2 through 15)		7,644,054,942	7,311,715,892
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	6,820,029,000	6,171,055,000
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)		102,179	30,127
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		14,074,076	14,072,302
24	Total Long-Term Debt (lines 18 through 23)		6,806,057,103	6,157,012,825
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		48,633,502	53,732,331
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		41,118,850	5,468,000
29	Accumulated Provision for Pensions and Benefits (228.3)		621,638,182	580,877,623
30	Accumulated Miscellaneous Operating Provisions (228.4)		38,367,730	38,369,540
31	Accumulated Provision for Rate Refunds (229)		6,578,797	0
32	Long-Term Portion of Derivative Instrument Liabilities		26,416,841	66,449,954
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		127,418,688	123,312,479
35	Total Other Noncurrent Liabilities (lines 26 through 34)		910,172,590	868,209,927
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	688,527,000
38	Accounts Payable (232)		440,465,394	536,085,457
39	Notes Payable to Associated Companies (233)		11,109,978	0
40	Accounts Payable to Associated Companies (234)		37,303,255	56,292,853
41	Customer Deposits (235)		34,640,410	36,226,196
42	Taxes Accrued (236)	262-263	87,443,808	52,714,616
43	Interest Accrued (237)		114,528,244	110,248,092
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)		17,617,882	17,536,762
48	Miscellaneous Current and Accrued Liabilities (242)		74,650,810	78,951,246
49	Obligations Under Capital Leases-Current (243)		6,482,626	2,156,201
50	Derivative Instrument Liabilities (244)		74,922,884	156,054,864
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		26,416,841	66,449,954
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)		873,260,912	1,668,855,795
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		19,569,969	25,692,158
57	Accumulated Deferred Investment Tax Credits (255)	266-267	34,331,017	38,010,268
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	333,027,535	220,954,063
60	Other Regulatory Liabilities (254)	278	102,737,542	111,258,519
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	208,722,047	164,676,925
63	Accum. Deferred Income Taxes-Other Property (282)		3,796,825,280	3,505,053,651
64	Accum. Deferred Income Taxes-Other (283)		728,061,162	746,721,740
65	Total Deferred Credits (lines 56 through 64)		5,223,274,552	4,812,367,324
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		21,456,820,099	20,818,161,763

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

As of December 31, 2012, Account 236, Taxes accrued, included $55,318,498 of income taxes payable to MidAmerican Energy Holdings Company, PacifiCorp's indirect parent company.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	4,849,485,873	4,553,757,373		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	2,512,486,745	2,304,873,210		
5	Maintenance Expenses (402)	320-323	427,348,788	432,482,383		
6	Depreciation Expense (403)	336-337	571,953,425	544,830,198		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	44,350,044	42,204,359		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	5,523,970	5,523,970		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		507,060	135,566		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		337,452	1,612,926		
13	(Less) Regulatory Credits (407.4)			380,507		
14	Taxes Other Than Income Taxes (408.1)	262-263	160,882,952	151,699,035		
15	Income Taxes - Federal (409.1)	262-263	-106,857,967	-138,818,714		
16	- Other (409.1)	262-263	-785,331	-7,862,714		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	770,193,169	782,981,862		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	419,882,524	424,304,774		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,851,300	-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)		49,887	164,750		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		7,758	14,646		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,964,164,354	3,692,952,492		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		885,321,519	860,804,881		

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
4,849,485,873	4,553,757,373					2
						3
2,512,486,745	2,304,873,210					4
427,348,788	432,482,383					5
571,953,425	544,830,198					6
						7
44,350,044	42,204,359					8
5,523,970	5,523,970					9
507,060	135,566					10
						11
337,452	1,612,926					12
	380,507					13
160,882,952	151,699,035					14
-106,857,967	-138,818,714					15
-785,331	-7,862,714					16
770,193,169	782,981,862					17
419,882,524	424,304,774					18
-1,851,300	-1,874,204					19
						20
						21
49,887	164,750					22
						23
7,758	14,646					24
3,964,164,354	3,692,952,492					25
885,321,519	860,804,881					26

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)		885,321,519	860,804,881		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,143,641	1,731,641		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,064,403	2,055,446		
33	Revenues From Nonutility Operations (417)		651,778	43,686		
34	(Less) Expenses of Nonutility Operations (417.1)		130,325	110,939		
35	Nonoperating Rental Income (418)		-9,703	172,282		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	11,211,230	9,511,469		
37	Interest and Dividend Income (419)		6,422,547	6,005,324		
38	Allowance for Other Funds Used During Construction (419.1)		58,494,261	46,510,051		
39	Miscellaneous Nonoperating Income (421)		602,865	-954,675		
40	Gain on Disposition of Property (421.1)		896,553	508,748		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		78,218,444	61,362,141		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		71,235	37,115		
44	Miscellaneous Amortization (425)		1,292,207	1,290,244		
45	Donations (426.1)		2,491,665	3,009,414		
46	Life Insurance (426.2)		-5,124,160	-3,079,618		
47	Penalties (426.3)		719,036	238,093		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,497,850	2,171,126		
49	Other Deductions (426.5)		129,377,724	8,456,159		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		130,325,557	12,122,533		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	315,476	306,526		
53	Income Taxes-Federal (409.2)	262-263	-1,654,653	-1,538,756		
54	Income Taxes-Other (409.2)	262-263	-224,840	-209,091		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	84,103,300	59,177,256		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	129,629,658	60,347,318		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		1,827,951	2,064,956		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-48,918,326	-4,676,339		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-3,188,787	53,915,947		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		355,713,688	364,553,118		
63	Amort. of Debt Disc. and Expense (428)		3,835,726	3,910,675		
64	Amortization of Loss on Reaquired Debt (428.1)		1,797,595	1,769,844		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,949	2,718		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		-12,665	-15,213		
68	Other Interest Expense (431)		12,226,166	14,342,093		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		28,756,114	24,643,010		
70	Net Interest Charges (Total of lines 62 thru 69)		344,795,447	359,914,789		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		537,337,285	554,806,039		
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)		537,337,285	554,806,039		

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, 2012 and 2011, depreciation expense associated with transportation equipment was $15,898,715 and $14,396,524, 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.: 14 Column: c

Payroll taxes are generally charged to operations and maintenance expense and construction work in progress. During the years ended December 31, 2012 and 2011, payroll taxes were $40,291,150 and $40,298,577, respectively.

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.

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		2,645,655,455	2,652,408,336
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)		526,126,055	545,294,570
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriation of excess earnings at certain hydroelectric generating facilities	215.1	-1,225,845	
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-1,225,845	
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock, various series and rates	238	-2,049,846	(2,049,846)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-2,049,846	(2,049,846)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock	238	-200,000,000	(549,997,605)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-200,000,000	(549,997,605)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		5,827,818	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,974,333,637	2,645,655,455
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)		4,801,656	3,575,811
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		4,801,656	3,575,811
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		2,979,135,293	2,649,231,266
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		151,915,641	142,404,172
50	Equity in Earnings for Year (Credit) (Account 418.1)		11,211,230	9,511,469
51	(Less) Dividends Received (Debit)			
52	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-5,827,818	
53	Balance-End of Year (Total lines 49 thru 52)		157,299,053	151,915,641

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

Outstanding shares of preferred stock as of December 31, 2012 and dividends on preferred stock during the year ended December 31, 2012 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, 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.: 31 Column: c

For information regarding common stock dividends declared, refer to Important Changes During the Quarter/Year, Item 6, in this Form No. 1.

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

For information regarding the dissolution of PacifiCorp Environmental Remediation Company, refer to Important Changes During the Quarter/Year, Item 10, of this Form No.1.

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	537,337,285	554,806,039
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	589,168,608	560,591,577
5	Amortization:	51,502,307	50,140,207
6			
7			
8	Deferred Income Taxes (Net)	304,784,287	357,507,026
9	Investment Tax Credit Adjustment (Net)	-3,679,251	-3,939,160
10	Net (Increase) Decrease in Receivables	-14,624,273	-60,824,263
11	Net (Increase) Decrease in Inventory	-34,659,850	-58,556,736
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	57,856,504	-34,182,597
14	Net (Increase) Decrease in Other Regulatory Assets	17,169,240	-62,618,384
15	Net Increase (Decrease) in Other Regulatory Liabilities	-15,997,931	39,724,553
16	(Less) Allowance for Other Funds Used During Construction	58,494,261	46,510,051
17	(Less) Undistributed Earnings from Subsidiary Companies	5,383,412	9,511,469
18	Amounts Due To/From Affiliates (Net)	110,233,418	313,928,254
19	Derivative Collateral (Net)	68,250,000	3,796,008
20	Other Operating Activities:	25,993,723	21,636,546
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	1,629,456,394	1,625,987,550
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,398,801,462	-1,532,049,103
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	-58,494,261	-46,510,051
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-1,340,307,201	-1,485,539,052
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	739,512	1,788,112
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		-32,230,537
40	Contributions and Advances from Assoc. and Subsidiary Companies	21,169,399	
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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:	-13,553,729	-896,877
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-1,331,952,019	-1,516,878,354
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	748,786,000	399,256,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		652,437,287
67	Other (provide details in footnote):	11,107,806	
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	759,893,806	1,051,693,287
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-101,026,000	-586,686,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-7,826,267	-3,006,612
77	Repayment of Capital Lease Obligations	-1,316,468	-1,364,856
78	Net Decrease in Short-Term Debt (c)	-688,436,607	
79			
80	Dividends on Preferred Stock	-2,049,846	-2,049,846
81	Dividends on Common Stock	-200,000,000	-549,997,605
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-240,761,382	-91,411,632
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	56,742,993	17,697,564
87			
88	Cash and Cash Equivalents at Beginning of Period	22,093,240	4,395,676
89			
90	Cash and Cash Equivalents at End of period	78,836,233	22,093,240

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

Includes depreciation expense associated with transportation equipment and capital lease assets of $17,215,183 and $15,761,379 during the years ended December 31, 2012 and 2011, respectively.

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

	Years Ended December 31, 2012	2011
Amortization of software development & other intangibles	$ 45,642,251	$ 43,494,603
Amortization of electric plant acquisition adjustments	5,523,970	5,523,970
Amortization of regulatory assets	336,086	1,121,634
	$ 51,502,307	$ 50,140,207

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

	Years Ended December 31, 2012	2011
Depreciation and depletion included in cost of fuel	$ 12,461,354	$ 11,712,355
Gain on sale of property	(1,063,591)	(497,935)
Write-off of assets under construction	10,606,163	5,085,213
Unrealized losses on derivative contracts	-	1,116,177
Other	3,989,797	4,220,736
	$ 25,993,723	$ 21,636,546

Schedule Page: 120 Line No.: 22 Column: c

Certain prior period amounts have been reclassified. These reclassifications had no effect on net cash provided by (used in) operating activities.

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.: 53 Column: a

	Years Ended December 31, 2012	2011
Other investments/special funds	$ (369,775)	$ 919,658
Temporary facilities	20,007	23,771
Restricted cash	(13,203,961)	(1,840,306)
	$(13,553,729)	$ (896,877)

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

Intercompany borrowing from subsidiary company, Pacific Minerals, Inc.

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

Long-term debt issuance and other financing costs.

Schedule Page: 120 Line No.: 83 Column: c

Certain prior period amounts have been reclassified. These reclassifications had no effect on net cash provided by (used in) financing activities.

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 retail customers, including residential, commercial, industrial, irrigation 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 services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America ("GAAP"). These notes include 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. Also in accordance with FERC Order No. AC11-132, PacifiCorp does not eliminate intercompany profit on transactions with equity investees as would be required under GAAP. The accounting treatment described above 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 defers 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. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which are recognized in earnings in the periods the corresponding changes in rates occur.

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 that could limit PacifiCorp's ability to recover its costs. 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. 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 money market mutual funds, United States Treasury Bills 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):

	2012	2011
Cash (131)	$ 24	$ 15
Working funds (135)	—	—
Temporary cash investments (136)	55	7
Total cash and cash equivalents	$ 79	$ 22

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, 2012 and 2011, 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 an estimated allowance 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):

	2012	2011
Beginning balance	$ 9	$ 8
Charged to operating costs and expenses, net	14	13
Write-offs, net	(14)	(12)
Ending balance	$ 9	$ 9

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 agreements 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 derivative 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 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 accumulated provision for depreciation or ARO liability is reduced.

Generally when PacifiCorp retires or sells a component of utility plant, it charges the original cost, net of any 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, 2012 and 2011, unbilled revenue was $251 million and $237 million, respectively, and is included in accrued utility revenues 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. As of December 31, 2012 and 2011, these amounts were recognized as regulatory assets of $456 million and $444 million, respectively, and regulatory liabilities of $21 million and $22 million, 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. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense in the period of enactment. Valuation allowances are established for certain deferred income tax assets where realization is not likely.

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 income 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 income 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 is more likely than not of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income 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. In January 2013, the FASB issued ASU No. 2013-01, which also amends FASB ASC Topic 210 to clarify that the scope of ASU No. 2011-11 only applies to derivative instruments, repurchase agreements, reverse purchase agreements and securities borrowing and securities lending transactions that are either being offset or are subject to an enforceable master netting arrangement or similar agreement. ASU No. 2013-01 is also 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 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 adopted ASU No. 2011-04 on January 1, 2012. 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 each of the years ended December 31, 2012 and 2011.

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, 2012 and 2011 and accumulated provision for depreciation, amortization and depletion of $113 million and $107 million as of December 31, 2012 and 2011, 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, 2012 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,087	$ 519	$ 33
Hunter No. 1	94	391	144	19
Hunter No. 2	60	301	81	—
Wyodak	80	450	155	2
Colstrip Nos. 3 and 4	10	223	122	1
Hermiston	50	172	58	1
Craig Nos. 1 and 2	19	177	95	4
Hayden No. 1	25	55	25	1
Hayden No. 2	13	32	16	—
Foote Creek	79	37	20	—
Transmission and distribution facilities	Various	325	65	1
Total		$ 3,250	$ 1,300	$ 62

(5) Regulatory Matters

PacifiCorp had regulatory assets not earning a return on investment of $1.618 billion and $1.662 billion as of December 31, 2012 and 2011, respectively.

(6) Short-term Debt and Other Financing Agreements

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

2012:	
Available revolving credit facilities	$ 1,230
Less:	
Short-term debt	—
Letters of credit supporting tax-exempt bond obligations and collateral requirements of commodity contracts	(602)
Net revolving credit facilities available	$ 628
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

In June 2012, PacifiCorp replaced its existing $635 million unsecured revolving credit facility with a $600 million unsecured revolving credit facility expiring in June 2017. This facility is for general corporate purposes including supporting PacifiCorp's commercial paper program and provides for the issuance of letters of credit. Additionally, as of December 31, 2012, PacifiCorp had an unsecured revolving credit facility, which had $720 million available until July 2012 and had $630 million available until July 2013, which supported PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. During March 2013, PacifiCorp replaced the $630 million unsecured revolving credit facility with a $600 million unsecured credit facility expiring in March 2018. These credit facilities have a variable interest rate based on the London Interbank Offered Rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. As of December 31, 2011, the weighted-average interest rate on commercial paper borrowings outstanding was 0.51%. The credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter for each of the two $600 million credit facilities or at any time for the $630 million credit facility. As of December 31, 2012, PacifiCorp was in compliance with the covenants of its revolving credit facilities.

As of December 31, 2012 and 2011, PacifiCorp had $602 million and $601 million, respectively, of letters of credit issued under committed arrangements, of which $602 million and $304 million, respectively, were issued under the revolving credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and certain collateral requirements of commodity contracts, and were fully available as of December 31, 2012 and 2011. Certain of these letters of credit were replaced during March 2013 and all letters of credit currently expire periodically from November 2013 through March 2015.

As of December 31, 2012, PacifiCorp had approximately $14 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, 2012 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.

(7) 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 through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 2022 and $300 million of its 4.10% First Mortgage Bonds due February 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. In March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.72%, to 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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $23 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2012.

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 $55 million and $56 million as of December 31, 2012 and 2011, respectively, were included in net utility plant in the Comparative Balance Sheet.

As of December 31, 2012, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2013 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2013	$ 261	$ 12	$ 273
2014	253	8	261
2015	122	7	129
2016	57	7	64
2017	52	11	63
Thereafter	6,075	70	6,145
Total	6,820	115	6,935
Unamortized discount	(14)	—	(14)
Amounts representing interest	—	(60)	(60)
Total	$ 6,806	$ 55	$ 6,861

(8) Income Taxes

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

	2012	2011
Current:		
Federal	$ (108)	$ (140)
State	(1)	(8)
Total	(109)	(148)
Deferred:		
Federal	273	320
State	32	37
Total	305	357
Investment tax credits	(4)	(4)
Total income tax expense	$ 192	$ 205

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:

	2012	2011
Federal statutory income tax rate	35%	35%
State income taxes, net of federal income tax benefit	3	2
Federal income tax credits(1)	(9)	(10)
Effects of ratemaking	(1)	—
Other	(2)	—
Effective income tax rate	26%	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):

	2012	2011
Deferred income tax assets:		
Employee benefits	$ 217	$ 210
State carryforwards	69	62
Unamortized contract values	63	72
Derivative contracts	46	100
Regulatory liabilities	40	43
Other	213	153
	648	640
Deferred income tax liabilities:		
Property, plant and equipment	(4,005)	(3,670)
Regulatory assets	(696)	(715)
Other	(32)	(32)
	(4,733)	(4,417)
Net deferred income tax liability	$ (4,085)	$ (3,777)

As of December 31, 2012, PacifiCorp has available $69 million of state carryforwards, principally for net operating losses, which expire at various intervals between 2013 and 2032.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the March 31, 2006 tax year. State jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

As of December 31, 2012 and 2011, net unrecognized tax benefits totaled $47 million and $64 million, respectively, which included $- million and $8 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.

(9) 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"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary contributes to a multiemployer pension plan 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 all non-union employees hired after January 1, 2008. 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 limited 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 Amendment

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.

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	
	2012	2011	2012	2011
Service cost	$ 7	$ 10	$ 7	$ 7
Interest cost	61	63	28	31
Expected return on plan assets	(74)	(75)	(30)	(30)
Net amortization	34	20	4	18
Net periodic benefit cost	$ 28	$ 18	$ 9	$ 26

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	
	2012	2011	2012	2011
Plan assets at fair value, beginning of year	$ 931	$ 960	$ 384	$ 389
Employer contributions	49	71	9	28
Participant contributions	—	—	7	9
Actual return on plan assets	120	(13)	52	(4)
Benefits paid	(88)	(87)	(28)	(38)
Plan assets at fair value, end of year	$ 1,012	$ 931	$ 424	$ 384

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

	Pension		Other Postretirement	
	2012	2011	2012	2011
Benefit obligation, beginning of year	$ 1,291	$ 1,236	$ 575	$ 581
Service cost	7	10	7	7
Interest cost	61	63	28	31
Participant contributions	—	—	7	9
Plan amendments	—	(4)	—	(54)
Actuarial loss	120	73	43	36
Benefits paid, net of Medicare subsidy	(88)	(87)	(28)	(35)
Benefit obligation, end of year	$ 1,391	$ 1,291	$ 632	$ 575
Accumulated benefit obligation, end of year	$ 1,390	$ 1,289		

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	
	2012	2011	2012	2011
Plan assets at fair value, end of year	$ 1,012	$ 931	$ 424	$ 384
Less - Benefit obligation, end of year	1,391	1,291	632	575
Funded status	$ (379)	$ (360)	$ (208)	$ (191)

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 $44 million and $41 million as of December 31, 2012 and 2011, respectively. These assets are not included in the plan assets in the above table, but are reflected in other investments on the Comparative Balance Sheet.

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	
	2012	2011	2012	2011
Net loss	$ 660	$ 630	$ 214	$ 206
Prior service credit	(37)	(45)	(40)	(46)
Regulatory deferrals	(5)	(7)	3	3
Total	$ 618	$ 578	$ 177	$ 163

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2012 and 2011 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net loss arising during the year	68	6	74
Net amortization	(33)	(1)	(34)
Total	35	5	40
Balance, December 31, 2012	$ 599	$ 19	$ 618

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2010	$ 165
Net loss arising during the year	70
Prior service credit arising during the year	(46)
Reduction in net transition obligation	(8)
Net amortization	(18)
Total	(2)
Balance, December 31, 2011	163
Net loss arising during the year	18
Net amortization	(4)
Total	14
Balance, December 31, 2012	$ 177

The net loss, prior service credit and regulatory deferrals that will be amortized in 2013 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 57	$ (8)	$ (1)	$ 48
Other postretirement	15	(7)	1	9
Total	$ 72	$ (15)	$ —	$ 57

Plan Assumptions

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

	Pension		Other Postretirement	
	2012	**2011**	**2012**	**2011**
Benefit obligations as of December 31:				
Discount rate	4.05%	4.90%	4.10%	4.95%
Rate of compensation increase	3.00	3.50	N/A	N/A
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.90%	5.35%	4.95%	5.45%
Expected return on plan assets	7.50	7.50	7.50	7.50
Rate of compensation increase	3.50	3.50	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.

	2012	**2011**
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.50%
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	2018	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	48	(38)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $64 million and $13 million, respectively, during 2013. 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 2013 through 2017 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments		
		Other Postretirement	
	Pension	Gross	Medicare Subsidy
2013	$ 100	$ 36	$ —
2014	102	37	—
2015	104	37	—
2016	106	39	(1)
2017	103	41	(1)
2018 - 2022	482	207	(4)

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 equity and debt 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 long-term 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, 2012:

	Pension(1)	Other Postretirement(1)
	%	%
Equity securities(2)	53 - 57	61 - 65
Debt securities(2)	33 - 37	33 - 37
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 plan are held in 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 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, 2012				
Cash equivalents	$ 1	$ 8	$ —	$ 9
Debt securities:				
United States government obligations	48	—	—	48
International government obligations	—	67	—	67
Corporate obligations	—	64	—	64
Municipal obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	34	—	34
Equity securities:				
United States companies	383	—	—	383
International companies	7	—	—	7
Investment funds(2)	112	185	—	297
Limited partnership interests(3)	—	—	96	96
Total	$ 551	$ 365	$ 96	$ 1,012
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

(1) Refer to Note 12 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 60% and 40%, respectively, for 2012 and 59% and 41%, respectively, for 2011. Additionally, these funds are invested in United States and international securities of approximately 42% and 58%, respectively, for 2012 and 49% and 51%, respectively, for 2011.

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

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
As of December 31, 2012				
Cash and cash equivalents	$ 4	$ —	$ —	$ 4
Debt securities:				
United States government obligations	4	—	—	4
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	137	—	—	137
International companies	3	—	—	3
Investment funds(2)	152	103	—	255
Limited partnership interests(3)	—	—	7	7
Total	$ 300	$ 117	$ 7	$ 424
As of 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

(1) Refer to Note 12 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 2012 and 2011. Additionally, these funds are invested in United States and international securities of approximately 66% and 34%, respectively, for 2012 and 69% and 31%, respectively, for 2011.

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

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. Most investments in limited partnership interests are valued at estimated fair value based on the Retirement Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and estimated 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. One of the limited partnerships is valued at the unit price calculated by the general partner primarily based on independent appraised values of the underlying property holdings.

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):

	Limited Partnership Interests	
	Pension	Other Postretirement
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
Actual return on plan assets still held at December 31, 2012	7	—
Purchases, sales, distributions and settlements	18	1
Balance, December 31, 2012	$ 96	$ 7

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and a subsidiary contributes to the United Mine Workers of America 1974 Pension Plan ("UMWA Pension Plan") (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and was formed with the ability for other employers to participate in the plan.

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 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. 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. Furthermore, to the extent a participating employer defaults on its obligation to the plan, the remaining employers may be allocated a share of the defaulting employer's obligation for unfunded vested benefits. Under the terms of the UMWA Pension Plan, in the event the mining operations cease, PacifiCorp's subsidiary may be subject to a withdrawal liability.

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

Plan name	Employer Identification Number	PPA zone status or plan funded status percentage for plan years beginning July 1,(1) 2012	2011	Funding improvement plan	Surcharge imposed under PPA	Contributions(2) 2012	2011	Year contributions to plan exceeded more than 5% of total contributions(3)
UMWA Pension Plan	52-1050282	Orange	Orange	Implemented	None	$ 3	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	None	None	$ 12	$ 12	2011, 2010

(1) Among other factors, multiemployer plans in the red zone are generally less than 65 percent funded; multiemployer plans in the yellow zone either (a) are at least 65 percent but less than 80 percent funded or (b) have an accumulated funding deficiency for such plan year, or are projected to have such an accumulated funding deficiency for any of the six succeeding plan years; multiemployer plans in the orange zone meet both of the criteria for yellow zone; and multiemployer plans in the green zone are at least 80 percent funded. Multiemployer plans in the red, yellow, orange or green zones are also referred to as being in critical, endangered, seriously endangered or neither endangered nor critical status, respectively.

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

(3) For the UMWA Pension Plan, information is for plan year beginning July 1, 2010. Information for the plan years beginning July 1, 2012 and 2011 is not available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2011 and 2010. Information for the plan year beginning July 1, 2012 is not yet available.

Although the collective bargaining agreements governing the UMWA Pension Plan and the Local 57 Trust Fund expired in January 2013, operations will continue under the provisions of the agreements until such time that new agreements are reached or the existing agreements are terminated.

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 $36 million and $38 million for the years ended December 31, 2012 and 2011, respectively.

(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 in accordance with accepted regulatory practices. These accruals totaled $810 million and $782 million as of December 31, 2012 and 2011, respectively.

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

	2012	2011
Beginning balance	$ 123	$ 105
Change in estimated costs[1]	17	2
Additions	4	29
Retirements	(22)	(19)
Accretion	5	6
Ending balance	$ 127	$ 123

(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) 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 12 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):

	Current Assets	Long-term Assets	Current Liabilities	Long-term Liabilities	Total
As of December 31, 2012					
Not designated as hedging contracts[1]:					
Commodity assets	$ 10	$ 3	$ 18	$ 1	$ 32
Commodity liabilities	(2)	(2)	(122)	(27)	(153)
Total	8	1	(104)	(26)	(121)
Total derivatives	8	1	(104)	(26)	(121)
Cash collateral receivable	—	—	55	—	55
Total derivatives - net basis	$ 8	$ 1	$ (49)	$ (26)	$ (66)
As of December 31, 2011					
Not designated as hedging contracts[1]:					
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2012 and 2011, a regulatory asset of $121 million and $264 million, respectively, was recorded related to the net derivative liability of $121 million and $264 million, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2012	2011
Beginning balance	$ 264	$ 487
Changes in fair value recognized in regulatory assets	45	(2)
Net losses reclassified to unamortized contract value regulatory asset	—	(168)
Net gains reclassified to operating revenue	38	18
Net losses reclassified to energy costs	(226)	(71)
Ending balance	$ 121	$ 264

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	2012	2011
Electricity sales	Megawatt hours	(1)	(2)
Natural gas purchases	Decatherms	74	96
Fuel oil purchases	Gallons	16	17

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, 2012, 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 $153 million and $378 million as of December 31, 2012 and 2011, respectively, for which PacifiCorp had posted collateral of $56 million and $125 million, respectively, in the form of cash deposits and letters of credit. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2012 and 2011, PacifiCorp would have been required to post $73 million and $155 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.

(12) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, other 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, 2012					
Assets:					
Commodity derivatives	$ —	$ 32	$ —	$ (23)	$ 9
Money market mutual funds(2)	73	—	—	—	73
	$ 73	$ 32	$ —	$ (23)	$ 82
Liabilities - Commodity derivatives	$ —	$ (153)	$ —	$ 78	$ (75)
As of December 31, 2011					
Assets:					
Commodity derivatives	$ —	$ 114	$ 1	$ (100)	$ 15
Money market mutual funds(2)	9	—	—	—	9
	$ 9	$ 114	$ 1	$ (100)	$ 24
Liabilities - Commodity derivatives	$ —	$ (379)	$ —	$ 223	$ (156)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $55 million and $123 million as of December 31, 2012 and 2011, 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 11 for further discussion regarding PacifiCorp's risk management and hedging activities.

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):

	2012	2011
Beginning balance	$ 1	$ (345)
Changes in fair value recognized in regulatory assets	1	132
Contracts designated as normal purchases or normal sales	—	168
Settlements	(2)	46
Ending balance	$ —	$ 1

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 were reclassified from derivative contracts to other assets and liabilities. The frozen liability and associated regulatory asset are being 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 is a Level 2 fair value measurement and 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):

	2012		2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 6,806	$ 8,350	$ 6,157	$ 7,804

(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. 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.

USA Power

In October 2005, prior to MEHC's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. 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. In May 2010, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration, which led to a trial that began in April 2012. In May 2012, the jury reached a verdict in favor of the Plaintiff on its claims. The jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. In May 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 all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial (collectively, "PacifiCorp's post-trial motions"). The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for prejudgment interest. In January and February 2013, PacifiCorp filed its responses to the Plaintiff's post-trial motions for exemplary damages, attorneys' fees and prejudgment interest. A judgment was rendered in April 2013, where the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked rather than the Plaintiff's request for an amount equal to 40% of all amounts ultimately awarded. PacifiCorp strongly disagrees with the jury's verdict and plans to vigorously pursue all appellate measures. As of December 31, 2012, PacifiCorp accrued $113 million, plus estimated obligations for the Plaintiff's motions, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the financial results. Any payment of damages will be at the end of the appeal process, which could take as long as several years.

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. PacifiCorp engaged in settlement discussions with certain of the parties to the proceeding, which have been approved by the FERC. The outcome of such settlements did not have a material impact on PacifiCorp's 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 Klamath hydroelectric system is currently operating under annual licenses with the FERC. 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 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 with the FERC. In November 2011, bills were introduced in both chambers of the 112th 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. These bills are pending re-introduction into the 113th United States Congress.

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 into trust accounts maintained by the OPUC. PacifiCorp has begun collection of surcharges from California customers for their share of dam removal costs, as approved by the California Public Utilities Commission ("CPUC"), and is depositing the proceeds into trust accounts maintained by the CPUC. PacifiCorp is authorized to collect the surcharges through 2019.

As of December 31, 2012, PacifiCorp's assets included $115 million of costs associated with the Klamath hydroelectric system's 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 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 Idaho and Washington general rate cases, which were settled in January 2012 and March 2012, respectively, without a decision on this matter. As part of the September 2012 Utah general rate case order, the Utah Public Service Commission approved recovery of Utah's share of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs through December 31, 2022.

Hydroelectric Commitments

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 $184 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, 2012 are as follows (in millions):

	2013	2014	2015	2016	2017	2018 and Thereafter	Total
Contract type:							
Purchased electricity contracts	$ 178	$ 112	$ 113	$ 94	$ 69	$ 450	$ 1,016
Fuel contracts	666	646	525	411	389	1,978	4,615
Construction commitments	408	158	25	13	10	60	674
Transmission	105	97	75	68	61	671	1,077
Operating leases and easements	6	5	4	3	2	44	64
Maintenance, service and other contracts	31	22	12	8	12	71	156
Total commitments	$ 1,394	$ 1,040	$ 754	$ 597	$ 543	$ 3,274	$ 7,602

Purchased Electricity Contracts

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. Rent expense related to those power purchase agreements that meet the definition of an operating lease totaled $19 million for 2012 and $28 million for 2011.

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 2012 and 2011 energy sources.

Fuel Contracts

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, 2012, PacifiCorp had the following 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 mid-2013 and (b) another segment of the Energy Gateway Transmission Expansion Program that is expected to be placed in service within the next several years, depending on siting, permitting and construction schedules.

- PacifiCorp is constructing the 645-megawatt 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 certain operating facilities, office space, land and equipment 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 $14 million for 2012 and $18 million for 2011.

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, 2012 and 2011.

(15) Common Shareholder's Equity

In January 2013, PacifiCorp declared and paid a dividend of $150 million to PPW Holdings LLC, a direct wholly owned subsidiary of MEHC and PacifiCorp's direct parent company.

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 equity below specified percentages of defined capitalization. As of December 31, 2012, 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 equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. 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, 2012, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53.7%, and PacifiCorp would have been permitted to dividend $2.5 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, 2012, 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 Note 6.

(16) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2012	2011
Interest paid, net of amounts capitalized	$ 330	$ 358
Income taxes received, net	$ 209	$ 425
Supplemental disclosure of non-cash investing and financing activities:		
Accounts payable related to utility plant additions	$ 167	$ 230

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				(6,961,899)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				215,312
3	Preceding Quarter/Year to Date Changes in Fair Value				(2,308,845)
4	Total (lines 2 and 3)				(2,093,533)
5	Balance of Account 219 at End of Preceding Quarter/Year				(9,055,432)
6	Balance of Account 219 at Beginning of Current Year				(9,055,432)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				317,072
8	Current Quarter/Year to Date Changes in Fair Value				(3,265,461)
9	Total (lines 7 and 8)				(2,948,389)
10	Balance of Account 219 at End of Current Quarter/Year				(12,003,821)

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			(6,961,899)		
2		193,628	408,940		
3		(193,628)	(2,502,473)		
4			(2,093,533)	554,806,039	552,712,506
5			(9,055,432)		
6			(9,055,432)		
7			317,072		
8			(3,265,461)		
9			(2,948,389)	537,337,285	534,388,896
10			(12,003,821)		

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

Other Cash Flow Hedges relate to commodity derivatives.

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

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	23,667,394,313	23,667,394,313
4	Property Under Capital Leases	55,116,128	55,116,128
5	Plant Purchased or Sold	124,000	124,000
6	Completed Construction not Classified	66,718,983	66,718,983
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	23,789,353,424	23,789,353,424
9	Leased to Others		
10	Held for Future Use	22,657,380	22,657,380
11	Construction Work in Progress	1,250,513,185	1,250,513,185
12	Acquisition Adjustments	159,175,508	159,175,508
13	Total Utility Plant (8 thru 12)	25,221,699,497	25,221,699,497
14	Accum Prov for Depr, Amort, & Depl	8,018,360,420	8,018,360,420
15	Net Utility Plant (13 less 14)	17,203,339,077	17,203,339,077
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	7,404,667,421	7,404,667,421
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	500,799,794	500,799,794
22	Total In Service (18 thru 21)	7,905,467,215	7,905,467,215
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	112,893,205	112,893,205
33	Total Accum Prov (equals 14) (22,26,30,31,32)	8,018,360,420	8,018,360,420

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
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					31
					32
					33

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	206,078,420	236,195
4	(303) Miscellaneous Intangible Plant	647,383,700	27,221,314
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	853,462,120	27,457,509
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	93,007,584	156,573
9	(311) Structures and Improvements	941,704,583	11,249,443
10	(312) Boiler Plant Equipment	3,879,646,048	376,881,774
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	952,686,011	40,722,959
13	(315) Accessory Electric Equipment	428,911,328	4,056,478
14	(316) Misc. Power Plant Equipment	33,573,404	959,463
15	(317) Asset Retirement Costs for Steam Production	43,030,473	10,781,638
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	6,372,559,431	444,808,328
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	26,050,773	5,473,318
28	(331) Structures and Improvements	141,357,005	42,078,860
29	(332) Reservoirs, Dams, and Waterways	356,202,634	102,698,860
30	(333) Water Wheels, Turbines, and Generators	119,250,199	442,910
31	(334) Accessory Electric Equipment	66,402,841	9,249,705
32	(335) Misc. Power PLant Equipment	2,352,057	19,494
33	(336) Roads, Railroads, and Bridges	16,845,455	853,224
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	728,460,964	160,816,371
36	D. Other Production Plant		
37	(340) Land and Land Rights	28,912,692	74,986
38	(341) Structures and Improvements	164,070,313	344,225
39	(342) Fuel Holders, Products, and Accessories	10,708,652	199,161
40	(343) Prime Movers	2,497,158,539	29,049,193
41	(344) Generators	352,333,243	1,775,103
42	(345) Accessory Electric Equipment	249,243,221	656,562
43	(346) Misc. Power Plant Equipment	12,396,937	139,098
44	(347) Asset Retirement Costs for Other Production	5,109,797	3,962,218
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,319,933,394	36,200,546
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	10,420,953,789	641,825,245

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
			206,314,615		3
27,164,263		664,060	648,104,811		4
27,164,263		664,060	854,419,426		5
					6
					7
			93,164,157		8
1,685,524		53,319,616	1,004,588,118		9
66,603,981		-97,940,222	4,091,983,619		10
					11
26,428,111		-14,585	966,966,274		12
1,209,009		43,747,695	475,506,492		13
165,386			34,367,481		14
	-113,569		53,698,542		15
96,092,011	-113,569	-887,496	6,720,274,683		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
3,143		-131,184	31,389,764		27
851,994		-936,864	181,647,007		28
5,231,961		-430,858	453,238,675		29
177,797		636,059	120,151,371		30
253,458		-641,287	74,757,801		31
14,438		1,238	2,358,351		32
13,966		-49,086	17,635,627		33
					34
6,546,757		-1,551,982	881,178,596		35
					36
18,077		126,970	29,096,571		37
27,195		-77	164,387,266		38
106,690			10,801,123		39
13,796,578		-464	2,512,410,690		40
718,518		264	353,390,092		41
276,619		-63,913	249,559,251		42
59,906		53	12,476,182		43
			9,072,015		44
15,003,583		62,833	3,341,193,190		45
117,642,351	-113,569	-2,376,645	10,942,646,469		46

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	189,547,944	8,885,370
49	(352) Structures and Improvements	147,332,899	3,547,184
50	(353) Station Equipment	1,613,127,173	161,767,856
51	(354) Towers and Fixtures	984,782,939	7,293,362
52	(355) Poles and Fixtures	646,562,331	42,144,868
53	(356) Overhead Conductors and Devices	896,743,379	24,195,286
54	(357) Underground Conduit	3,259,618	56,007
55	(358) Underground Conductors and Devices	7,475,095	14,084
56	(359) Roads and Trails	11,586,681	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,500,418,059	247,904,017
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	55,701,416	4,172,303
61	(361) Structures and Improvements	83,116,060	1,773,758
62	(362) Station Equipment	847,652,682	46,485,145
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	987,694,151	35,859,072
65	(365) Overhead Conductors and Devices	665,402,916	17,097,660
66	(366) Underground Conduit	312,231,842	11,904,186
67	(367) Underground Conductors and Devices	738,536,581	23,037,978
68	(368) Line Transformers	1,135,844,771	38,119,095
69	(369) Services	604,680,445	25,185,585
70	(370) Meters	175,522,842	4,187,547
71	(371) Installations on Customer Premises	8,787,057	133,085
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	61,094,426	1,366,327
74	(374) Asset Retirement Costs for Distribution Plant	2,635,225	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	5,678,900,414	209,321,741
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	19,537,440	58,406
87	(390) Structures and Improvements	248,411,354	4,353,138
88	(391) Office Furniture and Equipment	80,884,267	9,086,454
89	(392) Transportation Equipment	104,525,735	2,136,448
90	(393) Stores Equipment	14,124,139	718,756
91	(394) Tools, Shop and Garage Equipment	63,134,822	1,497,809
92	(395) Laboratory Equipment	38,028,514	687,313
93	(396) Power Operated Equipment	150,984,026	13,001,121
94	(397) Communication Equipment	298,389,515	46,031,518
95	(398) Miscellaneous Equipment	7,308,855	306,015
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,025,328,667	77,876,978
97	(399) Other Tangible Property	291,200,775	9,443,628
98	(399.1) Asset Retirement Costs for General Plant	39,748	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,316,569,190	87,320,606
100	TOTAL (Accounts 101 and 106)	22,770,303,572	1,213,829,118
101	(102) Electric Plant Purchased (See Instr. 8)		124,000
102	(Less) (102) Electric Plant Sold (See Instr. 8)	779,590	
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	22,769,523,982	1,213,953,118

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
145,643		-69,602	198,218,069		48
421,608		20,490,710	170,949,185		49
15,944,257		-23,622,335	1,735,328,437		50
67,503			992,008,798		51
2,492,429			686,214,770		52
1,133,107			919,805,558		53
2,782			3,312,843		54
			7,489,179		55
			11,586,681		56
					57
20,207,329		-3,201,227	4,724,913,520		58
					59
2,587		-246,105	59,625,027		60
136,381		4,390,800	89,144,237		61
5,765,886		-3,949,798	884,422,143		62
					63
7,947,693			1,015,605,530		64
2,590,265			679,910,311		65
1,429,261			322,706,767		66
2,523,994			759,050,565		67
8,848,090			1,165,115,776		68
879,558			628,986,472		69
3,023,274			176,687,115		70
92,229			8,827,913		71
					72
2,016,969			60,443,784		73
	-175,777		2,459,448		74
35,256,187	-175,777	194,897	5,852,985,088		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-117,240	19,478,606		86
12,142,572		-13,139,214	227,482,706		87
12,300,204		12,234,166	89,904,683		88
3,489,943		55,057	103,227,297		89
323,662		49,303	14,568,536		90
1,285,264		-459,744	62,887,623		91
1,843,389		180,897	37,053,335		92
8,791,062			155,194,085		93
2,382,369		2,708,373	344,747,037		94
100,787		414,955	7,929,038		95
42,659,252		1,926,553	1,062,472,946		96
3,651,427	-303,740	-53,137	296,636,099		97
			39,748		98
46,310,679	-303,740	1,873,416	1,359,148,793		99
246,580,809	-593,086	-2,845,499	23,734,113,296		100
			124,000		101
		-779,590			102
					103
246,580,809	-593,086	-2,065,909	23,734,237,296		104

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

Account	Description (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	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	40,275,390	156,436	78,228	-	(8,922)	40,344,676
39941	Surface-Plant Equipment	12,735,825	1,216,339	398,134	-	-	13,554,030
39944	Surface-Electric Power Facil	3,424,575	-	-	-	-	3,424,575
39945	Underground-Coal Mine Equip	73,172,343	3,211,528	3,019,969	-	-	73,363,902
39946	Longwall Shields	24,481,714	4,974	-	-	-	24,486,688
39947	Longwall Equipment	7,865,108	1,250,804	-	-	-	9,115,912
39948	Mainline Extension	18,899,199	1,069,011	-	-	-	19,968,210
39949	Section Extension	6,139,057	1,154,829	-	-	-	7,293,886
39951	Vehicles	1,237,982	41,884	-	-	(44,215)	1,235,651
39952	Heavy Construction Equip	6,158,245	-	-	-	-	6,158,245
39960	Miscellaneous General Equip	2,331,379	337,401	148,802	-	-	2,519,978
39961	Computers-Mainframe	392,406	12,461	6,294	-	-	398,573
39970	Mine Development and Road Ext	38,414,877	443,161	-	-	-	38,858,038
39915	Coal Mine ARO	487,112	544,800	-	(303,740)	-	728,172
		$291,200,775	$9,443,628	$3,651,427	$(303,740)	$(53,137)	$296,636,099

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: e

See footnote line 97, column b.

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

See footnote line 97, column b.

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

See footnote line 97, column b.

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

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

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

Refer to 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	2023	6,763,094
6	Twelve Mile Wind Plant	2007	2021	2,160,207
7	Jumbers Point Substation	2008	2020	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	2016	396,020
11	Bend Service Center	2010	2021	3,507,838
12	Legacy Substation	2010	2025	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	Lassen Substation	2012	2019	683,318
18	Old Mill Substation	2012	2020	1,837,942
19				
20	Miscellaneous, each under $250,000			848,022
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			22,657,380

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 2023, subject to environmental and economic reviews and the timing of completion of the Energy Gateway Transmission 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 Transmission 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.: 20 Column: c

Various dates and plans.

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	IT-Mobility Upgrade / Click Replacement	2,056,236
3	Call Center Automated Call Distribution Replacement Project	1,294,424
4		
5	Production:	
6	Lake Side 2 Development	434,091,679
7	Lewis River System Relicensing Implementation	47,808,833
8	Jim Bridger U2 Turbine Upgrade HP/IP/LP	21,741,404
9	Blundell Proofing Well Integration	18,578,016
10	Hunter U1 Clean Air - Particulate Matter Emissions	18,329,457
11	North Umpqua Coating Projects	2,744,421
12	Merwin Spillway Tainter Gate Rehab	2,709,148
13	Currant Creek 2 Build	2,078,208
14	Blundell U1 Turbine Exhaust Casing	1,915,430
15	Hayden U1 Selective Catalytic Reducer Installation	1,321,147
16	Swift 1 Trunnion Improvements	1,151,720
17	Jim Bridger U2 Replace Cooling Tower	1,129,037
18		
19	Transmission:	
20	Mona-Oquirrh 345kV/500kV Transmission Line	300,034,261
21	Energy Gateway Preliminary Engineering and Permitting	71,642,657
22	Sigurd-Red Butte-Crystal 345kV Line	47,503,892
23	Aeolus Clover 500kV Line	35,748,021
24	Southwest WY Silver Creek Build 138kV Line	12,889,716
25	Boardman - Hemingway - 500kV Line	9,681,638
26	Lake Side 2 Interconnect Q0301	8,830,060
27	Oquirrh-Terminal 345kV Line	8,029,016
28	Carbon County System Reinforcement	6,114,428
29	West Point-New 138kV Line & 40 MVA Substation	5,191,766
30	TOT 4A-4B Transmission Path Transfer Capacity	4,495,330
31	Vantage-Pomona Heights 230kV Line	4,352,705
32	Cameron-Milford 138kV Transmission	4,066,860
33	Clover Substation install 345-138kV Sub & Lines	3,854,410
34	Black Rock New 230-69kV Substation	3,551,291
35	Wallula-McNary 230kV Line	3,317,749
36	Dave Johnston U3 GSU Transformer	2,965,423
37	Jim Bridger U1 Replace / Rewind GSU	2,924,684
38	Facebook Data Center Phase 2 Tom McCall Industrial Park - 115kV Project	2,717,860
39	COPCO II 230-115kV Transformer - TPL002	2,596,348
40	Line 37 Convert to 115kV Build Nickel Mt Substation	2,569,936
41	Terminal Substation 345-138kV Trnsf to 700 MVA	2,451,088
42	Line 3 Convert to 115kV	2,141,572
43	TOTAL	1,250,513,185

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	UT-NERC Line Rating Project-Medium Priority Lines	1,867,897
2	Whetstone 230-115kV Sub Phase 1	1,815,737
3	Wyodak U1 - Generator Step-up Transformer Spare	1,794,746
4	Three Peaks Substation: Install 345kV Sub	1,787,373
5	Two Elks Intercon at Tri County Switchyard	1,624,967
6	West of Populus Transmission Path Upgrades	1,370,972
7	Malin Sub: Replace 500kV Circuit Switcher 11L2	1,369,534
8	Union Gap Pacific 115kV Reconductor	1,111,631
9	OR-NERC Line Rating Project-Medium Priority Lines	1,058,885
10		
11	Distribution:	
12	Fort Douglas-New 138-12.5kV Substation & Transfmr	5,986,249
13	WA Avian Protect Walla-Walla	1,192,472
14		
15	General:	
16	Mobile Radio Replacement Project	19,393,567
17	Cottonwood Prep Plant-Improvements	3,638,756
18	Data Center Switch Replacement	2,517,871
19	Starvout - Fort Rock Microwave Replacement	1,393,387
20	Spores Point - Starveout Microwave Replacement	1,177,613
21	Blowhard - Beaver Dam Microwave Replacement	1,124,346
22	Deer Creek - 1 Continuous Miner	1,055,692
23		
24	Miscellaneous Projects each under $1,000,000	94,611,619
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,250,513,185

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	7,062,181,013	7,062,181,013		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	571,953,425	571,953,425		
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):	33,676,768	33,676,768		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	605,630,193	605,630,193		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	218,137,370	218,137,370		
13	Cost of Removal	68,875,093	68,875,093		
14	Salvage (Credit)	6,631,943	6,631,943		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	280,380,520	280,380,520		
16	Other Debit or Cr. Items (Describe, details in footnote):	17,236,735	17,236,735		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	7,404,667,421	7,404,667,421		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	2,505,658,617	2,505,658,617		
21	Nuclear Production				
22	Hydraulic Production-Conventional	264,903,753	264,903,753		
23	Hydraulic Production-Pumped Storage				
24	Other Production	579,208,388	579,208,388		
25	Transmission	1,285,912,340	1,285,912,340		
26	Distribution	2,268,075,733	2,268,075,733		
27	Regional Transmission and Market Operation				
28	General	500,908,590	500,908,590		
29	TOTAL (Enter Total of lines 20 thru 28)	7,404,667,421	7,404,667,421		

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	$10,733,499
Account 143, Other accounts receivable, - depreciation expense billed to joint owners	202,129
Asset retirement obligation asset depreciation recorded as a regulatory asset or liability	5,558,918
Transportation depreciation allocated to O&M and construction based on usage activity	15,898,715
Account 503, Steam from other sources, - Blundell depletion	185,368
Account 503, Steam from other sources, - Blundell depreciation	1,098,139
Total other accounts	$33,676,768

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

Reclassification of accrued removal and spend on asset retirement obligations that were included in lines 3 and 13.	$12,287,596
Other items include:	4,949,139
- Recovery from third parties for asset relocations and damaged property	
- Insurance recoveries	
- Adjustments of reserve related to electric plant sold	
- Reclassifications from electric plant	
Total Other Debit or Cr. Items	$17,236,735

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

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PACIFIC MINERALS, INC.	1973		
2	Common Stock			1
3	Paid-in Capital			47,960,000
4	Undistributed Subsidiary Earnings			140,245,757
5	SUBTOTAL			188,205,758
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			5,886,201
26	SUBTOTAL			11,924,201
27				
28	PACIFICORP ENVIRONMENTAL REMEDIATION COMPANY	1994		
29	Paid-in Capital			14,719,625
30	Undistributed Subsidiary Earnings			5,785,167
31	SUBTOTAL			20,504,792
32				
33	FOSSIL ROCK FUELS, LLC	2011		
34	Paid-in Capital			20,320,000
35	Undistributed Subsidiary Earnings			-1,484
36	SUBTOTAL			20,318,516
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 81,763,431		TOTAL	240,956,268

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1		2
		47,960,000		3
11,143,226		151,388,983		4
11,143,226		199,348,984		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
30,776		5,916,977		25
30,776		11,954,977		26
				27
				28
				29
42,651			5,827,818	30
42,651			5,827,818	31
				32
				33
		27,762,429		34
-5,423		-6,907		35
-5,423		27,755,522		36
				37
				38
				39
				40
				41
11,211,230		239,062,484	5,827,818	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.: 30 Column: h

Effective July 1, 2012, PacifiCorp Environmental Remediation Company ("PERCo")was dissolved, and all assets and liabilities of PERCo were assumed by PacifiCorp.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	236,891,214	265,591,187	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)	106,787,597	83,816,884	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	65,342,036	98,097,803	Electric
8	Transmission Plant (Estimated)	507,347	750,972	Electric
9	Distribution Plant (Estimated)	17,729,257	13,817,380	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,198,530	6,041,605	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	196,564,767	202,524,644	
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)	433,455,981	468,115,831	

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

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

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

Mining materials and supplies	$	5,910,897
General plant materials and supplies		130,708
	$	6,041,605

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)	2013 No. (d)	2013 Amt. (e)
1	Balance-Beginning of Year	237,269.00		156,646.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	43,287.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Luminant Energy Co. LLC	80,134.00			
23					
24					
25					
26					
27					
28	Total	80,134.00			
29	Balance-End of Year	113,848.00		156,646.00	
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.

2014		2015		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
156,645.00		136,466.00		4,055,608.00		4,742,634.00		1
								2
								3
				156,645.00		156,645.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						43,287.00		18
								19
								20
								21
						80,134.00		22
								23
								24
								25
								26
								27
						80,134.00		28
156,645.00		136,466.00		4,212,253.00		4,775,858.00		29
								30
								31
								32
								33
								34
								35
2,259.00		2,259.00		110,921.00		119,957.00		36
				4,528.00		4,528.00		37
								38
				2,269.00		4,528.00		39
2,259.00		2,259.00		113,180.00		119,957.00		40
								41
								42
								43
								44
								45
								46

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22	UT-Naughton Unit #3 environmental					
23	upgrades		3,415,498	407	401,958	3,013,540
24	Plant located near Evanston, WY					
25	Date of Retirement: 10/12/2012					
26	Date of Commission Authorization:					
27	09/19/2012					
28	Amortization Period: 10/12/2012					
29	through 08/31/2014					
30						
31	Unrecovered Plant:					
32	WY-Naughton Unit #3 environmental					
33	upgrades		1,218,111	407	105,102	1,113,009
34	Plant located near Evanston, WY					
35	Date of Retirement: 10/22/2012					
36	Date of Commission Authorization:					
37	10/8/2012					
38	Amortization Period: 10/22/2012					
39	through 12/31/2014					
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL		4,633,609		507,060	4,126,549

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2012/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 690566	6,322	561.6	6,322	456
3	AREF 690831	3,155	561.6	3,155	456
4	AREF 709133	6,091	561.6	6,091	456
5	AREF 709137	2,883	561.6	2,883	456
6	AREF 723846	1,828	561.6	1,828	456
7	AREF 739339	35,509	561.6	35,509	456
8	AREF 754172	7,886	561.6	7,886	456
9	AREF 784538	13,917	561.6	13,917	456
10	AREF 792853	18,208	561.6	18,208	456
11	Legacy Study #1	3,968	561.6	3,968	456
12	AREF's 752193,752219,752241,752243	2,379	561.6		
13	AREF 758483	4,527	561.6		
14	AREF 759777	13,641	561.6		
15	AREF 759779	5,338	561.6		
16	AREF 760025	4,263	561.6		
17	AREF 648008	(2,054)	561.6		
18	Integrated Resource Planning Agrmt	1,234	107		
19	AREF 468352	918	107		
20	AREF 728784	693	107		
21	**Generation Studies**				
22	GIQ0187	57	561.7	57	456
23	GIQ0217	278	561.7	278	456
24	GIQ0252	265	561.7	265	456
25	GIQ0255	4,658	561.7	4,658	456
26	GIQ0306	490	561.7	490	456
27	GIQ0310	21	561.7	21	456
28	GIQ0311	15,832	561.7	15,832	456
29	GIQ0313	3,147	561.7	3,147	456
30	GIQ0314	21	561.7	21	456
31	GIQ0315	495	561.7	495	456
32	GIQ0316	2,689	561.7	2,689	456
33	GIQ0322	1,608	561.7	1,608	456
34	GIQ0332	1,742	561.7	1,742	456
35	GIQ0333	2,078	561.7	2,078	456
36	GIQ0335	3,900	561.7	3,900	456
37	GIQ0341	1,923	561.7	1,923	456
38	GIQ0356	1,058	561.7	1,058	456
39	GIQ0367	9,805	561.7	9,805	456
40					

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 740690	929	107		
3	AREF 741886	1,084	107		
4	AREF 752491	1,896	107		
5	AREF 758483	151	107		
6	AREF 781578	15,108	107		
7	AREF 802603	5,983	107		
8	AREF 805002	3,559	107		
9	AREF 806561	1,818	107		
10	AREF 806544	1,855	107		
11	AREF 806494	1,855	107		
12	AREF 807115	1,818	107		
13	AREFS 809254 & 809362	1,969	107		
14	AREFS 809252 & 890367	1,174	107		
15	AREFS 809397 & 809398	1,060	107		
16	AREFS 809337 & 809374	1,212	107		
17	AREFS 809340 & 809375	1,212	107		
18	AREFS 809357 & 809382	1,022	107		
19	AREFS 809355 & 809380	1,060	107		
20	AREFS 809353 & 809378	947	107		
21	**Generation Studies**				
22	GIQ0372	33,102	561.7	33,102	456
23	GIQ0373	1,207	561.7	1,207	456
24	GIQ0374	147	561.7	147	456
25	GIQ0375	10,420	561.7	10,420	456
26	GIQ0377	8,252	561.7	8,252	456
27	GIQ0384	10,606	561.7	10,606	456
28	GIQ0386	240	561.7	240	456
29	GIQ0389	3,153	561.7	3,153	456
30	GIQ0392	3,330	561.7	3,330	456
31	GIQ0393	23,065	561.7	23,065	456
32	GIQ0395	6,118	561.7	6,118	456
33	GIQ0396	204	561.7	204	456
34	GIQ0397	15,727	561.7	15,727	456
35	GIQ0398	1,736	561.7	1,736	456
36	GIQ0400	319	561.7	319	456
37	GIQ0401	21,175	561.7	21,175	456
38	GIQ0403	25,820	561.7	25,820	456
39	GIQ0404	16,067	561.7	16,067	456
40	GIQ0405	873	561.7	873	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	AREFS 809347 & 809376	795	107		
3	AREF 812779	3,408	107		
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	GIQ0406	6,841	561.7	6,841	456
23	GIQ0407	36,624	561.7	36,624	456
24	GIQ0408	4,261	561.7	4,261	456
25	GIQ0409	52,114	561.7	52,114	456
26	GIQ0410	328	561.7	328	456
27	GIQ0411	45,492	561.7	45,492	456
28	GIQ0412	4,164	561.7	4,164	456
29	GIQ0413	13,048	561.7	13,048	456
30	GIQ0414	23,787	561.7	23,787	456
31	GIQ0415	10,658	561.7	10,658	456
32	GIQ0416	783	561.7	783	456
33	GIQ0417	10,954	561.7	10,954	456
34	GIQ0418	2,681	561.7	2,681	456
35	GIQ0419	2,472	561.7	2,472	456
36	GIQ0420	17,419	561.7	17,419	456
37	GIQ0421	1,639	561.7	1,639	456
38	GIQ0422	10,939	561.7	10,939	456
39	GIQ0423	3,687	561.7	3,687	456
40	GIQ0424	2,247	561.7	2,247	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	GIQ0425	28,015	561.7	28,015	456
23	GIQ0426	10,864	561.7	10,864	456
24	GIQ0427	18,573	561.7	18,573	456
25	GIQ0428	391	561.7	391	456
26	GIQ0429	720	561.7	720	456
27	GIQ0430	14,642	561.7	14,642	456
28	GIQ0431	9,560	561.7	9,560	456
29	GIQ0432	9,777	561.7	9,777	456
30	GIQ0433	7,607	561.7	7,607	456
31	GIQ0434	727	561.7	727	456
32	GIQ0435	1,008	561.7	1,008	456
33	GIQ0436	4,351	561.7	4,351	456
34	GIQ0437	2,395	561.7	2,395	456
35	GIQ0438	2,657	561.7	2,657	456
36	GIQ0439	2,510	561.7	2,510	456
37	GIQ0440	3,057	561.7	3,057	456
38	GIQ0441	1,789	561.7	1,789	456
39	GIQ0442	7,272	561.7	7,272	456
40	GIQ0443	5,039	561.7	5,039	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	GIQ0444	916	561.7	916	456
23	GIQ0445	876	561.7	876	456
24	GIQ0446	1,101	561.7	1,101	456
25	Customer Studies Accrual	2,364	561.7		
26	GIQ0267	623	107		
27	GIQ1497	8,444	107		
28	GIQ1256	822	107		
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 - CA	(2,758,978)	2,127,030	908,431	133,534	-765,482
2	DSM Regulatory Asset - ID	2,734,590	3,375,960	908,431	5,599,309	511,241
3	DSM Regulatory Asset - UT	(4,822,974)	45,668,667	908,431	49,051,923	-8,206,230
4	DSM Regulatory Asset - WA	1,438,228	10,079,376	908	10,089,223	1,428,381
5	DSM Regulatory Asset - WY	138,393	3,893,476	908,431	3,439,874	591,995
6	DSM Regulatory Asset - OR	26,627	20,537	908	47,164	
7	Alternative Rate For Energy (CARE) - CA	(237,632)	65,689	142,431	450,039	-621,982
8	2006 Transition Plan - OR (2)	912,507	4,862	920,254	917,369	
9	2006 Transition Plan - CA (1)	44,554		920	44,554	
10	Deferred Income Taxes Electric	443,887,834	11,872,657			455,760,491
11	Deferral of Interest on Uncertain Tax Positions-UT	1,972,627		431	1,972,627	
12	Deferral of Interest on Uncertain Tax Positions-WY	531,334		431	531,334	
13	Deferral of Interest on Uncertain Tax Positions-ID	271,404		431	271,404	
14	Tax Revenue Requirement Adjustment - WY	70,531				70,531
15	Deferred Excess Net Power Costs/ECAC - CA (1)	2,107,096	344	555,431	495,101	1,612,339
16	Deferred Excess Net Power Costs/ECAC - CA 2012		1,078,176			1,078,176
17	Deferred Excess Net Power Costs - WY 2010 (1)	3,249,063	506,547	555	3,755,610	
18	Deferred Excess Net Power Costs - WY 2011 (3)	32,442,978	360,771	555,182.3	12,962,759	19,840,990
19	Deferred Excess Net Power Costs - WY 2012		16,158,619			16,158,619
20	Deferred Excess Net Power Costs - WA Hydro (3)	816,688	7,969	555	928,405	-103,748
21	Deferred Excess Net Power Costs - ID 2010 (1)	5,049,290	9,795	555,182.3	5,059,085	
22	Deferred Excess Net Power Costs - ID 2011 (1)	10,484,722	3,104,153	555	10,597,959	2,990,916
23	Deferred Excess NPC - ID 2011 Monsanto (3)	7,213,116	45,675	555	2,178,687	5,080,104
24	Deferred Excess NPC - ID 2011 Agrium (3)	514,074	2,820	555	281,825	235,069
25	Deferred Excess Net Power Costs - ID 2012		8,099,210			8,099,210
26	Deferred Excess NPC - ID 2012 Monsanto		5,904,771			5,904,771
27	Deferred Excess NPC - ID 2012 Agrium		433,113			433,113
28	Deferred Excess Net Power Costs - ID 2013		205,171			205,171
29	Deferred Excess NPC - ID 2013 Monsanto		150,215			150,215
30	Deferred Excess NPC - ID 2013 Agrium		10,991			10,991
31	Deferred Excess NPC - UT Pre Oct 2011 (3)	59,188,678		555,431	11,514,737	47,673,941
32	Deferred Excess NPC - UT Oct 2011-Dec2011	8,598,582	921,008			9,519,590
33	Deferred Excess Net Power Costs - UT 2012		15,927,630			15,927,630
34	Deferred Excess RECs in Rates - UT 2010-Aug 2011	(371,950)	1,784,625	182.3	1,412,675	
35	Deferred Excess RECs in Rates - UT Sep'11-Dec2011	355,313	1,412,675	456,419	1,767,988	
36	Deferred Excess RECs in Rates/RBA - UT 2012			456,419	2,753,648	-2,753,648
37	Deferred Excess RECs in Rates - WA	681,343	755,164	456	1,436,507	
38	Deferred Excess RECs in Rates - WY 2010-2011 (1)	1,342,787	1,639,822	182.3	2,982,609	
39	Deferred Excess RECs in Rates - WY 2011-2012 (1)	(1,859,952)	4,018,944	456	1,330,409	828,583
40	Deferred Excess RECs/SO2 in Rates/RRA - WY 2012		587,013			587,013
41	Environmental Costs (10)	9,668,110	3,961,823	925	1,870,953	11,758,980
42	Environmental Costs - WA (10)	(750,287)	138,196	925	293,244	-905,335
43	Reg Asset - Environmental Costs	12,555,829	9,106,729			21,662,558

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Cholla Plant Transaction Costs (26)	5,240,697	183,792	557	1,122,425	4,302,064
2	Washington Colstrip #3 (22)	474,071		456	52,188	421,883
3	Unamortized Contract Values	186,949,133		242	20,921,106	166,028,027
4	Derivative Net Regulatory Asset	263,192,671		175,244	142,823,220	120,369,451
5	Asset Retirement Obligations Regulatory Difference	48,958,738	6,492,666			55,451,404
6	Pension/Other Postretirement	728,497,656	86,811,793		39,343,723	775,965,726
7	RTO Grid West N/R - OR (3)	355,527	2,274	904	363,836	-6,035
8	Deferred Independent Evaluator Fee - UT (1)	75,740	81,912	557	272,592	-114,940
9	Deferred Independent Evaluator Fee - OR (1)	(191,894)	289,616	419	522	97,200
10	Deferred Intervenor Funding Grants - CA	32,885	67			32,952
11	Deferred Intervenor Funding Grants - ID (2)	58,702	49,705	928	39,201	69,206
12	Deferred Intervenor Funding Grants - OR	345,643	239,893			585,536
13	BPA Balancing Account - ID	1,294,754		440,442	1,037,524	257,230
14	Renewable Adjustment Clause - OR (1)	(70,249)	116,227		45,978	
15	Goodnoe Hills Settlement - WY (24)	467,500		930.2	21,250	446,250
16	Lake Side Settlement - WY (39)	977,176		930.2	27,429	949,747
17	SB 408 Regulatory Asset - OR (1)	6,907,908	21,179		6,940,921	-11,834
18	SB 408 Regulatory Asset - MCBIT (1)	(49,394)	50,469	431	145	930
19	Chehalis Generating Facility Deferral - WA (6)	12,000,000			3,000,000	9,000,000
20	Powerdale Decommissioning - ID (10)	212,720	5,226	407.3	24,315	193,631
21	Powerdale Decommissioning - WA (3)	638,841		407.3	283,929	354,912
22	Powerdale Decommissioning - CA (2)	33,069		407.3	33,069	
23	Solar Feed-In Tariff Deferral - OR (1)	1,270,447	2,332,337		851,297	2,751,487
24	Solar Feed-In Tariff Deferral - CA	(246,352)	901,742		1,009,460	-354,070
25	Solar Incentive Program - UT		86,653		953,696	-867,043
26	Tax Adj on Postretirement Benefits - CA (3)	255,623		283,410.1	127,810	127,813
27	Tax Adj on Postretirement Benefits - ID (4)	614,991		283,410.1	204,997	409,994
28	Tax Adj on Postretirement Benefits - OR	4,471,643				4,471,643
29	Tax Adj on Postretirement Benefits - UT (4)	4,320,249		283,410.1	1,570,999	2,749,250
30	Tax Adj on Postretirement Benefits - WY (4)	1,677,403		283,410.1	559,134	1,118,269
31	Storm Damage Deferral - CA (1)	65,994		924	65,994	
32	Deferred Overburden Cost - ID	176,052	525,523	501	532,342	169,233
33	Deferred Overburden Cost - WY	487,998	1,457,982	501	1,479,092	466,888
34	Postemployment Costs		9,319,541		1,093,000	8,226,541
35	Naughton Unit No. 3 Environmental Costs		102,043			102,043
36	Naughton Unit No. 3 Environmental Costs - ID		478,988			478,988
37	Klamath Hydroelectric Relicensing Costs - UT (10)		35,697,674	404	988,285	34,709,389
38	Regulatory Assets - Reclassifications	9,545,204	7,981,448			17,526,652
39						
40						
41						
42						
43						
44	**TOTAL :**	1,874,535,671	306,668,973		359,960,034	1,821,244,610

Schedule Page: 232 Line No.: 10 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: 232.1 Line No.: 3 Column: a

Weighted average remaining life is 9 years. Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value.

Schedule Page: 232.1 Line No.: 4 Column: a

Weighted average remaining life is 1 year.

Schedule Page: 232.1 Line No.: 6 Column: a

Weighted average remaining life is 9 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: 232.1 Line No.: 6 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.: 14 Column: d

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

Schedule Page: 232.1 Line No.: 17 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.: 23 Column: d

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: 232.1 Line No.: 24 Column: d

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: 232.1 Line No.: 25 Column: d

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: 232.1 Line No.: 34 Column: a

Weighted average remaining life is 6 years.

Schedule Page: 232.1 Line No.: 34 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.: 38 Column: f

The following schedule summarizes regulatory assets reclassifications:

	As of December 31, 2012
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset - CA	$ 765,482

DSM Regulatory Asset - UT	8,206,230
Alternative Rate For Energy (CARE) - CA	621,982
Deferred Excess Net Power Costs - WA Hydro	103,748
Deferred Excess RECs in Rates/RBA - UT 2012	2,753,648
RTO Grid West N/R - OR	6,035
Deferred Independent Evaluator Fee - UT	114,940
SB 408 Regulatory Asset - OR and MCBIT	10,904
Solar Feed-In Tariff Deferral - CA	354,070
Solar Incentive Program - UT	867,043
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Injuries & Damage Reserve - OR	614,814
Property Insurance Reserve - OR	3,107,756
	$ 17,526,652

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

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Joseph Settlement (21)	835,733		557	137,381	698,352
2						
3	Lacomb Irrigation (24)	461,010		557	45,720	415,290
4						
5	Bogus Creek (41)	1,159,280		557	41,280	1,118,000
6						
7	Mead Phoenix Availability and					
8	Transmission Charge (50)	13,379,000		565	377,760	13,001,240
9						
10	TGS Buyout (23)	125,078		557	15,474	109,604
11						
12	Point to Point Transmission	3,041,984	971,548	142	1,233,569	2,779,963
13						
14	Jim Boyd Hydro Buyout (11)	172,625		557	82,860	89,765
15						
16	Hermiston Swap (40)	4,220,791		557	171,693	4,049,098
17						
18	LGIA LT Transmission Prepaid	1,946,280	66,334	565	2,012,614	
19						
20	Deferred Longwall Costs	919,138	4,019,692	151	3,803,406	1,135,424
21						
22	Deferred Coal Costs - Wyodak					
23	Settlement (22)	3,687,000		151	335,182	3,351,818
24						
25	Deferred Coal Costs - Naughton					
26	Settlement (7)	6,880,769		151	1,376,154	5,504,615
27						
28	Deferred Coal Costs - Jim					
29	Bridger Plant		2,916,673			2,916,673
30						
31	Deferred Colstrip Plant					
32	Costs (5)	1,225,000		501	300,000	925,000
33						
34	Deferred Royalty Reduction -					
35	Craig Plant		742,039			742,039
36						
37	LT Lease Commissions					
38	Prepaids (10)	556,839		931	92,819	464,020
39						
40	Lake Side Maintenance Prepaid	11,127,700	6,930,949			18,058,649
41						
42	Chehalis Maintenance Prepaid	7,429,493	2,289,177			9,718,670
43						
44	Currant Creek Maint. Prepaid	11,484,936	5,528,332	107	16,200,336	812,932
45						
46	Lease Incentives (10)	960,109		454	155,119	804,990
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	88,864,233				86,782,863

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)	594,513	2,020,934	427,431	697,735	1,917,712
3						
4	PCRB LOC/SBBPA Costs	139,592	385,826	427	322,136	203,282
5						
6	PCRB Mode Conversion Costs	269,044		427	123,429	145,615
7						
8	'94 Series Restruct. Costs	871,450		427	116,982	754,468
9						
10	LT Prepaid IBEW 57 Pension					
11	Contribution	5,651,545	282,569			5,934,114
12						
13	BPA LT Transmission Prepaid	8,584,039	296,276	565	863,304	8,017,011
14						
15	Emission Reduction Credits	2,631,396				2,631,396
16						
17	Unamortized contract values	478,212		174	56,643	421,569
18						
19	Sales of Electric Utility					
20	Facilities & Properties	1,677	73,325	539	13,448	61,554
21						
22	Other Current Deferred Charges	30,000		131	30,000	
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	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	88,864,233				86,782,863

Schedule Page: 233.1 Line No.: 4 Column: a

Weighted average life is 2 years.

Schedule Page: 233.1 Line No.: 6 Column: a

Weighted average life is 8 years.

Schedule Page: 233.1 Line No.: 8 Column: a

Weighted average life is 16 years.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	209,587,367	216,807,008
3	State Carryforwards	62,018,522	69,029,182
4	Unamortized Contract Values	72,107,587	63,351,855
5	Derivative Contracts	99,884,250	45,681,407
6	Regulatory Liabilities	43,186,293	39,958,098
7	Other	152,861,736	213,391,455
8	TOTAL Electric (Enter Total of lines 2 thru 7)	639,645,755	648,219,005
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)	639,645,755	648,219,005

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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, 2012, 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Scottish Power plc 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, 2012.

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 Internal Revenue Code 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Bonds: (Account 221)		
2	First Mortgage Bonds:		
3			
4	8.493% Series due October 1, 2012	19,772,000	
5	8.797% Series due October 1, 2013	16,203,000	
6	5.45% Series due September 15, 2013	200,000,000	1,422,659
7			232,000 D
8	4.95% Series due August 15, 2014	200,000,000	1,442,365
9			728,000 D
10	8.734% Series due October 1, 2014	28,218,000	
11	8.294% Series due October 1, 2015	46,946,000	
12	8.635% Series due October 1, 2016	18,750,000	
13	8.470% Series due October 1, 2017	19,609,000	
14	5.65% Series due July 15, 2018	500,000,000	3,067,221
15			905,000 D
16	5.50% Series due January 15, 2019	350,000,000	2,515,793
17			2,292,500 D
18	3.85% Series due June 15, 2021	400,000,000	3,007,139
19			744,000 D
20	2.95% Series due February 1, 2022	350,000,000	2,423,808
21			308,000 D
22	2.95% Series due February 1, 2022	100,000,000	254,129
23			-81,000 P
24	7.70% Series due November 15, 2031	300,000,000	2,874,150
25			864,000 D
26	5.90% Series due August 15, 2034	200,000,000	1,892,365
27			722,000 D
28	5.25% Series due June 15, 2035	300,000,000	2,912,021
29			1,080,000 D
30	6.10% Series due August 1, 2036	350,000,000	2,907,881
31			1,141,000 D
32			
33	TOTAL	7,027,868,000	78,659,157

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	10/01/2012	04/15/1992	10/01/2012		118,923	4
04/15/1992	10/01/2013	04/15/1992	10/01/2013	1,536,000	228,348	5
09/08/2003	09/15/2013	09/08/2003	09/15/2013	200,000,000	10,900,000	6
						7
08/24/2004	08/15/2014	08/24/2004	08/15/2014	200,000,000	9,900,000	8
						9
04/15/1992	10/01/2014	04/15/1992	10/01/2014	5,038,000	585,506	10
04/15/1992	10/01/2015	04/15/1992	10/01/2015	11,594,000	1,166,136	11
04/15/1992	10/01/2016	04/15/1992	10/01/2016	5,989,000	595,707	12
04/15/1992	10/01/2017	04/15/1992	10/01/2017	7,377,000	697,822	13
07/17/2008	07/15/2018	07/17/2008	07/15/2018	500,000,000	28,250,000	14
						15
01/08/2009	01/15/2019	01/08/2009	01/15/2019	350,000,000	19,250,000	16
						17
05/12/2011	06/15/2021	05/12/2011	06/15/2021	400,000,000	15,400,000	18
						19
01/06/2012	02/01/2022	01/06/2012	02/01/2022	350,000,000	9,799,190	20
						21
03/06/2012	02/01/2022	03/06/2012	02/01/2022	100,000,000	2,799,768	22
						23
11/21/2001	11/15/2031	11/21/2001	11/15/2031	300,000,000	23,100,000	24
						25
08/24/2004	08/15/2034	08/24/2004	08/15/2034	200,000,000	11,800,000	26
						27
06/13/2005	06/15/2035	06/13/2005	06/15/2035	300,000,000	15,750,000	28
						29
08/10/2006	08/01/2036	08/10/2006	08/01/2036	350,000,000	21,350,000	30
						31
						32
				6,820,029,000	355,713,688	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	5.75% Series due April 1, 2037	600,000,000	589,216
2			24,000 D
3	6.25% Series due October 15, 2037	600,000,000	5,127,281
4			750,000 D
5	6.35% Series due July 15, 2038	300,000,000	2,290,333
6			1,671,000 D
7	6.00% Series due January 15, 2039	650,000,000	6,134,687
8			6,175,000 D
9	4.10% Series due February 1, 2042	300,000,000	2,737,549
10			987,000 D
11	8.26% Series C Medium-Term Notes due Jan. 10, 2012	1,000,000	7,649
12	8.28% Series C Medium-Term Notes due Jan. 10, 2012	2,000,000	13,297
13	8.25% Series C Medium-Term Notes due Feb. 1, 2012	3,000,000	22,946
14	8.13% Series E Medium-Term Notes due Jan. 22, 2013	10,000,000	75,827
15	8.53% Series C Medium-Term Notes due Dec. 16, 2021	15,000,000	115,202
16	8.375% Series C Medium-Term Notes due Dec. 31, 2021	5,000,000	38,400
17	8.26% Series C Medium-Term Notes due Jan. 7, 2022	5,000,000	33,243
18	8.27% Series C Medium-Term Notes due Jan. 10, 2022	4,000,000	30,594
19	8.05% Series E Medium-Term Notes due Sept. 1, 2022	15,000,000	131,471
20	8.07% Series E Medium-Term Notes due Sept. 9, 2022	8,000,000	70,118
21	8.12% Series E Medium-Term Notes due Sept. 9, 2022	50,000,000	438,238
22	8.11% Series E Medium-Term Notes due Sept. 9, 2022	12,000,000	105,177
23	8.05% Series E Medium-Term Notes due Sept. 14, 2022	10,000,000	87,648
24	8.08% Series E Medium-Term Notes due Oct. 14, 2022	26,000,000	208,198
25	8.08% Series E Medium-Term Notes due Oct. 14, 2022	25,000,000	200,190
26	8.23% Series E Medium-Term Notes due Jan. 20, 2023	5,000,000	37,914
27	8.23% Series E Medium-Term Notes due Jan. 20, 2023	4,000,000	30,331
28			-81,560 P
29	7.26% Series F Medium-Term Notes due July 21, 2023	27,000,000	246,981
30	7.26% Series F Medium-Term Notes due July 21, 2023	11,000,000	100,622
31	7.23% Series F Medium-Term Notes due Aug. 16, 2023	15,000,000	137,211
32	7.24% Series F Medium-Term Notes due Aug. 16, 2023	30,000,000	274,423
33	TOTAL	7,027,868,000	78,659,157

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
03/14/2007	04/01/2037	03/14/2007	04/01/2037	600,000,000	34,500,000	1
						2
10/03/2007	10/15/2037	10/03/2007	10/15/2037	600,000,000	37,500,000	3
						4
07/17/2008	07/15/2038	07/17/2008	07/15/2038	300,000,000	19,050,000	5
						6
01/08/2009	01/15/2039	01/08/2009	01/15/2039	650,000,000	39,000,000	7
						8
01/06/2012	02/01/2042	01/06/2012	02/01/2042	300,000,000	12,129,167	9
						10
01/09/1992	01/10/2012	01/09/1992	01/10/2012		2,065	11
01/10/1992	01/10/2012	01/10/1992	01/10/2012		4,140	12
01/15/1992	02/01/2012	01/15/1992	02/01/2012		20,625	13
01/20/1993	01/22/2013	01/20/1993	01/22/2013	10,000,000	813,000	14
12/16/1991	12/16/2021	12/16/1991	12/16/2021	15,000,000	1,279,500	15
12/31/1991	12/31/2021	12/31/1991	12/31/2021	5,000,000	418,750	16
01/08/1992	01/07/2022	01/08/1992	01/07/2022	5,000,000	413,000	17
01/09/1992	01/10/2022	01/09/1992	01/10/2022	4,000,000	330,800	18
09/18/1992	09/01/2022	09/18/1992	09/01/2022	15,000,000	1,207,500	19
09/09/1992	09/09/2022	09/09/1992	09/09/2022	8,000,000	645,600	20
09/11/1992	09/09/2022	09/11/1992	09/09/2022	50,000,000	4,060,000	21
09/11/1992	09/09/2022	09/11/1992	09/09/2022	12,000,000	973,200	22
09/14/1992	09/14/2022	09/14/1992	09/14/2022	10,000,000	805,000	23
10/15/1992	10/14/2022	10/15/1992	10/14/2022	26,000,000	2,100,800	24
10/15/1992	10/14/2022	10/15/1992	10/14/2022	25,000,000	2,020,000	25
01/20/1993	01/20/2023	01/20/1993	01/20/2023	5,000,000	411,500	26
01/29/1993	01/20/2023	01/29/1993	01/20/2023	4,000,000	329,200	27
						28
07/22/1993	07/21/2023	07/22/1993	07/21/2023	27,000,000	1,960,200	29
07/22/1993	07/21/2023	07/22/1993	07/21/2023	11,000,000	798,600	30
08/16/1993	08/16/2023	08/16/1993	08/16/2023	15,000,000	1,084,500	31
08/16/1993	08/16/2023	08/16/1993	08/16/2023	30,000,000	2,172,000	32
				6,820,029,000	355,713,688	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	6.75% Series F Medium-Term Notes due Sept. 14, 2023	5,000,000	38,250
2	6.75% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
3	6.72% Series F Medium-Term Notes due Sept. 14, 2023	2,000,000	15,300
4	6.75% Series F Medium-Term Notes due Oct. 26, 2023	20,000,000	152,326
5	6.75% Series F Medium-Term Notes due Oct. 26, 2023	16,000,000	121,861
6	6.75% Series F Medium-Term Notes due Oct. 26, 2023	12,000,000	91,396
7	6.71% Series G Medium-Term Notes due Jan. 15, 2026	100,000,000	904,467
8	Subtotal - First Mortgage Bonds	6,289,498,000	63,804,117
9			
10	Pollution Control Obligations - Secured by Pledged First Mortgage Bonds:		
11			
12	Poll Ctrl Rev Refunding Bonds, Moffat County, CO, Series 1994	40,655,000	874,159
13	5-5/8% Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1993	8,300,000	228,980
14			197,125 D
15	5.65% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993A	46,500,000	1,624,793
16	5-5/8% Poll Ctrl Rev Refunding Bonds, Emery County, Utah, Series 1993B	16,400,000	625,551
17			389,500 D
18	Poll Ctrl Rev Refunding Bonds, Sweetwater County, WY, Series 1994	21,260,000	510,479
19	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1994	8,190,000	209,777
20	Poll Ctrl Rev Refunding Bonds, Emery County, UT, Series 1994	121,940,000	3,274,246
21	Poll Ctrl Rev Refunding Bonds, Carbon County, UT, Series 1994	9,365,000	206,519
22	Poll Ctrl Rev Refunding Bonds, Lincoln County, WY, Series 1994	15,060,000	422,858
23	Poll Ctrl Rev Refunding Bonds, Converse County, WY, Series 1988	17,000,000	155,970
24	Poll Ctrl Revenue Bonds, Sweetwater County, WY, Series 1984	15,000,000	122,887
25			105,000 D
26	Poll Ctrl Rev Refunding Bonds, Lincoln Cnty, WY, Series 1991	45,000,000	771,836
27	Poll Ctrl Revenue Bonds, City of Forsyth, MT, Series 1986	8,500,000	304,824
28	Environ. Imprvmnt Rev Bonds, Converse County, WY, Series 1995	5,300,000	132,043
29	Environ. Imprvmnt Rev Bonds, Lincoln County, WY, Series 1995	22,000,000	404,262
30	Subtotal Pollution Control Obligations - Secured by Pledged First Mortgage Bonds	400,470,000	10,560,809
31			
32			
33	TOTAL	7,027,868,000	78,659,157

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
09/14/1993	09/14/2023	09/14/1993	09/14/2023	5,000,000	337,500	1
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	135,000	2
09/14/1993	09/14/2023	09/14/1993	09/14/2023	2,000,000	134,400	3
10/26/1993	10/26/2023	10/26/1993	10/26/2023	20,000,000	1,350,000	4
10/26/1993	10/26/2023	10/26/1993	10/26/2023	16,000,000	1,080,000	5
10/26/1993	10/26/2023	10/26/1993	10/26/2023	12,000,000	810,000	6
01/23/1996	01/15/2026	01/23/1996	01/15/2026	100,000,000	6,710,000	7
				6,165,534,000	346,277,447	8
						9
						10
						11
11/17/1994	05/01/2013	11/17/1994	05/01/2013	40,655,000	343,070	12
11/15/1993	11/01/2021	11/15/1993	11/01/2021		117,912	13
						14
11/15/1993	11/01/2023	11/15/1993	11/01/2023		663,357	15
11/15/1993	11/01/2023	11/15/1993	11/01/2023		232,983	16
						17
11/17/1994	11/01/2024	11/17/1994	11/01/2024	21,260,000	191,712	18
11/17/1994	11/01/2024	11/17/1994	11/01/2024	8,190,000	64,377	19
11/17/1994	11/01/2024	11/17/1994	11/01/2024	121,940,000	955,581	20
11/17/1994	11/01/2024	11/17/1994	11/01/2024	9,365,000	72,201	21
11/17/1994	11/01/2024	11/17/1994	11/01/2024	15,060,000	136,213	22
01/01/1988	01/01/2014	01/01/1988	01/01/2014	17,000,000	680,352	23
12/01/1984	12/01/2014	12/01/1984	12/01/2014	15,000,000	600,357	24
						25
01/17/1991	01/01/2016	01/17/1991	01/01/2016	45,000,000	521,616	26
12/01/1986	12/01/2016	12/01/1986	12/01/2016	8,500,000	359,450	27
11/17/1995	11/01/2025	11/17/1995	11/01/2025	5,300,000	224,251	28
11/17/1995	11/01/2025	11/17/1995	11/01/2025	22,000,000	958,715	29
				329,270,000	6,122,147	30
						31
						32
				6,820,029,000	355,713,688	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Pollution Control Obligations - Unsecured		
2			
3	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988B	11,500,000	84,822
4	Poll Ctrl Rev Refndng Bonds, Sweetwater County, WY, Ser. 1990A	70,000,000	660,750
5	Poll Ctrl Rev Refndng Bonds, Emery County, UT, Series 1991	45,000,000	872,505
6	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1988A	50,000,000	422,443
7	Poll Ctrl Rev Refndng Bonds, City of Forsyth, MT, Series 1988	45,000,000	380,198
8	Poll Ctrl Rev Refndng Bonds, City of Gillette, WY, Ser. 1988	41,200,000	351,905
9	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992A	9,335,000	167,524
10	Poll Ctrl Rev Refndng Bonds, Sweetwater Cnty, WY, Ser. 1992B	6,305,000	151,908
11	Poll Ctrl Rev Refndng Bonds, Converse County, WY, Series 1992	22,485,000	242,163
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	7,027,868,000	78,659,157
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	7,027,868,000	78,659,157

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
01/01/1988	01/01/2014	01/01/1988	01/01/2014	11,500,000	106,247	3
07/25/1990	07/01/2015	07/25/1990	07/01/2015	70,000,000	638,712	4
05/23/1991	07/01/2015	05/23/1991	07/01/2015	45,000,000	496,614	5
01/01/1988	01/01/2017	01/01/1988	01/01/2017	50,000,000	493,246	6
01/01/1988	01/01/2018	01/01/1988	01/01/2018	45,000,000	402,885	7
01/01/1988	01/01/2018	01/01/1988	01/01/2018	41,200,000	375,211	8
09/29/1992	12/01/2020	09/29/1992	12/01/2020	9,335,000	93,882	9
09/29/1992	12/01/2020	09/29/1992	12/01/2020	6,305,000	64,397	10
09/29/1992	12/01/2020	09/29/1992	12/01/2020	22,485,000	221,844	11
12/14/1995	11/01/2025	12/14/1995	11/01/2025	24,400,000	228,343	12
09/24/1996	09/01/2030	09/24/1996	09/01/2030		192,713	13
						14
						15
				325,225,000	3,314,094	16
						17
						18
				6,820,029,000	355,713,688	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				6,820,029,000	355,713,688	33

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

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022. 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 Line No.: 22 Column: a

In March 2012, PacifiCorp issued $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. State commission authorizations for this issuance were 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.

Schedule Page: 256.1 Line No.: 9 Column: a

In January 2012, PacifiCorp issued $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. State commission authorizations for this issuance were 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.

Schedule Page: 256.2 Line No.: 13 Column: a

In March 2012, PacifiCorp redeemed: the 5-5/8% Pollution Control Revenue Refunding Bonds, Lincoln County, WY, Series 1993; the 5.65% Pollution Control Revenue Refunding Bonds, Emery County, Utah, Series 1993A; the 5-5/8% Pollution Control Revenue Refunding Bonds, Emery County, Utah, Series 1993B; and the 6.150% Environmental Improvement Revenue Bonds, Emery County, Utah, Series 1996. PacifiCorp transferred the unamortized debt expense and unamortized discount associated with these obligations to Account 189, Unamortized loss on reacquired debt.

Schedule Page: 256.2 Line No.: 15 Column: a

See footnote on page 256.2 for column (a) line 13.

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

See footnote on page 256.2 for column (a) line 13.

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

See footnote on page 256.2 for column (a) line 13.

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

Refer to Important Changes During the Quarter/Year, Item 6, and Notes to Financial Statements, Note 7, of this Form No. 1 for a discussion of PacifiCorp's long-term debt.

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

Amount represents interest expense charged to Account 427, Interest on long-term debt, and does not include any amount charged to Account 430, Interest on debt to associated companies, as such associated debt is included in Account 233, Notes payable to associated companies.

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-3ASR 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; $850 million available as of December 31, 2012), refer to 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, 2012) by the counties of Emery, Utah; Carbon, Utah; Converse, Wyoming; Lincoln, Wyoming; Sweetwater, Wyoming; and Moffat, Colorado and authorization to borrow the proceeds of new pollution control revenue bonds issued (total of $150,000,000 authorized and available as of December 31, 2012) 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	537,337,285
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8	Other	51,249,086
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13	Other	1,240,796,851
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18	Other	143,683,817
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25	Other	1,728,327,545
26	State Tax Deductions	-781,504
27	Federal Tax Net Income	-43,409,644
28	Show Computation of Tax:	
29		
30	Federal Income Tax at 35.00%	-15,193,375
31	Provision to Return Adjustment	-23,310,753
32	Tax Reserve Changes	-3,125,404
33	Contingency Reserve	-1,500,000
34	Renewable Electricity Production Tax Credits	-65,383,088
35		
36	Federal Income Tax Accrual	-108,512,620
37		
38		
39		
40		
41		
42		
43		
44		

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

Particulars (Details)	Amounts
CIAC	$ 42,046,191
Reimbursements	1,070,419
OR SB 408 Recovery	6,919,741
Federal Benefit of Federal Interest - IRHI	430,600
Federal Benefit of State Interest - IRHI	642,887
State Benefit of Federal Interest - IRHI	55,856
State Benefit of State Interest - IRHI	83,392
Total	$ 51,249,086

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

Particulars (Details)	Amounts
Fed/State Tax Expense	$ 191,582,246
Book Depreciation Allocated to Medicare and M&E	49,253
Meals & Entertainment	865,355
Penalties	599,682
Lobbying expenses	1,739,242
Medicare Subsidy	3,006,171
Capitalized labor and benefits costs for Power tax input - Temporary	8,840,481
Book Depreciation	647,597,336
Avoided Costs	52,720,950
UT Klamath Relicensing Costs	35,306,774
Book Cost Depletion - Addback	2,040,779
Regulatory Asset - FAS 158 Pension Liability Adj.	35,309,000
Regulatory Asset - FAS 158 Post Ret. Liability	3,678,000
Environmental Costs - WA	155,047
Regulatory Asset - Utah ECAM	19,248,068
Cholla Plant Transaction Costs-APS Amortization	1,122,425
WA Disallowed Colstrip #3 - Write-off	52,188
Regulatory Asset - Lake Side Liquidation	27,429
Goodnoe Hills Liquidation Damages - WY	21,250
RTO Grid West Notes Receivable - OR	361,562
Regulatory Asset - Pension MMT - UT	283,176
Regulatory Asset - Post - Ret MMT - OR	193,035
Regulatory Asset - Post - Ret MMT - UT	278,648
Regulatory Asset - Post - Ret MMT - CA	17,488
Regulatory Asset - Powerdale Decommissioning - CA	33,069
Regulatory Asset - Powerdale Decommissioning - ID	19,089
Regulatory Asset - Powerdale Decommissioning - WA	283,929
CA - January 2010 Storm Costs	65,994
ID - Deferred Overburden Costs	6,819
WY - Deferred Overburden Costs	21,109
Regulatory Asset - CA Solar Feed-in Tariff	107,718
Regulatory Asset - UT - Solar Incentive Program	867,043
Deferred Excess Net Power Costs - WA Hydro	920,436
Deferred UT Independent Evaluation Fee	190,680
Deferral of Renewable Energy Credits	3,418,354
Deferred Excess Net Power Costs - ID 09	151,642
OR - MEHC Transition Service Costs	912,507
WA - Chehalis Plant Revenue Requirement	3,000,000
Regulatory Asset - MEHC Transition Service Costs - CA	44,554
Deferred Coal Costs - Naughton Contract Settlement	1,376,154
Contra Regulatory Asset - Naughton Unit #3 - OR	2,044,913
Contra Regulatory Asset - Naughton Unit #3 - WA	629,112
Idaho Customer Balancing Account	1,037,524
Weatherization	3,195,980
Prepaid Taxes - UT PUC	80,195

TGS Buyout	15,474
Joseph Settlement	137,381
Hermiston Swap	171,693
Western Coal Carrier Postretirement Benefit Accrual	861,000
Post Merger Loss - Reacquisition Debt - Addback	174,109
Regulatory Liability - UT Home Energy Lifeline	390,090
Regulatory Liability - WA Low Energy Program	334,199
OR Regulatory Asset/Liability Consolidation	90,182
CA - California Alternative Rate for Energy Program (CARE)	384,350
Regulatory Liability - Blue Sky Program OR	858,685
Regulatory Liability - Blue Sky Program WA	103,873
Regulatory Liability - Blue Sky Program CA	40,165
Regulatory Liability - Blue Sky Program UT	976,702
Regulatory Liability - Blue Sky Program ID	39,099
Regulatory Liability - Blue Sky Program WY	86,570
Regulatory Liability - CA GHG Allowance Revenues	2,434,345
Regulatory Liability - ID Property Insurance Reserve	113,544
Regulatory Liability - UT Property Insurance Reserve	1,230,954
Regulatory Liability - WY Property Insurance Reserve	349,810
Reg. Liab. - OR 2012 GRC outcome related to emission control equip. invest	17,000,000
Pension / Retirement Accrual - Cash Basis	33,837
Severance Accrual - Cash Basis	265,807
Distribution O&M Amortization of Write-off	3,113,202
R & E - Sec.174 Deduction	12,411
Bear River Settlement Agreement	312,552
USA Power litigation and certain fire and other damage claims	155,910,850
Lewis River Settlement Agreement	122,036
North Umpqua Settlement Agreement	1,292,207
Umpqua Settlement Agreement	21,695
Deferred Revenue - Citibank	334,699
Environmental Liability - Regulated	21,277,848
FAS 112 Book Reserve	8,779,723
Intercompany Adjustments	25,353
Total	$1,240,796,851

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

Particulars (Details)	Amounts
Fed/State Tax Expense - Interest	$ (2,431,029)
Utah Deferred Comp / COLI	(4,672,626)
Non-deductible post-retirement costs	(129,004)
Capitalized labor costs for PowerTax input - Medicare subsidy - Temporary	(862,862)
AFUDC - Equity	(57,888,665)
Gain / (Loss) on Property Disposition	(18,544,545)
Book Gain / Loss on Land Sales	(1,063,591)
Trapper Mining Stock Basis	(176,714)
Regulatory liability - BPA balancing accounts	(905,356)
Oregon Gain on Sale	(5,248)
Regulatory Liability - Sale of Renewable Energy Credits	(26,252,717)
Regulatory Liability - OR 2010 Protocol Def	(2,209,549)
Regulatory Liability - Powerdale Decommissioning Costs Giveback - UT	(360,556)
NW Power Act - WA	(669,786)
Regulatory Liability - SMUD Revenue Imputation - UT	(2,667,282)
Def Regulatory Asset - Foote Creek Contract	(137,640)
Tenant Lease Allow - PSU Call Center	(48,156)
Other Environmental Liabilities	(12,424,383)
Redding Contract - Prepaid	(549,996)
Unrealized Gain / Loss from Trading Securities	(472,882)
Equity Earnings in Subsidiaries	(11,211,230)
Total	$(143,683,817)

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Particulars (Details)	Amounts
Tax Percentage Depletion - Deer Creek	$ (3,014,768)
Tax Percentage Depletion - Blundell Steam Field (Prior IGC)	(462,728)
PPL Pre - 1943 Preferred Stock Div - Deduction	(381,063)
MEHC Insurance Services - Receivable	(2,022,305)
Dividend Received Deduction - Deferred Compensation	(128,428)
Income Tax Interest	(19,781)
PMI Overriding Coal Royalty % Depletion - PacifiCorp	(4,707)
Repair Deduction	(136,511,650)
Tax Depreciation	(1,275,554,480)
Capitalized Depreciation	(5,681,113)
AFUDC - Debt	(28,473,727)
Basis Intangible Difference	(887,984)
Coal Mine Development	(309,400)
Coal Mine Extension	(1,899,484)
Removal Costs	(68,875,093)
Cholla SHL-NOPA (Lease Amortization)	(115,687)
Tax Percentage Depletion - Deduction	(3,779,983)
Tax Depletion	(167,874)
Regulatory Asset - Post-Employment Costs	(8,226,541)
Environmental Clean-up Accrual	(11,197,600)
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	(67)
Deferred Intervenor Funding Grants	(239,892)
Contra Pension Regulatory Asset MMT & CTG - OR	(1,014,634)
Contra Pension Regulatory Asset MMT & CTG - CA	(91,920)
Contra Pension Regulatory Asset CTG - WA	(1,017,963)
Regulatory Asset - Deferred OR Independent Evaluator Fees	(289,093)
Unrecovered Plant - Powerdale	(80,564)
Regulatory Asset - OR Solar Feed-In Tariff	(1,481,040)
Deferred Excess Net Power Costs - CA	(583,419)
Deferred Excess Net Power Costs - WY 09 and After	(307,568)
Deferred Excess Net Power Costs - UT	(24,581,969)
Deferred Excess Net Power Costs - OR	(61,433)
Deferral of Renewable Energy Credits	(1,932,761)
OR _RCAC Sep-Dec 07 Deferred	(8,816)
Regulatory Asset - Naughton Unit #3 Costs	(2,776,068)
Regulatory Asset - UT - Naughton U3 Costs	(3,013,540)
Regulatory Asset - WY - Naughton U3 Costs	(1,113,009)
Regulatory Asset - ID - Naughton U3 Costs	(478,988)
Deferred Regulatory Expense	(10,505)
Regulatory Asset - UT - Klamath Hydro Relicensing Costs	(34,709,389)
Trojan Decommissioning Costs - Regulatory	(99,553)
Coal Pile Inventory Adjustment	(8,076,666)
Prepaid Taxes - OR PUC	(86,205)
Prepaid Taxes - ID PUC	(32,110)
Other Prepaid	(364,096)
Prepaid Taxes - Property Taxes	(3,793,091)
Wasach workers comp reserve	(348,094)
Regulatory Liability - OR Energy Conservation Charge	(4,947)
Regulatory Liability - OR Injuries & Damages Reserve	(801,169)
Regulatory Liability - OR Property Insurance Reserve	(6,079,456)
LT Prepaid IBEW 57 Pension Contribution	(282,568)
Bonus Liability - Electric - Cash Basis (2.5 months)	(49,539)
Vacation Accrual - Cash Basis (2.5 months)	(1,009,771)

Deferred Compensation Accrual - Cash Basis	(1,168,924)
Pension Liability	(68,246,000)
Post-Retirement Liability	(4,285,686)
SERP Liability	(818,472)
PMI-Fuel Cost Adjustment	(1,888,126)
M&S Inventory Write-Off	(484,494)
Bad Debts Allowance - Cash Basis	(3,423,593)
Def Regulatory Asset - Transmission Service Deposit	(614,690)
Rogue River - Habitat Enhancement Liability	(4,781)
Unearned Joint Use Pole Contact Revenue	(965,355)
Accrued Royalties	(157,057)
Misc. Current and Accrued Liability	(2,243,351)
Federal Benefit of State Tax - IRHI	(48,734)
Environmental Liability - Non-Regulated	(299,102)
Reverse Accrued Final Reclamation	(902,046)
Amortization NOPAs 99-00 RAR	(58,446)
MCI FOG Wire Lease	(597)
Total	$(1,728,327,545)

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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 United States Federal Income Tax Return:

Under MidAmerican Energy Holdings Company ("MEHC"):

PPW Holdings LLC Sub-Group:

PacifiCorp
PPW Holdings LLC

PacifiCorp Sub-Group:

Centralia Mining Company
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.
PacifiCorp Environmental Remediation Company
PacifiCorp Investment Management, Inc.

MEHC Sub-Group:

Alaska Gas Transmission Company, LLC
American Pacific Finance Company
American Pacific Finance Company II
Arizona HomeServices, LLC
AVSP 1A, LLC
AVSP 1B, LLC
AVSP 2A, LLC
AVSP 2B, LLC
AVSP Holding, LLC
BG Energy Holding Company LLC
BG Energy LLC
Bishop Hill Energy II, 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 Title Company
CBEC Railway, Inc
CBSHome Commercial, LLC
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
Century Development LLC
Champion Realty, Inc
Chancellor Title Services, Inc
Cimmred Leasing Company
Columbia Title of Florida, Inc
Connecticut Referral Group, L.L.C.
Cordova Energy Company, LLC
Cordova Funding Corporation
CTHM, L.L.C.
CTRE, L.L.C.
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
Fort Dearborn Land & Title Company
HMSV Financial Services, Inc
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 Connecticut, LLC
HomeServices of Florida, Inc
HomeServices of Illinois Holdings, LLC
HomeServices of Iowa, Inc
HomeServices of Kentucky, Inc
HomeServices of Nebraska, Inc
HomeServices of Oregon, LLC
HomeServices of the Carolinas, Inc
HomeServices of Washington, LLC
HomeServices Real Estate Academy
HomeServices Referral Network, LLC
HomeServices Relocation, LLC
HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
HS Franchise Holding, LLC
HSR Equity Funding, Inc
Huff Commercial Group, LLC
Huff-Drees Realty, Inc
IMO Company, Inc
InsuranceSouth, LLC
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, LLC
Kern River Funding Corporation
Kern River Gas Transmission Company
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Larabee School of Real Estate & Insurance, Inc
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
MEC Construction Services Company
MEHC America Transco LLC
MEHC Canada, LLC
MEHC Insurance Services Ltd.
MEHC Investment, Inc
MEHC Merger Sub 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 Renewables, LLC
MidAmerican Solar, LLC
MidAmerican Transmission, LLC

MidAmerican Wind, LLC
Midland Escrow Services, Inc
Midwest Capital Group, Inc
MWR Capital, Inc
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
NMA, LLC
NNGC Acquisition LLC
Northern Aurora Inc
Northern Natural Gas Company
NW Referral Services, LLC
PCRE, L.L.C.
Pickford Escrow Company, Inc
Pickford Holdings, LLC
Pickford Real Estate, Inc
Pickford Services Company, Inc
Pilot Butte, LLC
Pinyon Pines I Holding Company, LLC
Pinyon Pines II Holding Company, LLC
Pinyon Pines Wind I, LLC
Pinyon Pines Wind II, LLC
PNW Referral, LLC
Preferred Carolinas Realty, Inc
Preferred Carolinas Title Agency, LLC
Professional Referral Organization, Inc
Quad Cities Energy Company
Real Estate Knowledge Services, L.L.C.
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
Referral Network of IL LLC
Relocation Advantage Partners, LLC
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
TitleSouth, LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
Two Rivers, Inc
Wailuku Investment LLC
Wm Broughton, LLC

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

Berkshire Hathaway Inc. Sub-Group
121 Acquisition Co., LLC

21 SPC, Inc.
21st Communities, Inc.
21st Mortgage Corporation
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.
Affiliated Agency Operations Co.
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
AmGUARD Insurance Company
Anderson Retail, Inc.
Apeks Apparel, Inc.
Applied Group Insurance Holdings, Inc.
Applied Investigations Inc.
Applied Logistics, Inc.
Applied Premium Finance, Inc.
Applied Processing Center No. 60, 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 Holding Company, Inc.
B. Lippman
Bayport Systems, Inc.
Ben Bridge Jeweler, Inc.
Benjamin Moore & Co.
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 Columbia Inc.

BH Finance, Inc.
BH Shoe Holdings, Inc.
BH, LLC
BHG Life Insurance Company
BHG Structured Settlements, Inc.
BHSF, Inc.
Blue Chip Stamps
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 Owners Association of the United States
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.
California Insurance Company
Camp Manufacturing Company
Campbell Hausfeld/Scott Fetzer Company
Carefree/Scott Fetzer Company
Cavalier Homes, Inc.
Central States Indemnity Co. of Omaha
Central States of Omaha Companies, Inc.
Cerro Plumbing Retail, Inc.
Cerro Wire Distribution, Inc.
CG Service, Inc.
Chatwell, Inc.
Chippewa Shoe Company
Citadel Insurance Company
CJE II
Claims Services, Inc.
CLAL U.S. Holdings, 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
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.
Delta Wholesale Liquors, Inc.
Denver Brick Company
Dexter Shoe Company
DQ Funding Corporation
DQ Joint Venture Stores, Inc.
DQ Managed Stores, Inc.
DQ Wholly-Owned Stores, Inc.
DQF, Inc.
DQGC, Inc.
EastGUARD Insurance Company
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.
Exsif Worldwide, Inc.
Fairfield Insurance Company
Faraday Capital Limited
Farriors, Inc.
Finial Holdings, Inc.
Finial Reinsurance Company
First American Carriers, Inc.
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
Fontana Wood Products of Oregon, Inc.
Fontana Wood Products, Inc.
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 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.
GRD Holdings Corporation

Great Plains Uniforms
Griffey Uniforms
GUARD Financial Group, Inc.
GUARD Insurance Group, Inc.
GUARDco, Inc.
H. H. Brown Shoe Company, Inc.
H. H. Brown Shoe Technologies, LLC
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.
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.
Illinois Insurance Company
Innovative Building Products, Inc
InterGUARD, Ltd.
International America Group Inc.
International American Management Company
International Dairy Queen, Inc.
International Insurance Underwriters, Inc.
International Traders, Inc.
Intrepid JSB, Inc.
Ironwood Plastics Inc
Isabella Shoe Corporation, LLC
J.L. Mining Company
J.S Justin, Inc.
JDS Properties, 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
L.A. Terminals, Inc.
Leesburg Yarn Mills, Inc.
Lipotec Group Corp.
LMG Ventures, LLC
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, LLC
Mapletree Transportation, Inc.
Marathon Suspension Systems, Inc.
Marmon Crane Services, Inc.
Marmon Distribution Services, Inc.
Marmon Flow Products, Inc.
Marmon Holdings, Inc.
Marmon Industrial Companies, Inc.
Marmon Natural Resource & Transportation Service
Marmon Retail Home Improvement Products, 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 Beverage Distribution, Inc.
McLane Beverage Holding, 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.
Meadowbrook Meat Company, Inc.
Medical Protective Corporation
Medical Protective Finance Corporation
Medical Protective Insurance Services, Inc.
MedPro Risk Retention Services, Inc.
Metro Uniforms
MH Transport, 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
Nationwide Uniforms
Nebraska Furniture Mart, Inc.
NetJets Aviation, Inc.
NetJets Europe Holdings, LLC
NetJets Inc.
NetJets International, Inc.
NetJets Large Aircraft, Inc.
NetJets M.E., Inc.
NetJets Sales, Inc.
NetJets Services, Inc.
NetJets U.S., Inc.
NFM of Kansas, Inc.
NFM Services, LLC
Nick Bloom Uniforms
NJ Executive Services, Inc.
NJE Holdings, LLC
NJI Sales, Inc.
NJI, Inc.
Nocona Boot Company
NorGUARD Insurance Company
North American Casualty Co.
Northern States Agency, Inc.
Noveon Hilton Davis, Inc.
Oak River Insurance Company
Omaha World-Herald Company
Orange Julius Of America
Pan-Am Shoe Company, LLC
Penn Coal Land, Inc.
Penn Pocahontas Coal Co.
Pennsylvania Insurance Company
Perfection Hy-Test Company
Pima Uniforms
Pine Canyon Land Company
PJR Management, Inc.
Plaza Financial Services Co.
Plaza Resources Co.
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.
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
Scott Fetzer Financial Group, Inc.
ScottCare Corporation
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, LLC
Sol Frank Uniforms Inc.
Somerset Services, Inc
Southern Energy Homes, 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.
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.
TransGUARD, Ltd.
TRH Holding Corp.
Triangle Suspension Systems, Inc.
TSE Brakes, Inc.
TTI, Inc.
TXFM, Inc.
U.S. Investment Corporation
U.S. Underwriters Insurance Co.
Unified Supply Chain, Inc.
Uni-Form Components Co.
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, Incorporated
United States Liability Insurance Company
United Steel Products Company
Universal Uniforms
UTLX Company, Inc.
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 Association of America, Inc.
VFI-Mexico, Inc.
Vision Retailing, Inc.
Wayne/Scott Fetzer Company
Waynesburg Shirt Company Inc.
Webb Wheel Products, Inc.
Wells Lamont Retail, Inc.
Wesco Financial Corporation
Wesco Holdings Midwest, Inc.
Wesco-Financial Insurance Company
West Virginia Uniforms

Western Fruit Express Company
Western/Scott Fetzer Company
WestGUARD Insurance Company
Whittaker, Clark & Daniels, Inc.
Winona Bridge Railroad Company
WMC Corp.
World Book Encyclopedia, Inc.
World Book, Inc.
World Book/Scott Fetzer Company
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.
Zuckerbergs Uniforms

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

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	Income	17,233,393	66,373,297	-108,512,620	-208,990,602	96,987
3	FICA	430,018	11,403	36,461,124	36,450,728	
4	Unemployment	5,385		252,682	253,736	
5	Excise Tax - Coal	181,263		3,471,497	3,573,955	
6	Subtotal	17,850,059	66,384,700	-68,327,317	-168,712,183	96,987
7						
8	State:					
9						
10	Arizona:					
11	Property	1,304,599		2,854,938	2,732,068	
12	Income		-11,613	148,893	-44,924	
13	Subtotal	1,304,599	-11,613	3,003,831	2,687,144	
14						
15	California:					
16	Property			2,195,452	2,195,452	
17	Unemployment	2,089		33,917	35,886	
18	Franchise-Income		290,283	132,061	-20,099	
19	Use	39,948		127,080	153,690	
20	Local Franchise	1,183,958		1,240,533	1,169,205	
21	Subtotal	1,225,995	290,283	3,729,043	3,534,134	
22						
23	Colorado:					
24	Property	1,760,000		1,945,949	1,795,949	
25	Income		-1,544	583		
26	Subtotal	1,760,000	-1,544	1,946,532	1,795,949	
27						
28	Idaho:					
29	Property	2,994,775		5,468,390	5,323,123	
30	Income		214,046	584,571	343,708	-44,387
31	KWh	750		31,373	29,123	
32	Unemployment	1,140		57,700	57,384	
33	Use	16,152		116,755	117,639	
34	Subtotal	3,012,817	214,046	6,258,789	5,870,977	-44,387
35						
36	Montana:					
37	Property	1,416,093		3,554,804	3,194,779	
38	Corporate License-Income		-1,904	780	100	
39	Unemployment			1,307	1,307	
40	Energy License	57,564		230,563	228,127	
41	TOTAL	52,714,616	78,502,426	110,821,300	9,902,728	-276,749

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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
51,241,091		-106,857,967			-1,654,653	2
431,843	2,832				36,461,124	3
4,331					252,682	4
78,805					3,471,497	5
51,756,070	2,832	-106,857,967			38,530,650	6
						7
						8
						9
						10
1,427,469		2,854,938				11
205,430		153,465			-4,572	12
1,632,899		3,008,403			-4,572	13
						14
						15
		2,067,018			128,434	16
165	45				33,917	17
-138,123		137,879			-5,818	18
13,338					127,080	19
1,255,286		1,240,533				20
1,130,666	45	3,445,430			283,613	21
						22
						23
1,910,000		1,878,520			67,429	24
2,127		1,388			-805	25
1,912,127		1,879,908			66,624	26
						27
						28
3,140,042		5,313,125			155,265	29
71,204		599,321			-14,750	30
3,000		31,373				31
1,456					57,700	32
15,268					116,755	33
3,230,970		5,943,819			314,970	34
						35
						36
1,776,118		3,554,804				37
2,584		2,170			-1,390	38
					1,307	39
60,000		230,563				40
87,443,808	12,036,297	53,239,654			57,581,646	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	41,051		164,498	162,927	
2	Subtotal	1,514,708	-1,904	3,951,952	3,587,240	
3						
4	New Mexico:					
5	Property			6,721	6,721	
6	Income		-1,467	536	50	
7	Subtotal		-1,467	7,257	6,771	
8						
9	Oregon:					
10	Property		10,977,923	22,575,991	23,213,399	
11	Unemployment	58,472	7,745	1,653,470	1,671,754	
12	Wilsonville Payroll	534		2,358	2,217	
13	Excise-Income		-28,843	35,298	184,991	-204,909
14	City of Portland-Income		-2,559	-55,011	347	-59,737
15	Multnomah County			-37,138	827	-39,463
16	Department of Energy		424,705	838,377	827,343	
17	Tri-Met	338,552		968,660	925,873	
18	Lane County			2,173	2,173	
19	Franchise	4,404,572		26,908,113	26,910,471	
20	Subtotal	4,802,130	11,378,971	52,892,291	53,739,395	-304,109
21						
22	Utah:					
23	Property	435,289		61,064,550	61,581,025	
24	Income		167,657	19,121	-322,213	-137
25	Unemployment	7,545	-78	387,846	390,840	
26	Navajo Nation			608	608	
27	Use	434,708		3,909,249	4,057,485	
28	Franchise			217,772	217,772	
29	Subtotal	877,542	167,579	65,599,146	65,925,517	-137
30						
31	Washington:					
32	Property	9,040,000		9,709,015	9,349,015	
33	Unemployment	1,037		64,954	63,966	
34	Business & Occupation	3,414		35,435	35,336	
35	Wholesaling	371		689	1,060	
36	Public Utility	1,100,000		11,678,221	11,678,221	
37	Natural Gas Use Tax	185,392		1,202,887	1,343,621	
38	Use	622,123		675,875	687,323	
39	Franchise			500	500	
40	Subtotal	10,952,337		23,367,576	23,159,042	
41	TOTAL	52,714,616	78,502,426	110,821,300	9,902,728	-276,749

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
42,622		164,498				1
1,881,324		3,952,035			-83	2
						3
						4
		6,721				5
1,953		1,594			-1,058	6
1,953		8,315			-1,058	7
						8
						9
	11,615,331	21,790,404			785,587	10
36,861	4,418				1,653,470	11
675					2,358	12
84,059		137,564			-102,266	13
6,938		-53,007			-2,004	14
1,498		-37,138				15
	413,671	838,377				16
381,339					968,660	17
					2,173	18
4,402,214		26,908,113				19
4,913,584	12,033,420	49,584,313			3,307,978	20
						21
						22
-81,186		54,532,817			6,531,733	23
173,814		111,298			-92,177	24
4,629					387,846	25
		608				26
286,472					3,909,249	27
		217,772				28
383,729		54,862,495			10,736,651	29
						30
						31
9,400,000		9,179,945			529,070	32
2,025					64,954	33
3,513		35,435				34
					689	35
1,100,000		11,678,221				36
44,658					1,202,887	37
610,675					675,875	38
		500				39
11,160,871		20,894,101			2,473,475	40
87,443,808	12,036,297	53,239,654			57,581,646	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	Wyoming:					
3	Property	7,226,044		15,011,602	14,725,027	
4	Wind generation tax			1,390,284		
5	Unemployment	8,790		404,959	405,152	
6	Franchise	267,900		1,836,929	1,797,429	
7	Use	-181,803		1,107,801	770,777	
8	Annual Report			63,274	63,274	
9	Subtotal	7,320,931		19,814,849	17,761,659	
10						
11	State Other	2,075,266	83,375	-1,839,865	130,444	-25,103
12						
13	Miscellaneous:					
14	Goshute Possessory			22,367	22,367	
15	Sho-Ban Possessory			196,697	196,697	
16	Navajo Possessory	18,232		37,618	37,041	
17	Ute Possessory			31,353	31,353	
18	Crow Possessory			65,772	65,772	
19	Umatilla Possessory			63,409	63,409	
20	Subtotal	2,093,498	83,375	-1,422,649	547,083	-25,103
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	52,714,616	78,502,426	110,821,300	9,902,728	-276,749

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
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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
						2
7,512,619		14,650,964			360,638	3
1,390,284		1,390,284				4
8,597					404,959	5
307,400		1,836,929				6
155,221					1,107,801	7
		63,274				8
9,374,121		17,941,451			1,873,398	9
						10
46,685		-1,839,865				11
						12
						13
		22,367				14
		196,697				15
18,809		37,618				16
		31,353				17
		65,772				18
		63,409				19
65,494		-1,422,649				20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
87,443,808	12,036,297	53,239,654			57,581,646	41

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

$(147,313) Account 237, Interest accrued (1)
244,300 Account 123.1, Investment in subsidiary companies (2)
$ 96,987

(1) Represents interest on uncertain tax positions and corrections reclassified from Account 165, Prepayments, to Account 237.
(2) Represents the transfer of PacifiCorp Environmental Remediation Company's ("PERCo") taxes accrued balance as of June 30, 2012 from Account 123.1 due to the dissolution of PERCo on July 1, 2012.

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

Account 409.2, Income tax, other income and deductions, which represents federal income tax applicable to other income and deductions.

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: l

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

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

$3,471,014 Account 151, Fuel stock
483 Account 426.3, Penalties
$3,471,497

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

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

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

$110,219 Account 408.2, Taxes other than income taxes, other income and deductions
1,569 Account 589, Rents
16,646 Account 107, Construction work in progress
$128,434

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: l

Account 409.2, Income tax, other income and deductions, 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

$ 633 Account 408.2, Taxes other than income taxes, other income and deductions
66,796 Account 107, Construction work in progress
$67,429

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

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

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

$ 1,301 Account 408.2, Taxes other than income taxes, other income and deductions
153,964 Account 107, Construction work in progress
$155,265

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

Represents the transfer of PERCo's taxes accrued balance as of June 30, 2012 from Account 123.1, Investment in subsidiary companies, due to the dissolution of PERCo on July 1, 2012.

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

Account 409.2, Income tax, other income and deductions, 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: l

Account 409.2, Income tax, other income and deductions, 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: l

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

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

$ 11,129 Account 408.2, Taxes other than income taxes, other income and deductions
167,547 Account 589, Rents
606,911 Account 107, Construction work in progress
$785,587

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

Represents the transfer of PERCo's taxes accrued balance as of June 30, 2012 from Account 123.1, Investment in subsidiary companies, due to the dissolution of PERCo on July 1, 2012.

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

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

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

Represents the transfer of PERCo's taxes accrued balance as of June 30, 2012 from Account 123.1, Investment in subsidiary companies, due to the dissolution of PERCo on July 1, 2012.

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

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

Schedule Page: 262.1 Line No.: 15 Column: f

Represents the transfer of PERCo's taxes accrued balance as of June 30, 2012 from Account 123.1, Investment in subsidiary companies, due to the dissolution of PERCo on July 1, 2012.

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.: 18 Column: l

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

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

$ 30,763 Account 408.2, Taxes other than income taxes, other income and deductions
547 Account 589, Rents
4,554,955 Account 107, Construction work in progress

1,945,468 Account 151, Fuel stock
$6,531,733

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

$(6,611) Account 123.1, Investment in subsidiary companies (1)
6,474 Account 456, Other electric revenues (2)
$ (137)

(1) Represents the transfer of PERCo's taxes accrued balance as of June 30, 2012 from Account 123.1 due to the dissolution of PERCo on July 1, 2012.
(2) Represents the transfer of the refund from the Utah withholding tax to Account 456.

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

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

Schedule Page: 262.1 Line No.: 25 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.: 32 Column: l

$134,190 Account 408.2, Taxes other than income taxes, other income and deductions
3,181 Account 589, Rents
391,699 Account 107, Construction work in progress
$529,070

Schedule Page: 262.1 Line No.: 33 Column: l

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

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

Account 151, Fuel stock

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

Account 151, Fuel stock

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

Charged to same account as related goods.

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

$ 953 Account 408.2, Taxes other than income taxes, other income and deductions
9,694 Account 589, Rents
349,991 Account 107, Construction work in progress
$360,638

Schedule Page: 262.2 Line No.: 5 Column: l

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

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

Charged to same account as related goods.

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

Represents interest on uncertain tax positions and corrections reclassified from Account 165, Prepayments, to Account 237, Interest accrued.

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

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	33,383,365			411.4	1,808,768	
6	10%	4,045,318			420	1,624,396	
7	Idaho	581,585			411.4	42,532	-203,555
8	TOTAL	38,010,268				3,475,696	-203,555
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13	10%						
14							
15	Total Nonutility						
16							
17							
18							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
31,574,597	48.37		5
2,420,922	30		6
335,498	30		7
34,331,017			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
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			45
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			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

Schedule Page: 266 Line No.: 7 Column: g

Represents an adjustment to the prior year balance that was credited to Account 420, Investment Tax Credits.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Working Capital Deposits	5,073,136			924,798	5,997,934
2						
3	Reclamation Costs - Trapper Mine	5,008,644			250,104	5,258,748
4						
5	Reclamation Costs - Deseret Mine	517,386	232	49,200	7,820	476,006
6						
7	Reclamation Costs - Trail					
8	Mountain Mine	1,084,678	230	1,084,678		
9						
10	Western Coal Carriers Benefits					
11	Obligation	10,216,000	131	844,413	1,705,413	11,077,000
12						
13	Bank Card Incentives (5)		921	137,817	472,516	334,699
14						
15	Deferred Revenue - Other (5)	55,000	421	30,000		25,000
16						
17	Deferred Compensation Plan	9,369,229	131,232,241	1,853,131	684,207	8,200,305
18						
19	Redding Contract (20)	2,200,084	456	549,996		1,650,088
20						
21	Foote Creek Contract (15)	430,022	456	137,640		292,382
22						
23	Environmental Liabilities	12,604,395		2,672,828	16,837,518	26,769,085
24						
25	Unearned Joint Use Pole					
26	Contact (1)	3,664,410	454	7,249,716	6,284,361	2,699,055
27						
28	Misc. Security Deposits	13,681	172	11,056	250	2,875
29						
30	Lease Incentives (10)	76,247	931	48,157		28,090
31						
32	Cowlitz/Lewis River O&M (1)	112,124	539	273,242	276,203	115,085
33						
34	Employee Housing Security Deposits	14,975	131	800	1,600	15,775
35						
36	Oregon DSM Loans NPV Unearned					
37	Income (10)	117,459	456	101,725		15,734
38						
39	Cogeneration Bonds-Sunnyside	413,417				413,417
40						
41	Transmission Security Deposits	1,450,000	232,107	4,547,257	3,764,500	667,243
42						
43	Transmission Service Deposits	1,468,125	232,456	888,485	273,795	853,435
44						
45	MCI F.O.G. wire lease (1)	558,811	454	3,349,883	3,349,286	558,214
46						
47	TOTAL	220,954,063		44,110,070	156,183,542	333,027,535

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Unamortized contract values	166,506,240	242	20,280,046		146,226,194
2						
3	Loss contingency accrual				120,260,000	120,260,000
4						
5	Accrued Right-of-Way Obligations				1,091,171	1,091,171
6						
7						
8						
9						
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15						
16						
17						
18						
19						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	220,954,063		44,110,070	156,183,542	333,027,535

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

Account 131, Cash
Account 232, Accounts payable
Account 426.5, Other deductions

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	164,676,925	44,045,122	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	164,676,925	44,045,122	
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)	164,676,925	44,045,122	
18	Classification of TOTAL			
19	Federal Income Tax	144,976,964	38,776,096	
20	State Income Tax	19,699,961	5,269,026	
21	Local Income Tax			

NOTES

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
						208,722,047	4
							5
							6
							7
						208,722,047	8
							9
							10
							11
							12
							13
							14
							15
							16
						208,722,047	17
							18
						183,753,060	19
						24,968,987	20
							21

NOTES (Continued)

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	3,505,053,651	607,024,609	322,537,869
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	3,505,053,651	607,024,609	322,537,869
6	Nonutility			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	3,505,053,651	607,024,609	322,537,869
10	Classification of TOTAL			
11	Federal Income Tax	3,085,751,299	531,715,511	284,081,357
12	State Income Tax	419,302,352	75,309,098	38,456,512
13	Local Income Tax			

NOTES

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
		123.1	81,976	182.3	7,366,865	3,796,825,280	2
							3
							4
			81,976		7,366,865	3,796,825,280	5
							6
							7
							8
			81,976		7,366,865	3,796,825,280	9
							10
			72,170		6,485,582	3,339,798,865	11
			9,806		881,283	457,026,415	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	714,741,585	48,834,143	40,063,783
4				
5				
6	Other	31,980,155	2,583,924	1,689,764
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	746,721,740	51,418,067	41,753,547
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)	746,721,740	51,418,067	41,753,547
20	Classification of TOTAL			
21	Federal Income Tax	657,392,955	45,267,030	36,758,652
22	State Income Tax	89,328,785	6,151,037	4,994,895
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
7,856,386	69,998,994	182.3	3,111,482		37,451,735	695,709,590	3
							4
							5
	815,963			190	293,220	32,351,572	6
							7
							8
7,856,386	70,814,957		3,111,482		37,744,955	728,061,162	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
7,856,386	70,814,957		3,111,482		37,744,955	728,061,162	19
							20
6,916,542	62,343,510		2,739,262		33,229,604	640,964,707	21
939,844	8,471,447		372,220		4,515,351	87,096,455	22
							23

NOTES (Continued)

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

Account 182.3, Other regulatory assets
Account 190, Accumulated deferred income taxes

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

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Investment Tax Credit Regulatory Liability	18,331,373	190	1,124,468		17,206,905
2	Income Tax Reg. Liab. - WA Flow Through	3,344,410			441,249	3,785,659
3	Gain on Sale of Assets - OR (1)	40,409		246,635	241,387	35,161
4	Injuries & Damage Reserve - OR	186,354	925	801,168		-614,814
5	Property Insurance Reserve - OR	2,971,700	924	11,356,804	5,277,348	-3,107,756
6	Property Insurance Reserve - ID	88,212			113,544	201,756
7	Property Insurance Reserve - UT	(683,323)	924	921,282	2,152,236	547,631
8	Property Insurance Reserve - WY	271,761			349,810	621,571
9	SMUD Revenue Imputation (11)	6,782,142	440,442	2,679,837	12,555	4,114,860
10	Utah Home Energy Lifeline	60,539	142	32,973	423,063	450,629
11	BPA Balancing Account - WA	1,735,663	440,442	669,786		1,065,877
12	BPA Balancing Account - OR	2,698,057	440,442	905,356		1,792,701
13	Asset Retirement Obligations Reg. Difference	12,170,694			88,643	12,259,337
14	Washington Low Income Program	466,652	142	305,814	640,013	800,851
15	Misc. Regulatory Liabilities - OR	192,573			90,182	282,755
16	Blue Sky - OR	1,780,412	440,442	907,013	1,765,698	2,639,097
17	Blue Sky - WA	109,872	440,442	54,198	158,070	213,744
18	Blue Sky - CA	56,912	440,442	27,628	67,792	97,076
19	Blue Sky - UT	1,748,287	440,442	1,617,518	2,594,220	2,724,989
20	Blue Sky - ID	16,480	440,442	15,503	54,602	55,579
21	Blue Sky - WY	142,834	440,442	124,143	210,713	229,404
22	OR Energy Conservation Charge	2,324,196		24,562,034	24,557,087	2,319,249
23	Renewable Energy Credit Sales Deferral	43,842,950	456	33,284,995	7,032,278	17,590,233
24	Tax Revenue Requirement Adj. - UT	61,696				61,696
25	2010 Protocol Deferral - OR (1)	2,431,626		2,229,485	19,936	222,077
26	Powerdale Decommissioning Costs Giveback - UT (2)	540,834		360,556		180,278
27	Green House Gas Allowance Revenues - CA				2,434,345	2,434,345
28	2012 GRC Invest. in Emission Control Equip. - OR				17,000,000	17,000,000
29	Regulatory Liability - Reclassifications	9,545,204			7,981,448	17,526,652
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	111,258,519		82,227,196	73,706,219	102,737,542

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

Weighted average life is 47 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

Schedule Page: 278 Line No.: 22 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.: 25 Column: c

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

Schedule Page: 278 Line No.: 26 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.: 28 Column: a

Represents a one-time credit to be provided to Oregon customers in 2013 as a result of the 2012 Oregon general rate case outcome pertaining to PacifiCorp's investments in certain emissions control equipment at its coal-fueled generating facilities.

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

The following schedule summarizes regulatory liabilities reclassifications:

	As of December 31, 2012
Reclassified from Regulatory Liabilities to Regulatory Assets:	
Injuries & Damage Reserve - OR	$ 614,814
Property Insurance Reserve - OR	3,107,756
Reclassified from Regulatory Assets to Regulatory Liabilities:	
DSM Regulatory Asset - CA	765,482
DSM Regulatory Asset - UT	8,206,230
Alternative Rate For Energy (CARE) - CA	621,982
Deferred Excess Net Power Costs - WA Hydro	103,748
Deferred Excess RECs in Rates/RBA - UT 2012	2,753,648
RTO Grid West N/R - OR	6,035
Deferred Independent Evaluator Fee - UT	114,940
SB 408 Regulatory Asset - OR and MCBIT	10,904
Solar Feed-In Tariff Deferral - CA	354,070
Solar Incentive Program - UT	867,043
	$ 17,526,652

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	1,611,369,814	1,490,664,456
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,376,215,099	1,266,280,218
5	Large (or Ind.) (See Instr. 4)	1,247,618,388	1,136,708,521
6	(444) Public Street and Highway Lighting	19,998,454	20,409,578
7	(445) Other Sales to Public Authorities	16,263,330	19,305,829
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,271,465,085	3,933,368,602
11	(447) Sales for Resale	330,569,624	351,792,369
12	TOTAL Sales of Electricity	4,602,034,709	4,285,160,971
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	4,602,034,709	4,285,160,971
15	Other Operating Revenues		
16	(450) Forfeited Discounts	9,445,744	8,445,905
17	(451) Miscellaneous Service Revenues	6,413,143	6,203,507
18	(453) Sales of Water and Water Power	860	94,873
19	(454) Rent from Electric Property	18,875,927	20,180,422
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	136,299,293	160,005,183
22	(456.1) Revenues from Transmission of Electricity of Others	76,416,197	73,666,512
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	247,451,164	268,596,402
27	TOTAL Electric Operating Revenues	4,849,485,873	4,553,757,373

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
15,968,423	16,046,111	1,504,514	1,483,134	2
				3
16,828,774	16,489,191	211,986	221,634	4
21,316,760	21,228,737	33,553	33,695	5
142,675	144,334	3,636	3,745	6
292,709	398,493	3	12	7
				8
				9
54,549,341	54,306,866	1,753,692	1,742,220	10
11,869,789	10,766,697			11
66,419,130	65,073,563	1,753,692	1,742,220	12
				13
66,419,130	65,073,563	1,753,692	1,742,220	14

Line 12, column (b) includes $ 250,650,000 of unbilled revenues.

Line 12, column (d) includes 3,304,764 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

Account 451, Miscellaneous service revenues, includes the following items that were $250,000 or greater during the years ended December 31:

	2012	2011
Account service charges - disconnects/reconnects/returned check charges	$4,448,063	$4,155,399
Customer contract flat rate billings	1,907,528	1,981,186

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

Account 456, Other electric revenues, includes the following items that were $250,000 or greater during the years ended December 31:

	2012	2011
Renewable energy credit sales and amortization of deferrals, net of established deferrals	$ 106,970,144	$ 37,224,673
Wind-based ancillary services	12,186,449	8,045,284
Energy exchange credits	7,178,646	7,988,197
Steam sales	3,708,368	5,818,520
Flyash/by-product sales	3,234,313	3,135,065
Power sale and exchange agreements	1,091,292	1,091,292
Maintenance charges for work on transmission facilities	783,876	684,158
Revenue from generation interconnection and transmission service request studies	715,380	903,959
Phase shifting equipment fee from Western Electricity Coordinating Council	338,147	343,401
Service territory fixed cost recovery fee	262,676	-
Demand-side management revenue (1)	-	91,535,136
Blue Sky revenue (1)	-	2,482,644

(1) Beginning January 1, 2012, demand-side management revenue and Blue Sky revenue are included in Account 440, Residential sales; Account 442, Commercial and industrial sales; Account 444, Public street and highway lighting; and/or Account 445, Other sales to public authorities.

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	06LNX00311-LINE EXT 80% GTY		1,666			
4	06NETMT135-CA RES NET MTR	581	78,551	71	8,183	0.1352
5	06OALT015R-OUTD AR LGT SR	319	74,799	343	930	0.2345
6	06RESD000D-RES SRVC	180,463	23,742,090	18,153	9,941	0.1316
7	06RESDDL06-CA LOW INCOME	113,166	14,600,959	10,077	11,230	0.1290
8	06RGNSV025-CA SMALL GEN	334	63,843	136	2,456	0.1911
9	06RESD0DM9 - MULTI FAMILY	237	30,246	8	29,625	0.1276
10	06RESD0DS8-MULT FAM SBMET	1,370	146,538	15	91,333	0.1070
11	06RESD00DN-RES SVC-DEL NORT	89,992	11,726,283	7,310	12,311	0.1303
12	SMUD REVENUE IMPUTATIONS		44,051			
13	UNBILLED REVENUE	-140	89,000			-0.6357
14	UNBILLED REV - UNCOLLECTIBLE		1,000			
15	DSM - RESIDENTIAL		1,062,663			
16	BLUE SKY - RESIDENTIAL		25,660			
17	REVENUE - ACCOUNTING ADJ		31,141			
18	OTHER REV ADJ - DEFERRAL		-432,286			
19	OTHER REV ADJ - REALIZED		407,769			
20						
21	IDAHO					
22	07BLSKY01R-BLUESKY ENERGY		-1			
23	07LNX00010-MNTHLY 80%GUAR		1,269			
24	07LNX00035-ADV 80%MO GUAR		1,904			
25	07NETMT135-BPA-ID RES NET		-2,416			
26	07NETMT135-ID RES NET MTR	1,313	135,222	82	16,012	0.1030
27	07OALCO007-CUST OWN LIGHT	10	3,786	1	10,000	0.3786
28	07OALT07AR-SECURITY AR LG	96	39,144	121	793	0.4078
29	07OALT07AR-BPA-SECURITY AR		-180			
30	07RESD0001-RES SRVC	420,404	45,700,923	43,752	9,609	0.1087
31	07RESD0001-BPA-RES SRVC		-780,324			
32	07RESD0036-RES SRVC-OPTIO	255,948	23,285,776	14,097	18,156	0.0910
33	07RESD0036-BPA-RES SRVC-O		-463,776			
34	07RGNSV23A-ID SM GEN SVC	1,505	172,166	266	5,658	0.1144
35	07RGNSV23A-BPA-ID SM GEN SVC		-2,767			
36	SMUD REVENUE IMPUTATIONS		60,784			
37	BPA BALANCING ACCOUNT		-488,934			
38	UNBILLED REVENUE	-3,621	-64,000			0.0177
39	UNBILLED REV - UNCOLLECTIBLE		-2,000			
40	DSM - RESIDENTIAL		1,784,647			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	BLUE SKY - RESIDENTIAL		15,182			
2						
3	OREGON					
4	01COST0004 - 01RESD0004	5,112,560	296,056,922			0.0579
5	01COSTR023-RES GEN SRV CST	10,226	621,953			0.0608
6	01FXRENEWR-Fixed Renewable		-1			
7	01HABIT004 - 01RESD0004	39,782	2,258,005			0.0568
8	01HABTR023-RES GEN SVC HAB	13	836			0.0643
9	01LNX00102-LINE EXT 80% G		11,593			
10	01LNX00105-CNTRCT $ MIN G		8			
11	01LNX00109-REF/NREF ADV +		1,618			
12	01NETMT135-NET METERING		813,064	2,015		
13	01NETMT135-BPA-NET METERING		-60,684			
14	01NMTOU135-TOU NET MTR		6,904	14		
15	01NMTOU135-BPA-TOU NET MTR		-551			
16	01OALTB15R-OUTD AR LGT RE	2,400	400,909	2,737	877	0.1670
17	01OALTB15R-BPA-OUTD AR LGT		-9,253			
18	01PTOU0004 - 01RESD0004	18,662	1,112,957			0.0596
19	01RENEW004 - 01RESD0004	218,211	12,233,790			0.0561
20	01RENWR023-RENEW USAGE	35	2,171			0.0620
21	01RESD0004-RES SRVC		251,294,802	472,432		
22	01RESD0004-BPA-RES SRVC		-21,149,919			
23	01RESD004T-RES Time Option		828,849	1,247		
24	01RESD004T-BPA-RES Time Opt		-62,573			
25	01RGNSB023-SM GEN SVC-RES		842,064	2,479		
26	01RGNSB023-BPA-SM GEN SVC		-39,764			
27	01VIR04136-OR RES VOL INCTV		94,644	144		
28	01VIR04136-BPA-OR RES VOL		-7,001			
29	01ZZMERGCR-MERGER CREDITS		3			
30	OR GAIN ON SALE OF ASSET		121,591			
31	OR SB 838 RECOVERY		-2,199			
32	SMUD REVENUE IMPUTATIONS		557,876			
33	BPA BALANCING ACCOUNT		761,848			
34	UNBILLED REVENUE	3,687	1,612,000			0.4372
35	UNBILLED REV - UNCOLLECTIBLE		3,000			
36	DSM - RESIDENTIAL		13,939,319			
37	BLUE SKY - RESIDENTIAL		242,851			
38	REVENUE - ACCOUNTING ADJ		-6,159,864			
39	OTHER REV ADJ - DEFERRAL		-349,346			
40	OTHER REV ADJ - REALIZED		663,985			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	UTAH					
3	08BLSKY01R-BLUESKY ENERGY		-5			
4	08CFR00001-MTH FACILITY S		1,041			
5	08COOLKPRR - Utah Cool Keeper			103,667		
6	08LNX00001-MTHLY 80% GUAR		3,680			
7	08LNX00005-MTHLY MIN GUAR		2,983			
8	08LNX00013-80% MNTHLY MIN		22,938			
9	08LNX00108-ANN COST MTHLY		2,604			
10	08MHTP0006-MOBILE HOME &	10,668	746,320	7	1,524,000	0.0700
11	08MHTP0023-MOBILE HOME &	329	28,937	3	109,667	0.0880
12	08NETMT135-Net Metering	8,071	820,131	1,171	6,892	0.1016
13	08OALT007R-SECURITY AR LG	2,753	783,971	2,994	920	0.2848
14	08PTLD000R-POST TOP LIGHT	2	131	3	667	0.0655
15	08RESD0001-RES SRVC	6,418,576	640,419,931	682,151	9,409	0.0998
16	08RESD0002-RES SRVC-OPTIO	2,748	268,929	335	8,203	0.0979
17	08RESD0003-LIFELINE PRGRM	248,294	24,311,215	31,065	7,993	0.0979
18	08RESD0150-RES ALL E NOT5		-50			
19	08RGNSV006-GEN SRVC-RES	69,560	5,013,264	190	366,105	0.0721
20	08RGNSV023-GEN SRVC-RES	77,725	8,113,921	10,509	7,396	0.1044
21	08RGNSV06A-UT SM GEN SVC	5,185	409,870	19	272,895	0.0790
22	08RNM23135-UT NET MTR, GEN	257	24,941	16	16,063	0.0970
23	UNBILLED REVENUE	7,736	3,037,000			0.3926
24	UNBILLED REV - UNCOLLECTIBLE		-14,000			
25	DSM - RESIDENTIAL		18,864,721			
26	BLUE SKY - RESIDENTIAL		1,239,315			
27	REVENUE - ACCOUNTING ADJ		100,943			
28	REVENUE ADJ - DEFERRED NPC		-3,945,012			
29	OTHER REV ADJ - DEFERRAL		-360,127			
30	OTHER REV ADJ - REALIZED		30,721			
31						
32	WASHINGTON					
33	02BLSKY01R-BLUESKY ENERGY		-1			
34	02LNX00109-REF/NREF ADV +		807			
35	02NETMT135-WA RES NET MTR	813	73,345	54	15,056	0.0902
36	02NETMT135-BPA-WA RES NET		-3,334			
37	02OALTB15R-WA OUTD AR LGT	1,066	159,048	1,148	929	0.1492
38	02OALTB15R-BPA-WA OUTD AR		-4,354			
39	02RESD0016-WA RES SRVC	1,517,350	130,723,549	100,004	15,173	0.0862
40	02RESD0016-BPA-WA RES SRVC		-6,221,189			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	02RESD0017-BILL ASSISTANCE	62,672	5,372,522	4,074	15,383	0.0857
2	02RESD0017-BILL ASSISTANCE		-256,957			
3	02RESD0018-WA 3 PHASE RES	2,200	208,437	85	25,882	0.0947
4	02RESD0018-BPA-WA 3 PHASE		-9,022			
5	02RESD018X-WA 3 PHASE RES	426	39,661	18	23,667	0.0931
6	02RESD018X-BPA-WA 3 PHASE		-1,747			
7	02RFNDCENT-CENTRALIA RFND		1			
8	02RGNSB024-WA SM GEN SVC	2,409	284,327	558	4,317	0.1180
9	02RGNSB024-BPA-WA SM GEN		-9,878			
10	WASHINGTON-CHEHALIS		-1,320,000			
11	SMUD REVENUE IMPUTATIONS		165,843			
12	BPA BALANCING ACCOUNT		554,748			
13	UNBILLED REVENUE	9,339	898,000			0.0962
14	UNBILLED REV - UNCOLLECTIBLE		-6,000			
15	DSM - RESIDENTIAL		4,387,387			
16	REVENUE - ACCOUNTING ADJ		-4,387,387			
17	BLUE SKY - RESIDENTIAL		44,537			
18	REVENUE ADJ - DEFERRED NPC		-2,175,835			
19						
20	WYOMING					
21	05BLSKY01R-BLUESKY ENERGY		-2			
22	05LNX00102-LINE EXT 80% G		256			
23	05NETMT135-EXPERIMENTAL	1,251	133,418	111	11,270	0.1066
24	05NETMT135-EXPERIMENTAL	199	20,556	12	16,583	0.1033
25	05OALT015R-OUTD AR LGT SR	917	145,209	1,069	858	0.1584
26	05RESD0002-WY RES SRVC	914,432	91,179,438	98,451	9,288	0.0997
27	05RESD0002-WY RES SRVC	123,685	12,490,077	12,478	9,912	0.1010
28	05RGNSV025-WY SM GEN SVC	2,479	270,661	383	6,473	0.1092
29	05RGNSV025-WY SM GEN SVC	84	13,124	28	3,000	0.1562
30	05LNX00109-REF/NREF ADV +		890			
31	09OALT207R-SECURITY AR LG	77	23,016	92	837	0.2989
32	09RESD0002	-6	-443	4	-1,500	0.0738
33	09RFNDCENT-CENTRALIA RFND		2			
34	SMUD REVENUE IMPUTATIONS		75,922			
35	UNBILLED REVENUE	9,062	1,161,000			0.1281
36	UNBILLED REVENUE	511	81,000			0.1585
37	UNBILLED REV - UNCOLLECTIBLE		-17,000			
38	DSM - RESIDENTIAL		1,035,447			
39	DSM - RESIDENTIAL		135,819			
40	DSM - RESIDENTIAL GEN SVC		3,374			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	DSM - RESIDENTIAL GEN SVC		290			
2	BLUE SKY - RESIDENTIAL		92,194			
3	BLUE SKY - RESIDENTIAL		19,482			
4	REVENUE ADJ - DEFERRED NPC		-1,671,522			
5						
6	LESS MULTIPLE BILLINGS			-121,685		
7						
8	TOTAL RESIDENTIAL SALES	15,968,423	1,611,369,814	1,504,514	10,614	0.1009
9						
10	COMMERCIAL SALES					
11	CALIFORNIA					
12	06GNSV0025-CA GEN SRVC	55,923	8,700,280	6,779	8,249	0.1556
13	06GNSV025F-GEN SRVC-<20	943	161,136	85	11,094	0.1709
14	06GNSV0A32-GEN SRVC-20 KW	82,698	10,568,721	979	84,472	0.1278
15	06LGSV048T-LRG GEN SERV	61,135	5,310,167	13	4,702,692	0.0869
16	06LGSV0A36-LRG GEN SRVC-O	74,786	8,107,038	169	442,521	0.1084
17	06LNX00102-LINE EXT 80% G		12,625			
18	06LNX00103-LINE EXT 80% G		-1,018			
19	06LNX00105-CNTRCT $ MIN G		4,582			
20	06LNX00109-REF/NREF ADV +		72,874			
21	06LNX00300-80% MTHLY MIN GU		8,389			
22	06LNX00311-LINE EXT 80% GUAR		10,661			
23	06NMT36135-CA GEN SVC NET	366	47,906	1	366,000	0.1309
24	06OALT015N-OUTD AR LGT SR	712	169,816	515	1,383	0.2385
25	06RCFL0042-AIRWAY & ATHLE	185	34,266	38	4,868	0.1852
26	06NMT25135-GN SVC NET<20K	57	8,543	4	14,250	0.1499
27	06NMT32135-GN SVC NET>20K	421	59,471	5	84,200	0.1413
28	06LNX00110-REF/NREF ADV +		8,226			
29	SMUD REVENUE IMPUTATIONS		31,034			
30	UNBILLED REVENUE	-3,506	-405,000			0.1155
31	DSM - COMMERCIAL		684,411			
32	BLUE SKY - COMMERCIAL		1,869	10		
33	REVENUE - ACCOUNTING ADJ		19,145			
34	OTHER REV ADJ - DEFERRAL		-406,696			
35	OTHER REV ADJ - REALIZED		362,783			
36						
37	IDAHO					
38	07CISH0019-COMM & IND SPA	5,548	459,209	112	49,536	0.0828
39	07GNSV0006-GEN SRVC-LRG P	198,219	15,794,793	939	211,096	0.0797
40	07GNSV0009-GEN SRVC-HI VO	44,082	2,568,970	2	22,041,000	0.0583
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	07GNSV0023-GEN SRVC-SML P	133,815	12,605,805	6,433	20,801	0.0942
2	07GNSV0035-GEN SRVCOPTION	514	41,137	2	257,000	0.0800
3	07GNSV006A-GEN SRVC-LRG P	28,150	2,368,392	191	147,382	0.0841
4	07GNSV006A-BPA-GEN SRVC-LRG		-51,767			
5	07GNSV023A-GEN SRVC-SML P	20,621	1,984,378	1,342	15,366	0.0962
6	07GNSV023A-BPA-GEN SRVC-SML		-37,960			
7	07GNSV023F-GEN SRVC SML P	18	3,086	7	2,571	0.1714
8	07LNX00010-MNTHLY 80%GUAR		2,435			
9	07LNX00035-ADV 80%MO GUAR		258,986			
10	07LNX00040-ADV+REFCHG+80%		80,404			
11	07OALT007N-SECURITY AR LG	231	87,083	176	1,313	0.3770
12	07OALT07AN-SECURITY AR LG	11	4,367	12	917	0.3970
13	07OALT07AN-BPA-SECURITY AR		-20			
14	07LNX00312-ID LINE EXT		6,884			
15	07NMT06135-ID NET MTR-LG GEN	1,652	142,897	4	413,000	0.0865
16	07NMT23135-ID NET MTR-SM GEN	601	48,211	14	42,929	0.0802
17	07LNX00015-ANNUAL 80%GUAR		1,349			
18	07LNX00311-LINE EXT 80% GUAR		41,307			
19	07LNX00300-80% MTHLY MIN GU		9,162			
20	SMUD REVENUE IMPUTATIONS		36,916			
21	BPA BALANCING ACCOUNT		-30,696			
22	UNBILLED REVENUE	3,664	432,000			0.1179
23	DSM - COMMERCIAL		937,651			
24	BLUE SKY - COMMERCIAL		1,461	24		
25						
26	OREGON					
27	01COST0023-OR GEN SRV-COST	984,116	57,019,063			0.0579
28	01COST0048 - 01LGSV0048	845,831	44,523,226			0.0526
29	01COST023F-OR GEN SRV-COST	2,927	180,696			0.0617
30	01COSTB023-OR GEN SRV-COST	76,109	4,571,795			0.0601
31	01COSTL030-OR LG GEN SRV	1,005,511	53,767,532			0.0535
32	01COSTS028-OR GEN SERV-COST	1,914,253	111,073,925			0.0580
33	01GNSB0023-BPA DISC <30kW		-297,504			
34	01GNSB0023-BPA GEN SRV<30kW		5,326,746	12,813		
35	01GNSB0028-BPA GEN SRV>30kW		-500,569			
36	01GNSB0028-BPA GEN SRV>30kW		3,001,416	532		
37	01GNSB023T-BPA-OR GEN SRV		25,814	51		
38	01GNSB023T-BPA-OR GEN SRV		-1,686			
39	01GNSV0023-OR GEN SRV<30kW	-15	45,851,932	57,401		-3,056.7955
40	01GNSV0028-OR GEN SRV>30kW		44,743,588	8,793		
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	01GNSV023F-OR GEN SRV-FLAT	9,875	1,505,957	783	12,612	0.1525
2	01GNSV023M-OR GEN SRV-MANU	44	4,051	1	44,000	0.0921
3	01GNSV023T-OR GEN SRV-TOU		162,887	219		
4	01HABT0023-OR HABITAT BLEND	2,459	144,478			0.0588
5	01HABTB023-OR HABITAT BLEND	177	10,842			0.0613
6	01LGSB0030-GEN DEL SRV >200		-172,737			
7	01LGSB0030-GEN DEL SRV >200		800,530	25		
8	01LGSV0030-LG GEN SRV >1000		19,478,372	582		
9	01LGSV0048-1000kW AND OVR		9,420,201	98		
10	01LGSV048M-LRG GEN SRVC 1	60,473	3,534,592	1	60,473,000	0.0584
11	01LNX00100-LINE EXT 60% G		2,685			
12	01LNX00102-LINE EXT 80% G		278,561			
13	01LNX00103-LINE EXT 80% G		3,207			
14	01LNX00105-CNTRCT $ MIN G		14,263			
15	01LNX00109-REF/NREF ADV +		1,463,865			
16	01LNX00110-REF/NREF ADV +		1,500			
17	01LNX00120-LINE EXT 60% G		463			
18	01LNX00300-LINE EXT 80% GUAR		168,655			
19	01LNX00310-LINE EXT CONTRACT		807			
20	01LNX00311-LINE EXT 80% G		134,757			
21	01LPRS047M-PART REQ SRVC	37,762	3,181,372	3	12,587,333	0.0842
22	01NMT23135-NET MTR GEN <30		122,581	158		
23	01NMT23135-BPA-NET MTR GEN		-304			
24	01OALT015N-OUTD AR LGT NR	5,638	868,120	2,950	1,911	0.1540
25	01OALTB15N-OUTD AR LGT NR	1,558	266,977	1,120	1,391	0.1714
26	01OALTB15N-BPA OUTD AR LGT		-6,003			
27	01PTOU0023-OR GEN SRV-TOU	3,356	198,167			0.0590
28	01PTOUB023-OR GEN SRV-TOU	443	26,320			0.0594
29	01RCFL0054-REC FIELD LGT	1,170	122,795	102	11,471	0.1050
30	01RENW0023-OR RENW USAGE	8,262	489,096			0.0592
31	01RENWB023-OR RENEWABLE	372	22,950			0.0617
32	01STDAY023-DAY STD OFR SCH	2,458	135,392			0.0551
33	01STDAY028-DAY STD OFF SCH	13,198	710,897			0.0539
34	01STDAY030-STD DAY OFF SCH	4,503	229,573			0.0510
35	01VIR23136-VOL INCTV <=30 kW		52,077	40		
36	01VIR23136-BPA-VOL INCTV <=30		-211			
37	01VIR28136-VOL INCTV >30 kW		190,273	40		
38	01VIR28136-BPA-VOL INCTV >30		-4,059			
39	01VIR30136-VOL INCTV >200 kW		57,792	2		
40	01VIR48136-VOL INCTV >1000 kW		74,576	1		
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	01LGSB0048-LG GEN SVC >1000		-12,019			
2	01LGSB0048-LG GEN SVC >1000		51,988	1		
3	01NMT28135-NET MTR GEN >30		485,981	83		
4	01NMT28135-BPA-NET MTR GEN		-1,973			
5	01NMT30135-NET MTR GEN >200		555,955	16		
6	01NMT48135-NET MTR GEN		150,125	3		
7	01LGSV028M-LGSV <1000 kW	1,369	100,451	1	1,369,000	0.0734
8	01GNSV030M-GEN SRV 200 kW	1,750	129,817	1	1,750,000	0.0742
9	01GNSV0728-GEN SVC DIR ACC		337,512	18		
10	01GNSV0730-GEN SVC DIR ACC		4,339,075	44		
11	01GNSV0748-LG GEN SVC DIR		476,218	2		
12	OR GAIN ON SALE OF ASSET		88,789			
13	OR SB 838 RECOVERY		-1,852			
14	SMUD REVENUE IMPUTATIONS		496,407			
15	BPA BALANCING ACCOUNT		34,108			
16	UNBILLED REVENUE	-7,061	-1,769,000			0.2505
17	DSM - COMMERCIAL		9,186,357			
18	BLUE SKY - COMMERCIAL		489,409	263		
19	REVENUE - ACCOUNTING ADJ		-5,861,385			
20	OTHER REV ADJ - DEFERRAL		-297,896			
21	OTHER REV ADJ - REALIZED		639,906			
22						
23	UTAH					
24	08ABL-NRES - APPLICANT BUILT		-386			
25	08CFR00051-MTH FAC SRVCHG		38,771			
26	08CFR00052-ANN FAC SVCCHG		2			
27	08GNSV0006-GEN SRVC-DISTR	4,919,845	383,174,517	10,716	459,112	0.0779
28	08GNSV0009-GEN SRVC-HI VO	392,567	20,733,806	27	14,539,519	0.0528
29	08GNSV0023-GEN SRVC-DISTR	1,211,696	111,447,731	65,700	18,443	0.0920
30	08GNSV006A-GEN SRVC-ENERG	217,596	23,458,617	1,903	114,344	0.1078
31	08GNSV006B-GEN SRVC-DEM&	7,716	656,720	33	233,818	0.0851
32	08GNSV006M-MNL DIST VOLTG	3,007	193,416	6	501,167	0.0643
33	08GNSV009A-GEN SRVC HI VO	22,556	1,354,868	2	11,278,000	0.0601
34	08GNSV009M-MANL HIGH VOLT	122,825	5,993,706	1	122,825,000	0.0488
35	08GNSV023F-GEN SRVC FIXED	1,305	173,883	125	10,440	0.1332
36	08GNSV023M-GNSV DIST VOLT	168	14,006	5	33,600	0.0834
37	08GNSV06AM-MNL ENERGY TOD	306	39,862	1	306,000	0.1303
38	08GNSV06MN-GNSV DIST VOLT	32,674	2,353,827	470	69,519	0.0720
39	08LNX00002-MTHLY 80% GUAR		407,684			
40	08LNX00004-ANNUAL 80%GUAR		23,196			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	08LNX00006-FIXD MTHLY MIN		4,668			
2	08LNX00008-ANNUALMIN GUAR		8,171			
3	08LNX00014-80% MIN MNTHLY		1,906,691			
4	08LNX00017-ADV/REF&80%ANN		612,542			
5	08LNX00158-ANNUALCOST MTH		32,666			
6	08LNX00300-LINE EXT 80% PLUS		133,021			
7	08LNX00310-IRR 80% ANNUAL MIN		43,065			
8	08LNX00312-UT IRG LINE EXT		3,963			
9	08NMT06135-UT NET MTR GEN	39,666	3,105,773	73	543,370	0.0783
10	08NMT08135-NET MTR GEN SVC	14,924	1,019,201	3	4,974,667	0.0683
11	08NMT23135-NET MTR GEN <25	1,985	189,106	104	19,087	0.0953
12	08NMT6A135-NET MTR GEN SVC	660	78,355	5	132,000	0.1187
13	08OALT007N-SECURITY AR LG	8,354	1,942,657	4,362	1,915	0.2325
14	08POLE0075-POLES W/LIGHT		161	2		
15	08PRSV031M-BKUP MNT&SUPPL	10,144	820,061	2	5,072,000	0.0808
16	08PTLD000N-POST TOP LIGHT	6	452	2	3,000	0.0753
17	08TOSS015F-TRAFFIC SIG NM	182	15,867	23	7,913	0.0872
18	08TOSS0015-TRAF & OTHER	1,842	189,783	782	2,355	0.1030
19	08MONL0015-MTR OUTDONIGHT	16,179	1,150,465	425	38,068	0.0711
20	08LNX00311-LINE EXT 80% GUAR		265,892			
21	08GNSV0008-GEN SVC TOU >1000	1,014,138	68,685,707	154	6,585,312	0.0677
22	08GNSV008M-GEN SVC TOU	31,800	2,325,389	5	6,360,000	0.0731
23	UNBILLED REVENUE	37,483	4,213,000			0.1124
24	DSM - COMMERCIAL		16,792,152			
25	BLUE SKY - COMMERCIAL		288,234	130		
26	REVENUE - ACCOUNTING ADJ		96,488			
27	REVENUE ADJ - DEFERRED NPC		-4,133,094			
28	OTHER REV ADJ - DEFERRAL		-250,383			
29	OTHER REV ADJ - REALIZED		22,686			
30						
31	WASHINGTON					
32	02GNSB0024-GEN SRVC DO	40,619	3,766,988	3,010	13,495	0.0927
33	02GNSB0024-BPA-GEN SRVC DO		-166,539			
34	02GNSB024F-GEN SRVC DOM/F	141	16,731	6	23,500	0.1187
35	02GNSB024F-BPA-GEN SRVC		-4			
36	02GNSB24FP-GEN SVC SEASON	1,138	160,625	87	13,080	0.1411
37	02GNSB24FP-BPA-GEN SVC SEAS		-4,664			
38	02GNSV0024-WA GEN SRVC	480,239	41,095,765	14,426	33,290	0.0856
39	02GNSV024F-WA GEN SRVC-FL	1,111	140,900	111	10,009	0.1268
40	02LGSB0036-LRG GEN SVC IRG	81,156	5,779,187	99	819,758	0.0712
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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1	02LGSB0036-BPA-LRG GENSVC		-332,740			
2	02LGSV0036-WA LRG GEN SRV	695,604	50,356,813	808	860,896	0.0724
3	02LGSV048T-LRG GEN SRVC 1	146,912	9,632,374	27	5,441,185	0.0656
4	02LNX00102-LINE EXT 80% G		-124,423			
5	02LNX00103-LINE EXT 80% G		23,433			
6	02LNX00105-CNTRCT $ MIN G		1,844			
7	02LNX00109-REF/NREF ADV +		-1,789			
8	02LNX00110-REF/NREF ADV +		7,640			
9	02LNX00112-YR INCURRED CH		652			
10	02LNX00300-LINE EXT 80% G		11,661			
11	02LNX00310-IRG 80% ANNUAL		-1,130			
12	02LNX00311-LINE EXT 80% GUAR		45,865			
13	02LNX00312-WA IRG LINE EXT		2,814			
14	02OALT015N-WA OUTD AR LGT	1,612	222,933	843	1,912	0.1383
15	02OALTB15N-WA OUTD AR LGT	588	87,470	518	1,135	0.1488
16	02OALTB15N-BPA-WA OUTD AR		-2,402			
17	02RCFL0054-WA REC FIELD L	286	25,950	29	9,862	0.0907
18	02NMT24135-Net metering WA	493	43,024	8	61,625	0.0873
19	02NMT24135-BPA-Net metering WA		-19			
20	02NMT36135-NET MTR LG SVC	101	11,252	1	101,000	0.1114
21	BPA BALANCING ACCOUNT		44,992			
22	SMUD REVENUE IMPUTATIONS		144,750			
23	WASHINGTON - CHEHALIS		-1,020,000			
24	UNBILLED REVENUE	-2,524	-170,000			0.0674
25	DSM - COMMERCIAL		3,608,078			
26	BLUE SKY - COMMERCIAL		9,614	4		
27	REVENUE ADJ - DEFERRED NPC		-1,681,199			
28	REVENUE - ACCOUNTING ADJ		-3,608,078			
29						
30	WYOMING					
31	05GNSV0025-WY GEN SRVC	227,445	20,648,775	17,907	12,701	0.0908
32	05GNSV0025-WY GEN SRVC	33,984	2,989,773	2,350	14,461	0.0880
33	05GNSV0028-GEN SVC >15 kW	896,386	70,629,077	3,365	266,385	0.0788
34	05GNSV0028-GEN SVC >15 kW	106,904	8,309,982	431	248,037	0.0777
35	05GNSV025F-GEN SRVC-FL RA	999	182,283	182	5,489	0.1825
36	05GNSV025F-GEN SRVC-FL RA	195	22,761	32	6,094	0.1167
37	05LGSV0046-WY LRG GEN SRV	263,942	16,487,623	19	13,891,684	0.0625
38	05LGSV048T-LRG GENSRV TIM	10,122	702,133	1	10,122,000	0.0694
39	05LNX00100-LINE EXT 60% G		11,081			
40	05LNX00102-LINE EXT 80% G		572,603			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
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1	05LNX00102-LINE EXT 80% G		10,738			
2	05LNX00103-LINE EXT 80% G		1,646			
3	05LNX00105-CNTRCT $ MIN G		5,368			
4	05LNX00109-REF/NREF ADV +		688,657			
5	05LNX00109-REF/NREF ADV +		217,862			
6	05LNX00110-REF/NREF ADV +		559			
7	05LNX00110-REF/NREF ADV +		3,300			
8	05LNX00114-TEMP SVC 12MO>		3,578			
9	05LNX00114-TEMP SVC 12MO>		227			
10	05NMT25135-NET MTR GEN <25	269	23,067	17	15,824	0.0858
11	05NMT25135-NET MTR GEN <25	21	1,952	2	10,500	0.0930
12	05NMT28135-NET MTR SM GEN	5,177	470,963	13	398,231	0.0910
13	05NMT28135-NET MTR SM GEN	525	43,531	3	175,000	0.0829
14	05OALT015N-OUTD AR LGT SR	2,830	454,280	1,725	1,641	0.1605
15	05OALT015N-OUTD AR LGT SR	2	487	2	1,000	0.2435
16	05RCFL0054-WY REC FIELD L	713	58,863	51	13,980	0.0826
17	05LNX00300-LINE EXT 80% GUAR		60,157			
18	05LNX00311-LINE EXT 80% GUAR		87,823			
19	05GNS28025-GEN SVC	-3	-208			0.0693
20	05GNSV028M-GEN SVC >15 kW	1,219	93,135	1	1,219,000	0.0764
21	09GNSV0025-GEN SVC-SINGLE	-22	-1,777			0.0808
22	09OALT207N-SECURITY AR LG	275	71,487	139	1,978	0.2600
23	09MONL0213-WY MTR OUTDOOR	44	2,733	4	11,000	0.0621
24	05LNX00300-LINE EXT 80% GUAR		2,029			
25	05LNX00311-LINE EXT 80% GUAR		743			
26	09RFNDCENT-CENTRALIA RFND		2			
27	SMUD REVENUE IMPUTATIONS		110,121			
28	UNBILLED REVENUE	3,519	321,000			0.0912
29	UNBILLED REVENUE	29,744	2,566,000			0.0863
30	DSM - SMALL COMMERCIAL		742,332			
31	DSM - SMALL COMMERCIAL		90,930			
32	DSM - LARGE COMMERCIAL		190,705			
33	BLUE SKY - COMMERCIAL		4,941	42		
34	BLUE SKY - COMMERCIAL		1,202	14		
35	REVENUE ADJ - DEFERRED NPC		-2,392,691			
36						
37	LESS MULTIPLE BILLINGS			-23,355		
38						
39	TOTAL COMMERCIAL SALES	16,828,774	1,376,215,099	211,986	79,386	0.0818
40						
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	INDUSTRIAL SALES					
2	CALIFORNIA					
3	06GNSV0025-CA GEN SRVC	684	109,064	92	7,435	0.1595
4	06GNSV0A32-GEN SRVC-20 kW	2,198	324,972	26	84,538	0.1478
5	06LGSV048T-LRG GEN SERV	14,543	1,418,727	5	2,908,600	0.0976
6	06LGSV0A36-LRG GEN SRVC-O	4,624	546,463	11	420,364	0.1182
7	SMUD REVENUE IMPUTATIONS		4,580			
8	UNBILLED REVENUE	489	81,000			0.1656
9	DSM - INDUSTRIAL		84,434			
10	BLUE SKY - INDUSTRIAL		83			
11	OTHER REV ADJ - DEFERRAL		-26,751			
12	OTHER REV ADJ - REALIZED		23,893			
13	REVENUE - ACCOUNTING ADJ		8,216			
14						
15	IDAHO					
16	07CFR00001-MTH FACILITY S		2,217			
17	07CISH0019-COMM & IND SPA	123	10,529	3	41,000	0.0856
18	07GNSV0006-GEN SRVC-LRG P	88,451	6,102,815	107	826,645	0.0690
19	07GNSV0009-GEN SRVC-HI VO	79,529	4,775,393	13	6,117,615	0.0600
20	07GNSV0023-GEN SRVC-SML P	11,963	1,092,590	345	34,675	0.0913
21	07GNSV0035-GEN SRVCOPTION	669	50,660	1	669,000	0.0757
22	07GNSV006A-GEN SRVC-LRG P	4,197	355,552	28	149,893	0.0847
23	07GNSV006A-BPA-GEN SRVC-LRG		-7,722			
24	07GNSV023A-GEN SRVC-SML P	2,191	228,829	226	9,695	0.1044
25	07GNSV023A-BPA-GEN SRVC-SML		-4,033			
26	07GNSV023S-IDAHO TRAFFIC	8	1,190	3	2,667	0.1488
27	07LNX00035-ADV 80%MO GUAR		2,119			
28	07LNX00108-ANN COST MTHLY		1,996			
29	07OALT007N-SECURITY AR LG	13	5,084	17	765	0.3911
30	07OALT07AN-SECURITY AR LG		235	1		
31	07OALT07AN-BPA-SECURITY AR		-1			
32	07SPCL0001	1,396,100	73,155,283	1	1,396,100,000	0.0524
33	07SPCL0002	106,739	5,536,230	1	106,739,000	0.0519
34	SMUD REVENUE IMPUTATIONS		145,404			
35	BPA BALANCING ACCOUNT		-4,501			
36	UNBILLED REVENUE	-7,106	479,000			-0.0674
37	DSM - INDUSTRIAL		330,511			
38						
39	OREGON					
40	01COST0023-GEN SRV CST BSD	20,987	1,221,397			0.0582
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	01COST0048 - 01LGSV0048	1,688,428	87,874,870			0.0520
2	01COST023F-GEN SRV CST BSD	1	64			0.0640
3	01COSTB023-GEN SRV CST BSD	343	20,791			0.0606
4	01COSTL030-LG GEN SRV CST	213,225	11,446,447			0.0537
5	01COSTS028-GEN SRV COST >30	90,352	5,224,877			0.0578
6	01GNSB0023-BPA DISC <30 kW		-1,333			
7	01GNSB0023-GEN SRV BPA <30		26,391	59		
8	01GNSB0028-GEN SRV BPA >30		-2,360			
9	01GNSB0028-GEN SRV BPA >30		21,106	6		
10	01GNSV0023-OR GEN SRV <30 kW		1,033,120	1,144		
11	01GNSV0028-OR GEN SRV >30 kW		2,797,617	461		
12	01GNSV023F-GEN SRV - FLAT	2	655	2	1,000	0.3275
13	01GNSV023M-GEN SRV MANUAL	22	7,144	1	22,000	0.3247
14	01GNSV023T-GEN SRV TOU Option		2,668	4		
15	01GNSV0748-LG GEN SVC DIR		1,474,599	2		
16	01HABT0023-OR HABITAT BLEND	8	476			0.0595
17	01LGSV0030-LG GEN SRV >1000		5,946,069	153		
18	01LGSV0048-1000kW AND OVR		16,136,355	95		
19	01LGSV048M-LRG GEN SRVC 1	94,465	6,658,782	4	23,616,250	0.0705
20	01LNX00102-LINE EXT 80% G		44,302			
21	01LNX00300-LINE EXT 80% GUAR		6,764			
22	01LPRS047M-PART REQ SRVC	17,954	1,527,781	2	8,977,000	0.0851
23	01NMT28135-NET MTR GEN >30		16,051	4		
24	01NMT30135-NET MTR GEN >200		20,044	1		
25	01OALT015N-OUTD AR LGT NR	301	45,382	135	2,230	0.1508
26	01OALTB15N-OR OUTD AR LGT	5	714	5	1,000	0.1428
27	01OALTB15N-BPA-OR OUTD AR		-17			
28	01PTOU0023-OR GEN SRV TOU	39	2,420			0.0621
29	01RENW0023-OR RENW USAGE	114	6,368			0.0559
30	01RENWB023-OR RENEWABLE	1	67			0.0670
31	01STDAY023-DAY STD OFR SCH	19	1,086			0.0572
32	01STDAY028-DAY STD OFF SCH	187	10,531			0.0563
33	01VIR23136-VOL INCTV <=30 kW		964	1		
34	01VIR30136-VOL INCTV >200 kW		23,801	1		
35	OR GAIN ON SALE OF ASSET		31,569			
36	OR SB 838 RECOVERY		-1,223			
37	SMUD REVENUE IMPUTATIONS		223,928			
38	BPA BALANCING ACCOUNT		265			
39	UNBILLED REVENUE	-3,795	-176,000			0.0464
40	DSM - INDUSTRIAL		819,513			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	BLUE SKY - INDUSTRIAL		174,495	25		
2	OTHER REV ADJ - DEFERRAL		-195,400			
3	OTHER REV ADJ - REALIZED		371,387			
4	REVENUE - ACCOUNTING ADJ		-2,485,626			
5						
6	UTAH					
7	08CFR00051-MTH FAC SRVCHG		14,723			
8	08EFOP0021-ELEC FURNACE O	2,298	216,120	2	1,149,000	0.0940
9	08EFOP021M-ELEC FURNACE O	1,484	162,496	3	494,667	0.1095
10	08GNSV0006-GEN SRVC-DISTR	673,345	55,264,840	1,130	595,881	0.0821
11	08GNSV0009-GEN SRVC-HI VO	2,977,464	150,568,143	111	26,824,000	0.0506
12	08GNSV0023-GEN SRVC-DISTR	56,790	5,311,761	3,436	16,528	0.0935
13	08GNSV006A-GEN SRVC-ENERG	60,752	6,866,481	260	233,662	0.1130
14	08GNSV006B-GEN SRVC-DEM&	5,599	426,339	6	933,167	0.0761
15	08GNSV009A-GEN SRVC HI VO	18,355	1,386,133	6	3,059,167	0.0755
16	08GNSV009M-MANL HIGH VOLT	802,449	38,348,879	10	80,244,900	0.0478
17	08GNSV023F-GEN SRVC FIXED	4	2,409	1	4,000	0.6023
18	08GNSV06MN-GNSV DIST VOLT	1,161	99,255	26	44,654	0.0855
19	08GNSV09AM-MAN TOD HIVOLT	1,372	128,160	1	1,372,000	0.0934
20	08LNX00002-MTHLY 80% GUAR		162,757			
21	08LNX00004-ANNUAL 80%GUAR		6,031			
22	08LNX00014-80% MIN MNTHLY		20,100			
23	08LNX00017-ADV/REF&80%ANN		2,284			
24	08LNX00311-LINE EXT 80% GUAR		2,552			
25	08LNX00300-LINE EXT 80% PLUS		38,641			
26	08LNX00310-IRR 80% ANNUAL MIN		6,356			
27	08OALT007N-SECURITY AR LG	1,239	270,391	482	2,571	0.2182
28	08TOSS0015-TRAF & OTHER S	20	2,199	11	1,818	0.1100
29	08MONL0015-MTR OUTDONIGHT	14	3,347	7	2,000	0.2391
30	08NMT06135-NET MTR GEN SVC	2,041	188,344	5	408,200	0.0923
31	08NMT23135-NET MTR GEN <25	48	4,077	2	24,000	0.0849
32	08PRSV031M-BKUP MNT&SUPPL	8,899	866,245	1	8,899,000	0.0973
33	08SPCL0001	565,835	26,175,000	1	565,835,000	0.0463
34	08SPCL0002	1,013,366	37,589,515	1	1,013,366,000	0.0371
35	08SPCL0003	1,139,836	48,922,487	1	1,139,836,000	0.0429
36	08SPCL0005	22,888	963,688			0.0421
37	08GNSV06AM-MNL ENERGY TOD	299	35,402	2	149,500	0.1184
38	08GNSV0008-GEN SVC TOU >1000	987,027	68,354,707	108	9,139,139	0.0693
39	08GNSV008M-GEN SVC TOU	61,538	4,286,737	7	8,791,143	0.0697
40	UNBILLED REVENUE	-49,134	-962,000			0.0196
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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1	DSM - INDUSTRIAL		7,711,490			
2	BLUE SKY - INDUSTRIAL		89,938	12		
3	REVENUE - ACCOUNTING ADJ		69,996			
4	REVENUE ADJ - DEFERRED NPC		-2,587,942			
5	OTHER REV ADJ - DEFERRAL		-312,268			
6	OTHER REV ADJ - REALIZED		31,271			
7						
8	WASHINGTON					
9	02GNSB0024-WA GEN SRVC DO	2,169	205,697	96	22,594	0.0948
10	02GNSB0024-BPA-WA GEN SRVC		-8,891			
11	02GNSB24FP-WA GEN SVC	4	2,328	1	4,000	0.5820
12	02GNSB24FP-BPA-WA GEN SVC		-15			
13	02GNSV0024-WA GEN SRVC	15,959	1,383,737	353	45,210	0.0867
14	02GNSV024F-WA GEN SRVC-FL	33	7,794	4	8,250	0.2362
15	02LGSV0036-WA LRG GEN SRV	107,706	8,094,316	114	944,789	0.0752
16	02LGSV048T-LRG GEN SRVC 1	679,303	39,389,889	32	21,228,219	0.0580
17	02OALT015N-WA OUTD AR LGT	122	15,783	42	2,905	0.1294
18	02OALTB15N-WA OUTD AR LGT	29	4,372	16	1,813	0.1508
19	02OALTB15N-BPA-WA OUTD AR		-121			
20	02PRSV47TM-LRG PART REQMT	1,923	302,650	1	1,923,000	0.1574
21	02LGSB0036-LRG GEN SVC IRG	3,001	370,150	24	125,042	0.1233
22	02LGSB0036-BPA-LRG GENSVC		-12,305			
23	WASHINGTON - CHEHALIS		-510,000			
24	SMUD REVENUE IMPUTATIONS		81,494			
25	BPA BALANCING ACCOUNT		2,215			
26	UNBILLED REVENUE	21,110	1,239,000			0.0587
27	DSM - INDUSTRIAL		1,611,692			
28	REVENUE ADJ - DEFERRED NPC		-840,365			
29	REVENUE - ACCOUNTING ADJ		-1,611,692			
30						
31	WYOMING					
32	05GNSV0025-WY GEN SRVC	22,515	1,859,239	1,124	20,031	0.0826
33	05GNSV0025-WY GEN SRVC	4,893	416,284	292	16,757	0.0851
34	05GNSV0028-GEN SVC >15 kW	271,460	18,557,362	476	570,294	0.0684
35	05GNSV0028-GEN SVC >15 kW	42,836	3,113,193	71	603,324	0.0727
36	05GNSV025F-GEN SRVC-FL RA	26	4,066	8	3,250	0.1564
37	05LGSV0046-WY LRG GEN SRV	1,667,804	99,503,539	56	29,782,214	0.0597
38	05LGSV0046-WY LRG GEN SRV	32,498	2,109,768	3	10,832,667	0.0649
39	05LGSV046M-WY LRG GEN SRV	118,456	6,810,735	2	59,228,000	0.0575
40	05LGSV048M-TOU>1000KW MAN	393,753	19,908,156	1	393,753,000	0.0506
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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1	05LGSV048T-LRG GENSRV TIM	1,366,401	72,468,118	10	136,640,100	0.0530
2	05LNX00100-LINE EXT 60% G		42,682			
3	05LNX00102-LINE EXT 80% G		213,474			
4	05LNX00105-CNTRCT $ MIN G		34,892			
5	05LNX00109-REF/NREF ADV +		218,126			
6	05LNX00109-REF/NREF ADV +		1,963,720			
7	05OALT015N-OUTD AR LGT SR	85	12,394	43	1,977	0.1458
8	05PRSV033M-PART SERV REQ	1,236,679	75,251,585	6	206,113,167	0.0608
9	05LNX00300-LINE EXT 80% GUAR		11,677			
10	05LNX00311-LINE EXT 80% GUAR		28,164			
11	05GNSV028M-GEN SVC >15 kW	5,954	410,338	4	1,488,500	0.0689
12	05LGSV048M-TOU>1000KW MAN	261,938	14,087,059	3	87,312,667	0.0538
13	05LGSV048T-LRG GENSRV TIM	1,276,261	71,006,734	12	106,355,083	0.0556
14	09GNSV0025-GEN SVC-SINGLE	-5	-388			0.0776
15	05PRSV033M-PART SERV REQ	118,949	6,953,188	3	39,649,667	0.0585
16	09OALT207N-SECURITY AR LG	5	1,078	3	1,667	0.2156
17	09RFNDCENT-CENTRALIA RFND		2			
18	SMUD REVENUE IMPUTATIONS		500,726			
19	UNBILLED REVENUE	21,670	1,630,000			0.0752
20	UNBILLED REVENUE	-23,911	42,000			-0.0018
21	DSM - SMALL INDUSTRIAL		155,554			
22	DSM - SMALL INDUSTRIAL		31,622			
23	DSM - LARGE INDUSTRIAL		516,277			
24	DSM - LARGE INDUSTRIAL		275,869			
25	BLUE SKY - INDUSTRIAL		6,312	1		
26	REVENUE ADJ - DEFERRED NPC		-11,214,783			
27						
28	LESS MULTIPLE BILLINGS			-1,007		
29						
30	TOTAL INDUSTRIAL SALES	19,832,688	1,122,586,536	10,411	1,904,974	0.0566
31						
32	IRRIGATION SALES					
33	CALIFORNIA					
34	06APSV0020-AG PMP SRVC	69,691	8,328,576	1,369	50,907	0.1195
35	06LGSV048T-LRG GEN SERV	1,750	175,950	1	1,750,000	0.1005
36	06NMT20135-AGRICULTURAL	175	20,471	1	175,000	0.1170
37	06LNX00103-LINE EXT 80% G		2,746			
38	06LNX00110-REF/NREF ADV +		39,298			
39	06LNX00310-IRG 80% ANNUAL MIN		1,858			
40	06LNX00312-CA IRG LINE EXT		1,780			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	06USBR0020-KLAM IRG ONPRJ	26,196	3,513,432	656	39,933	0.1341
2	06LNX00109-REF/NREF ADV +		333			
3	IRRIGATION DEMAND CHARGE		-3,800			
4	UNBILLED REVENUE	-36	-3,000			0.0833
5	DSM - IRRIGATION		152,794			
6	BLUE SKY - IRRIGATION		16			
7	REVENUE - ACCOUNTING ADJ		-46			
8	OTHER REV ADJ - DEFERRAL		-138,403			
9	OTHER REV ADJ - REALIZED		102,769			
10						
11	IDAHO					
12	07APSA010L-IRG & Pump BPA		-840,436			
13	07APSA010L-IRG & Pump Large	456,227	38,421,587	3,035	150,322	0.0842
14	07APSA010S-IRG & Pump BPA		-9,130			
15	07APSA010S-IRG & Pump Small	4,959	511,518	404	12,275	0.1031
16	07APSAL10X-IRG & PUMP-Large l	233,875	19,248,856	1,056	221,473	0.0823
17	07APSAS10X-IRG & PUMP-Small l	3,298	349,149	249	13,245	0.1059
18	07APSVCNLL-BPA-LRG LOAD		-31,882			
19	07APSVCNLL-LRG LOAD CANAL	18,015	1,371,881	70	257,357	0.0762
20	07APSVCNLS-BPA-SML LOAD		-76			
21	07APSVCNLS-SML LOAD CANAL	41	5,409	17	2,412	0.1319
22	07BPADEBIT-BPA ADJUST FEE		303,953			
23	07LNX00015-ANNUAL 80%GUAR		194			
24	07LNX00040-ADV+REFCHG+80%		174,581			
25	07LNX00311-LINE EXT 80% GUAR		296			
26	07LNX00312-ID LINE EXT		16,923			
27	07APSN010L-ID LG IRR & PUMP	2,645	245,796	35	75,571	0.0929
28	07APSN010L-BPA-ID LG IRR 3 PH		-4,868			
29	07APSN010S-IRR SM 3 PH	24	3,620	7	3,429	0.1508
30	07APSN010S-BPA-IRR SM 3 PH		-45			
31	07APSNS10X-IRR SM 3 PHASE	227	22,598	10	22,700	0.0996
32	07ZZMERGCR-MERGER CREDITS		-18			
33	BPA BALANCING ACCOUNT		-513,394			
34	UNBILLED REVENUE	8				
35	DSM - IRRIGATION		1,809,432			
36	BLUE SKY - IRRIGATION		23	1		
37						
38	OREGON					
39	01APSV0041-AG PMP SRVC		2,169,473	4,767		
40	01APSV0041-BPA-AG PMP SRVC		-174,499			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	01APSV041L-Pumping Serv >30 kW		3,164,186	1,055		
2	01APSV041L-BPA-Pumping Serv		-292,068			
3	01APSV041T-BPA-AGR PUMP SRV		-2,328			
4	01APSV041T-AGR PUMP SRV-TOU		31,097	59		
5	01APSV041X-AG PMP SRVC		58,021	176		
6	01APSV41XL-Pumping Serv no BPA		140,571	31		
7	01BPADEBIT-BPA ADJUST FEE		32,296			
8	01COST0041	125,514	6,976,694			0.0556
9	01COST0048 - 01LGSV0048	8,500	445,331			0.0524
10	01COSTS028-GEN SRV CST >30	330	19,302			0.0585
11	01GNSV0028-GEN SRV >30 kW		12,191	3		
12	01HABIT041-01APSV0041 AG PMP	5	286			0.0572
13	01LGSB0048-LG GEN SVC >1000		-32,895			
14	01LGSB0048-LG GEN SVC >1000		90,261	1		
15	01LNX00103-LINE EXT 80% G		38,987			
16	01LNX00109-REF/NREF ADV +		-23,235			
17	01LNX00110-REF/NREF ADV +		135,783			
18	01LNX00310-LINE EXTENSION		10,354			
19	01PTOU0041 - 01APSV0041 AG	635	34,025			0.0536
20	01RENEW041 - 01APSV0041 AG	131	7,324			0.0559
21	01SLX00005-KLAMATH FALLS		362,930			
22	01SLX00013-K FALLS IRG MI		9,049			
23	01SLX00014-K FALLS IRG MI		113			
24	01STDAY041-Daily Standard Offer	131	6,893			0.0526
25	01USBGV033-KLAMATH IRG TOU		-41			
26	01USBOF033-KLAMATH BASIN	44,259	3,029,511	597	74,136	0.0684
27	01USBOF033-BPA-KLAMATH		-161,570			
28	01USBON033-KLAMATH BASIN	51,380	3,400,208	1,325	38,777	0.0662
29	01USBON033-BPA-KLAMATH		-185,451			
30	01VIR33136-VOL INCTV USB	2,491	164,389	33	75,485	0.0660
31	01VIR33136-BPA-VOL INCTV USB		-9,068			
32	01VIR41136-VOL INCTV-AGRI		14,332	5		
33	01VIR41136-BPA-VOL INCTV-AG		-1,300			
34	01USBGV033-IRG TOU W/O BPA	2,111	103,608	9	234,556	0.0491
35	01LNX00312-OR IRG LINE EXT		14,524			
36	01NMT33135-NET MTR - PROJECT	49	3,237	2	24,500	0.0661
37	01NMT33135-BPA-NET MTR		-178			
38	01NMT41135-NETMTR AG PMP		2,577	4		
39	01NMT41135-BPA-NETMTR AG		-165			
40	OR GAIN ON SALE OF ASSET		3,206			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	OR SB 838 RECOVERY		-55			
2	BPA BALANCING ACCOUNT		109,382			
3	OR IRRIGATION - BPA ADJ		17,594			
4	IRRIGATION DEMAND CHARGE		-200			
5	UNBILLED REVENUE	-63	16,000			-0.2540
6	DSM - IRRIGATION		462,527			
7	BLUE SKY - IRRIGATION		257	4		
8	REVENUE - ACCOUNTING ADJ		-243,017			
9	OTHER REV - DEFERRAL		-6,951			
10	OTHER REV ADJ - REALIZED		13,212			
11						
12	UTAH					
13	08APSV0010-IRR & SOIL DRA	210,866	14,246,232	2,746	76,790	0.0676
14	08APSV10NS-Irg Soil Drain Pump N	33,078	2,070,249	169	195,728	0.0626
15	08LNX00002-MTHLY 80% GUAR		330			
16	08LNX00004-ANNUAL 80%GUAR		7,178			
17	08LNX00014-80% MIN MNTHLY		16,620			
18	08LNX00017-ADV/REF&80%ANN		166,897			
19	08LNX00310-IRR 80% ANNUAL MIN		12,525			
20	08LNX00312-UT IRG LINE EXT		9,004			
21	08NMT10135-UT IRR SOIL DRNG	30	2,193	1	30,000	0.0731
22	UNBILLED REVENUE	-8				
23	DSM - IRRIGATION		469,480			
24	BLUE SKY - IRRIGATION		31			
25	REVENUE - ACCOUNTING ADJ		2,106			
26	OTHER REV ADJ - DEFERRAL		-7,297			
27	OTHER REV ADJ - REALIZED		672			
28						
29	WASHINGTON					
30	02APSV0040-WA AG PMP SRVC	151,697	12,461,740	5,077	29,879	0.0821
31	02APSV0040-BPA-WA AG PMP		-621,963			
32	02APSV040X-WA AG PMP SRVC	5,128	417,905	180	28,489	0.0815
33	02BPADEBIT-BPA ADJUST FEE		25,280			
34	02LNX00103-LINE EXT 80% G		4,075			
35	02LNX00105-CNTRCT $ MIN G		81			
36	02LNX00109-REF/NREF ADV +		3,539			
37	02LNX00110-REF/NREF ADV +		146,400			
38	02LNX00310-IRG 80% ANNUAL MIN		1,704			
39	02LNX00311-LINE EXT 80% GUAR		1,022			
40	02LNX00312-WA IRG LINE EXT		23,753			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	WASHINGTON - CHEHALIS		-120,000			
2	IRRIGATION DEMAND CHARGE		-500			
3	BPA BALANCING ACCOUNT		67,966			
4	UNBILLED REVENUE	-144	18,000			-0.1250
5	DSM - IRRIGATION		455,453			
6	REVENUE - ACCOUNTING ADJ		-455,453			
7	BLUE SKY - IRRIGATION		46	2		
8						
9	WYOMING					
10	05APS00040-AG PUMPING SVC	26,014	1,913,730	650	40,022	0.0736
11	05APS00040-AG PUMPING SVC	41	3,066	1	41,000	0.0748
12	05LNX00110-REF/NREF ADV +		46,719			
13	05LNX00110-REF/NREF ADV +		18,809			
14	05LNX00103-LINE EXT 80% G		6,769			
15	05LNX00103-LINE EXT 80% G		1,664			
16	05LNX00310-LINE EXTENSION		442			
17	05LNX00312-WY IRG LINE EXT		3,341			
18	05LNX00312-WY IRG LINE EXT		-279			
19	09APSV0210-IRR & SOIL DRA	4,796	342,744	78	61,487	0.0715
20	UNBILLED REVENUE	6	2,000			0.3333
21	DSM - IRRIGATION		16,969			
22	DSM - IRRIGATION		3,148			
23	BLUE SKY - IRRIGATION		11			
24						
25	LESS MULTIPLE BILLINGS			-744		
26						
27	TOTAL IRRIGATION SALES	1,484,072	125,031,852	23,142	64,129	0.0842
28						
29	PUBLIC STREET & HWY LIGHTING					
30	CALIFORNIA					
31	06CUSL053F-SPECIAL CUST O	1,432	209,706	110	13,018	0.1464
32	06CUSL058F-CUST OWND STR	239	39,077	23	10,391	0.1635
33	06HPSV0051-HI PRESSURE SO	683	182,306	80	8,538	0.2669
34	UNBILLED REVENUE	-49	-9,000			0.1837
35	DSM REVENUE - PSHL		9,501			
36	OTHER REV ADJ - DEFERRAL		-5,324			
37	OTHER REV ADJ - REALIZED		4,528			
38	REVENUE - ACCOUNTING ADJ		-2			
39						
40	IDAHO					
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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1	07GNSV023S-IDAHO TRAFFIC	154	17,424	24	6,417	0.1131
2	07SLCO0011-STR LGT CO-OWN	70	31,339	30	2,333	0.4477
3	07SLCU012E-ENGY STR LGT	328	36,532	21	15,619	0.1114
4	07SLCU012F-FULL MNT STR	1,886	370,529	238	7,924	0.1965
5	07SLCU012P-PART MNT STR LGT	194	27,984	16	12,125	0.1442
6	UNBILLED REVENUE	17	2,000			0.1176
7	DSM REVENUE - PSHL		12,580			
8						
9	OREGON					
10	01COSL0052-STR LGT SRVC C	557	89,180	46	12,109	0.1601
11	01CUSL0053-CUS-OWNED MTRD	814	63,471	73	11,151	0.0780
12	01CUSL053E-STR LGT SVC	8,577	668,994	161	53,273	0.0780
13	01CUSL053F-STR LGT SRVC C	184	21,688	15	12,267	0.1179
14	01HPSV0051-HI PRESSURE SO	18,968	4,138,439	702	27,020	0.2182
15	01LEDSL055-LED PILOT ST LIGHT	18	4,848	11	1,636	0.2693
16	01MVSL0050-MERC VAPSTR LG	8,773	1,219,545	251	34,952	0.1390
17	01OALT015N-OUTD AR LGT NR	18	2,751	6	3,000	0.1528
18	01OALTB15N-OR OUTD AR LGT	2	414	2	1,000	0.2070
19	01OALTB15N-BPA-OR OUTD AR		-8			
20	OR GAIN ON SALE OF ASSET		1,480			
21	OR SB 838 RECOVERY		-11			
22	UNBILLED REVENUE	625	112,000			0.1792
23	DSM REVENUE - PSHL		154,319			
24	REVENUE - ACCOUNTING ADJ		-20,623			
25	OTHER REV ADJ - DEFERRAL		-1,695			
26	OTHER REV ADJ - REALIZED		-760,278			
27						
28	UTAH					
29	08CFR00012-STR LGTS (CONV		54			
30	08CFR00051-MTH FAC SRVCHG		4,529			
31	08CFR00062-STREET LIGHTS		79			
32	08OALT007N-SECURITY AR LG	25	6,007	13	1,923	0.2403
33	08TOSS015F-TRAFFIC SIG NM	1,159	98,192	123	9,423	0.0847
34	08SLCO0011-STR LGT CO-OWN	17,058	5,116,046	844	20,211	0.2999
35	08TOSS0015-TRAF & OTHER S	2,792	306,979	1,504	1,856	0.1099
36	08MONL0015-MTR OUTDONIGHT	686	57,280	56	12,250	0.0835
37	08SLCU012P-STR LGT CUST-O	5,328	670,359	231	23,065	0.1258
38	08SLCU012F-STR LGT CUST-O	1,792	248,853	103	17,398	0.1389
39	08SLCU012E-DECOR CUST-OWN	50,157	3,340,033	503	99,716	0.0666
40	08THIK0077-STR LIGHT SPEC	30	3,647	1	30,000	0.1216
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	UNBILLED REVENUE	-1,951	-255,000			0.1307
2	DSM REVENUE - PSHL		280,745			
3	REVENUE - ACCOUNTING ADJ		1,630			
4	OTHER REV ADJ - DEFERRAL		-7,815			
5	OTHER REV ADJ - REALIZED		829			
6						
7	WASHINGTON					
8	02CFR00012-STR LGTS (CONV		91			
9	02COSL0052-WA STR LGT SRV	264	44,471	16	16,500	0.1685
10	02CUSL053F-WA STR LGT SRV	3,490	250,920	117	29,829	0.0719
11	02CUSL053M-WA STR LGT SRV	1,184	84,114	104	11,385	0.0710
12	02HPSV0051-WA HI PRESSURE	3,381	672,635	157	21,535	0.1989
13	02MVSL0057-WA MERC VAPSTR	1,952	243,299	42	46,476	0.1246
14	WASHINGTON - CHEHALIS		-30,000			
15	UNBILLED REVENUE	-163	-2,000			0.0123
16	DSM REVENUE - PSHL		26,614			
17	REVENUE - ACCOUNTING ADJ		-26,614			
18						
19	WYOMING					
20	05COSL0057-CO-OWND STR LG	268	59,345	18	14,889	0.2214
21	05CUSL058M-CUST OWND STR	78	5,313	11	7,091	0.0681
22	05CUSL0E58-CUST OWND ST LT	1,057	71,740	30	35,233	0.0679
23	05CUSL0M58-CUST OWND ST LT	45	3,664	4	11,250	0.0814
24	05HPSV0051-HI PRESSURE SO	5,041	1,129,655	164	30,738	0.2241
25	05MVS00053-MERCURY VAPOR	3,798	519,270	260	14,608	0.1367
26	05OALT015N-OUTD AR LGT SR	1	111	1	1,000	0.1110
27	09MONL0213-WY MTR OUTDOOR	27	2,091	1	27,000	0.0774
28	09SLCO0211-STR LGT CO-OWN	1,420	401,009	48	29,583	0.2824
29	09SLCUP212-CUST OWND ST LT	77	11,213	9	8,556	0.1456
30	09TOSS0213-TRAFFIC & OTHER	68	2,660	14	4,857	0.0391
31	UNBILLED REVENUE	146	24,000			0.1644
32	UNBILLED REVENUE	-25	-9,000			0.3600
33	DSM REVENUE - PSHL		14,314			
34	DSM REVENUE - PSHL		3,398			
35						
36	LESS MULTIPLE BILLINGS			-2,547		
37						
38	TOTAL PUBLIC STREET & HWY	142,675	19,998,454	3,636	39,240	0.1402
39						
40	OTHER SALES TO PUBLIC AUTH					
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	UTAH					
2	08GNSV009M-MANL HIGH VOLT	255,203	13,315,246	2	127,601,500	0.0522
3	08PRSV031M-BKUP MNT&SUPPL	48,750	2,993,179	1	48,750,000	0.0614
4	UNBILLED REVENUE	-11,244	-459,000			0.0408
5	DSM REVENUE - OPSA		420,300			
6	REVENUE - ACCOUNTING ADJ		2,942			
7	OTHER REV ADJ - DEFERRAL		-9,812			
8	OTHER REV ADJ - REALIZED		475			
9						
10	TOTAL OTHER SALES TO PUBLIC	292,709	16,263,330	3	97,569,667	0.0556
11						
12	FORFEITED DISCOUNTS					
13	CALIFORNIA					
14	06LPAY0300-LATEFEE		336,161			
15						
16	IDAHO					
17	07LPAY0300-LATEFEE		485,995			
18						
19	OREGON					
20	01LPAY0300-LATEFEE		3,818,384			
21						
22	UTAH					
23	08LPAY0300-LATEFEE		3,437,324			
24						
25	WASHINGTON					
26	02LPAY0300-LATEFEE		677,733			
27						
28	WYOMING					
29	05LPAY0300-RES-LATEFEE		419,804			
30	05LPAY0300-COM-LATEFEE		145,270			
31	05LPAY0300-IND-LATEFEE		116,508			
32	05LPAY0300-Other-LATEFEE		8,565			
33						
34	TOTAL FORFEITED DISCOUNTS		9,445,744			
35						
36	MISCELLANEOUS SERVICE REV					
37	CALIFORNIA					
38	06CFR00003-MTH MAINTENANC		1,454			
39	06CONN0300-CA RECONNECTIO		33,315			
40	06FCBUYOUT		101,378			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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SALES OF ELECTRICITY BY RATE SCHEDULES

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1	06RCHK0300-CA RET CHK CHR		12,528			
2	06TAMP0300-CA TAMP & UNAU		1,650			
3	06TEMP0300-CA TEMP SRVC C		1,815			
4	06TRBL0300-CA TROUBLE CAL		30			
5	06XMTRTAMP-TAMPERING -		494			
6	HOME COMFORT		558			
7						
8	IDAHO					
9	07CFR00001-MTH FAC SRVCHG		1,682			
10	07CONN0300-ID RECONNECTIO		55,320			
11	07FCBUYOUT-FAC CHG BUYOUT		3,187			
12	07RCHK0300-ID RET CHK CHR		32,800			
13	07TAMP0300		825			
14	07TEMP0014-TEMP SRVC CONN		12,580			
15	07XMTRTAMP-TAMPERING -		83			
16	OTHER		83			
17						
18	OREGON					
19	01CFR00001-MTH FACILITY S		137,453			
20	01CFR00003-MTH MAINTENANC		25,964			
21	01CFR00004-EMRGNCY ST&BY		26,390			
22	01CFR00005-INTERMTNT SRVC		40,109			
23	01CFR00013-MTH MISC CHRG		2,284			
24	01CFR00014-YR MISC CHRG		5			
25	01CONN0300-RECONNECTION C		388,565			
26	01CONTSERV-3RD PRTY OUTSIDE		20,054			
27	01ESSC0600-ESS charges		7,782			
28	01FCBUYOUT-FAC CHG BUYOUT		501,161			
29	01DPAC0300-DEMAND PULSE		10,500			
30	01RCHK0300-RETURNED CHECK		292,620			
31	01TAMP0300-TAMP & UNAUTH		16,875			
32	01TEMP0300-TEMP SRVC CHRG		97,840			
33	01XMTRTAMP-TAMPERING -		3,547			
34	OTHER		-22,912			
35						
36	UTAH					
37	08CFR00013-MTH MISC CHRG		147,885			
38	08CFR00051-MTH FAC SRVCHG		90,237			
39	08CFR00052-ANN FAC SVCCHG		424			
40	08CFR00053-MTHLY MAINTFEE		10,984			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	08CFR00063-MTH MISC CHARG		2,386			
2	08CFR00064-ANN MISC CHARG		6,660			
3	08CONN0300-RECONN&DISCONN		466,810			
4	08CONTSERV-3RD PARTY O/S		274,310			
5	08FCBUYOUT-FAC CHG BUYOUT		277,713			
6	08MONL0015-MTR OUTDONIGHT		-22,500			
7	08INFO0300-CUST/3RD P REQ		40			
8	08NCON0300-UT FEE NRES RE		4,390			
9	08RCHK0300-UT RET CHK CHR		479,200			
10	08RCON0001-CONNECT FEE		1,562,681			
11	08TAMP0300-TAMPERING&UNAU		11,550			
12	08TEMP0014-TEMP SRVC CONN		421,385			
13	08XMTRTAMP-TAMPERING -		1,051			
14	08VISIT300-UT Visit Service Call		195,820			
15	MISC SERV - ACCT SERV CHRG		488			
16	ENERGY FINANSWER NEW COM		13,728			
17	OTHER		-68,885			
18						
19	WASHINGTON					
20	02CFR00003-MTH MAINTENANC		1,320			
21	02CFR00004-EMRGNCY ST&BY		5,815			
22	02CFR00005-INTERMTNT SRVC		4,291			
23	02CONN0300-WA RECONNECTIO		83,990			
24	02DPAC0300-DEMAND PULSE		2,205			
25	02FCBUYOUT - FAC CHG BUYOUT		9,737			
26	02RCHK0300-WA RET CHK CHR		56,340			
27	02TAMP0300-WA TAMP & UNAU		3,075			
28	02TEMP0300-WA TEMP SRVC C		15,645			
29	02XMTRTAMP-TAMPERING -		912			
30	HOME COMFORT		1,969			
31	ENERGY FINANSWER NEW COM		167			
32	OTHER		-24,147			
33						
34	WYOMING					
35	05CFR00003-MTH MAINTENANC		1,768			
36	05CFR00004-EMRGNCY ST&BY		18,610			
37	05CFR00005-INTERMTNT SRVC		10,049			
38	05CFR00013-MTH MISC CHRG		3,186			
39	05CONN0300-WY RECONNECTIO		83,830			
40	05FCBUYOUT-FAC CHG BUYOUT		240,716			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	05RCHK0300-WY RET CHK CHR		67,680			
2	05TAMP0300		600			
3	05TEMP0300-WY TEMP SRVC C		35,960			
4	05XMTRTAMP-TAMPERING -		188			
5	09CFR00005-INTERMTNT SRVC		339			
6	05CONN0300-WY RECONNECTIO		16,720			
7	05FCBUYOUT-FAC CHG BUYOUT		80,753			
8	05RCHK0300-WY RET CHK CHR		8,760			
9	05TAMP0300		150			
10	05TEMP0300-WY TEMP SRVC C		425			
11	09CFR00001-MTH FAC SRVCHG		5,067			
12	09CFR00014-YR MISC CHRG		3			
13	ENERGY FINANSWER 12,000		129			
14	OTHER		-7,485			
15						
16	TOTAL MISC SERVICE REV		6,413,143			
17						
18	SALES OF WATER AND WTR PWR					
19	UTAH		455			
20	WYOMING		405			
21						
22	TOTAL WATER AND WATER PWR		860			
23						
24	RENT FROM ELEC PROPERTIES					
25	INTERCOMPANY RENT REVENUE		115			
26						
27	CALIFORNIA					
28	06CFR00006-MTH RNTAL CHRG		1,709			
29	RENT REVENUE - HYDRO		1,245			
30	RENT REVENUE - SUBLEASES		17,411			
31	JOINT USE		501,882			
32						
33	IDAHO					
34	07CFR00009-YR LSE CHRG-EQ		739			
35	07INVCHG00-INVEST MNT CHG		180			
36	07POLE0075-STEEL POLES US		275			
37	RENT REV - TRANSMISSION		400			
38	RENT REV - DISTRIBUTION		300			
39	RENT REVENUE - HYDRO		74,792			
40	RENT REVENUE - SUBLEASES		2,216			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	JOINT USE		161,725			
2						
3	OREGON					
4	01CFR00006-MTH RNTAL CHRG		665,408			
5	RENTS - COMMON		497,198			
6	MCI FOGWIRE REVENUE		3,349,883			
7	RENT REVENUE - SUBLEASES		259,766			
8	RENT REV - TRANSMISSION		250,469			
9	RENT REV - DISTRIBUTION		57,814			
10	RENT REVENUE - HYDRO		22,455			
11	RENT REV - GEN(COMM)		52,775			
12	JOINT USE		3,519,023			
13						
14	UTAH					
15	08CFR00056-MTH EQUIP RENT		33			
16	08CFR00058-MTH EQUIP LEAS		679,523			
17	08INVCHG0N-INVEST MNT CHG		4,415			
18	08INVCHG0R-INVEST MNT CHG		244			
19	08POLE0075-STEEL POLES US		56,963			
20	RENTS - COMMON		1,736			
21	RENTS - NON COMMON		4,200			
22	RENT REVENUE - STEAM		111,624			
23	RENT REV - TRANSMISSION		1,067,789			
24	RENT REV - DISTRIBUTION		480,594			
25	RENT REVENUE - HYDRO		77,589			
26	RENT REV - GEN(COMM)		6,505			
27	RENT REVENUE - SUBLEASES		2,619,506			
28	JOINT USE		2,206,197			
29						
30	WASHINGTON					
31	02CFR00001-MTH FACILITY S		2,103			
32	02CFR00006-MTH RNTAL CHRG		24,836			
33	RENT REV - TRANSMISSION		16,765			
34	RENT REV - DISTRIBUTION		18,844			
35	RENT REVENUE - HYDRO		548,491			
36	RENT REV - GEN(COMM)		35,997			
37	RENT REVENUE - SUBLEASES		49,280			
38	JOINT USE		949,023			
39						
40	WYOMING					
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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1	05CFR00001-MTH FACILITY S		11,524			
2	05CFR00006-MTH RNTAL CHRG		2,481			
3	09POLE0075-STEEL POLES US		18,314			
4	RENT REVENUE - STEAM		4,925			
5	RENT REVENUE - STEAM		58,852			
6	RENT REV - TRANSMISSION		250			
7	RENT REV - DISTRIBUTION		150			
8	RENT REV - GEN(COMM)		20,430			
9	RENT REVENUE - SUBLEASES		18,199			
10	JOINT USE		340,703			
11	JOINT USE		62			
12						
13	TOTAL RENT FROM ELEC PROP		18,875,927			
14						
15	OTHER ELECTRIC REVENUE					
16	WIND BASED ANCILLARY SVC		12,186,449			
17	RENEWABLE ENERGY CREDIT		75,018,594			
18	RENEWABLE ENERGY CR AMORT		31,951,550			
19	NON-WHEELING SYSTEM		8,308,350			
20	OTHER ELECTRIC ESTIMATE		-293,811			
21	OTHER ELECTRIC (EXCL		-27,103			
22						
23	CALIFORNIA					
24	3RD PARTY TRANS O&M		32,890			
25	FISH, WILDLIFE, RECR		8,704			
26						
27	IDAHO					
28	3RD PARTY TRANS O&M		133,191			
29						
30	OREGON					
31	3RD PARTY TRANS O&M		335,406			
32	OTHER ELECTRIC DSR CARRY		111,851			
33	OTHER ELECTRIC (EXCL WHL		1,106,982			
34						
35	UTAH					
36	3RD PARTY TRANS O&M		221,497			
37	FISH, WILDLIFE, RECR		2,465			
38	FLYASH SALES		2,125,776			
39	M&S INVENTORY REVENUE		30,069			
40	ELECTRIC INCOME - OTHER		87,375			
41	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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						
2	WASHINGTON					
3	3RD PARTY TRANS O&M		-3,370			
4	FISH, WILDLIFE, RECR		5,190			
5	WA - COLSTRIP 3		-52,188			
6						
7	WYOMING					
8	3RD PARTY TRANS O&M		64,262			
9	FLYASH SALES		1,060,156			
10	FLYASH SALES		48,382			
11	WY-REGULATORY RECOVERY		262,676			
12	ELECTRIC INCOME - OTHER		13			
13						
14	TOTAL OTHER ELEC REVENUE		132,725,356			
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	TOTAL Billed	54,515,006	4,425,193,615	1,753,692	31,086	0.0812
42	Total Unbilled Rev.(See Instr. 6)	34,335	13,732,500	0	0	0.4000
43	TOTAL	54,549,341	4,438,926,115	1,753,692	31,105	0.0814

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Requirement Sales					
2	Brigham City Corporation	RQ	T-12	20	20	19
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	0.7	0.6
6	Navajo Tribal Util Auth (Mexican Hat)	RQ	T-6	0.2	0.2	0.1
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	12
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**

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
121,534	2,515,797	3,168,536		5,684,333	2
748	11,041	13,398		24,439	3
6,492	119,751	114,825		234,576	4
3,731	72,298	65,987		138,285	5
968	19,378	16,872		36,250	6
9,174	138,461	159,808		298,269	7
11,110		1,045,532		1,045,532	8
73,002	1,565,215	1,896,583		3,461,798	9
-2,772			-158,949	-158,949	10
					11
					12
29,298		756,389		756,389	13
57,191		930,998		930,998	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Actual Demand (MW) 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	SF	T-12	NA	NA	NA
5	Basin Electric Power Cooperative	SF	T-11	NA	NA	NA
6	Basin Electric Power Cooperative	SF	T-12	NA	NA	NA
7	Black Hills Power, Inc.	LF	441	50	54	48
8	Black Hills Power, Inc.	SF	T-12	NA	NA	NA
9	Bonneville Power Administration	LF	368	NA	NA	NA
10	Bonneville Power Administration	LF	T-11	NA	NA	NA
11	Bonneville Power Administration	LU	519	NA	NA	NA
12	Bonneville Power Administration	SF	T-11	NA	NA	NA
13	Bonneville Power Administration	SF	T-12	NA	NA	NA
14	Bonneville Power Administration	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
73			1,605	1,605	1
61,600		2,602,600		2,602,600	2
123,131		1,747,996		1,747,996	3
428,445		21,729,489		21,729,489	4
3			53	53	5
17,618		523,676		523,676	6
295,480	7,295,379	5,207,984		12,503,363	7
275,431		5,717,672		5,717,672	8
2,342			53,973	53,973	9
13,985			327,905	327,905	10
32,332		2,399,681		2,399,681	11
120			6,377	6,377	12
174,382		3,558,253		3,558,253	13
40			990	990	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

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

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	British Columbia Hydro & Power	SF	T-13	NA	NA	NA
2	British Columbia Transmission Corp.	SF	T-13	NA	NA	NA
3	Brookfield Energy Marketing L.P.	SF	T-12	NA	NA	NA
4	California Independent System Operator	AD	T-12	NA	NA	NA
5	California Independent System Operator	SF	T-12	NA	NA	NA
6	Calpine Energy Services, L.P.	SF	T-12	NA	NA	NA
7	Cargill Power Markets, LLC	IF	T-12	NA	NA	NA
8	Cargill Power Markets, LLC	SF	T-11	NA	NA	NA
9	Cargill Power Markets, LLC	SF	T-12	NA	NA	NA
10	Citigroup Energy Inc.	AD	T-12	NA	NA	NA
11	Citigroup Energy Inc.	IF	T-12	NA	NA	NA
12	Citigroup Energy Inc.	SF	T-12	NA	NA	NA
13	City of Anaheim	SF	T-12	NA	NA	NA
14	City of Burbank	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.
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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.
19			251	251	1
54			529	529	2
800		16,000		16,000	3
-3,438			-157,319	-157,319	4
546,589		12,425,345		12,425,345	5
282,299		7,989,434		7,989,434	6
243,196		16,385,278		16,385,278	7
10,648			211,078	211,078	8
354,712		9,385,270		9,385,270	9
			27	27	10
47,550		3,252,420		3,252,420	11
1,504,865		42,388,305		42,388,305	12
16,018		391,617		391,617	13
114,045		3,089,871		3,089,871	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Glendale	SF	T-12	NA	NA	NA
2	City of Hurricane	LF	T-12	NA	NA	NA
3	City of Redding	SF	T-12	NA	NA	NA
4	City of Santa Clara	SF	T-12	NA	NA	NA
5	Clatskanie People's Utility District	SF	T-12	NA	NA	NA
6	Colorado River Commission of Nevada	SF	T-12	NA	NA	NA
7	Constellation Energy Commodities Group	SF	T-11	NA	NA	NA
8	Constellation Energy Commodities Group	SF	T-12	NA	NA	NA
9	Cyrg Energy	LF	T-11	NA	NA	NA
10	DB Energy Trading LLC	SF	T-12	NA	NA	NA
11	EDF Trading North America, LLC	SF	T-11	NA	NA	NA
12	EDF Trading North America, LLC	SF	T-12	NA	NA	NA
13	El Paso Electric Company	SF	T-12	NA	NA	NA
14	Eugene Water & Electric Board	SF	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.
38,258		1,241,084		1,241,084	1
220		15,760		15,760	2
18,790		369,768		369,768	3
57,168		1,580,508		1,580,508	4
238		5,192		5,192	5
173,588		4,561,883		4,561,883	6
4,767			104,703	104,703	7
572,220		15,484,564		15,484,564	8
2,338			53,832	53,832	9
180,688		5,063,347		5,063,347	10
115			1,737	1,737	11
744,551		22,877,088		22,877,088	12
53,556		1,449,308		1,449,308	13
			9	9	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

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	Eugene Water & Electric Board	SF	T-12	NA	NA	NA
2	Exelon Power Team	SF	T-12	NA	NA	NA
3	Gila River Power LLC	SF	T-12	NA	NA	NA
4	Iberdrola Renewables, LLC	LF	T-11	NA	NA	NA
5	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
6	Iberdrola Renewables, LLC	SF	T-11	NA	NA	NA
7	Iberdrola Renewables, LLC	SF	T-12	NA	NA	NA
8	Idaho Power Company	LF	T-11	NA	NA	NA
9	Idaho Power Company	SF	T-11	NA	NA	NA
10	Idaho Power Company	SF	T-12	NA	NA	NA
11	Idaho Power Company	SF	T-13	NA	NA	NA
12	J. Aron & Company	SF	T-12	NA	NA	NA
13	J.P. Morgan Ventures Energy Corporation	SF	T-11	NA	NA	NA
14	J.P. Morgan Ventures Energy 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.
10,268		218,824		218,824	1
800		21,100		21,100	2
71,852		1,829,305		1,829,305	3
3,980			92,228	92,228	4
12,903			299,342	299,342	5
22			661	661	6
558,753		17,214,140		17,214,140	7
1,272			34,381	34,381	8
3,036			70,114	70,114	9
5,300		142,900		142,900	10
363			6,782	6,782	11
69,050		2,178,835		2,178,835	12
4,018			86,162	86,162	13
81,467		1,904,802		1,904,802	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Los Angeles Dept. of Water & Power	AD	T-12	NA	NA	NA
2	Los Angeles Dept. of Water & Power	LU	301	NA	NA	NA
3	Los Angeles Dept. of Water & Power	SF	T-11	NA	NA	NA
4	Los Angeles Dept. of Water & Power	SF	T-12	NA	NA	NA
5	Macquarie Energy LLC	SF	T-12	NA	NA	NA
6	Modesto Irrigation District	SF	T-12	NA	NA	NA
7	Morgan Stanley Capital Group, Inc.	SF	T-11	NA	NA	NA
8	Morgan Stanley Capital Group, Inc.	SF	T-12	NA	NA	NA
9	Municipal Energy Agency of Nebraska	SF	T-12	NA	NA	NA
10	NaturEner Power Watch, LLC	SF	T-13	NA	NA	NA
11	Nevada Power Company	IF	T-12	NA	NA	NA
12	NextEra Energy Power Marketing, LLC	AD	T-11	NA	NA	NA
13	NextEra Energy Power Marketing, LLC	LF	T-11	NA	NA	NA
14	NextEra Energy Power Marketing, LLC	SF	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.
-26			-481	-481	1
469,313		27,777,196		27,777,196	2
270			6,381	6,381	3
31,903		814,725		814,725	4
219,183		6,091,229		6,091,229	5
14,544		386,288		386,288	6
10,163			248,416	248,416	7
2,038,512		63,584,013		63,584,013	8
178,610		4,121,843		4,121,843	9
8			180	180	10
1,092,071		27,203,434		27,203,434	11
224					12
9,829			223,366	223,366	13
15			336	336	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	NextEra Energy Power Marketing, LLC	SF	T-11	NA	NA	NA
2	NextEra Energy Power Marketing, LLC	SF	T-12	NA	NA	NA
3	Noble Americas Gas & Power Corp.	SF	T-12	NA	NA	NA
4	NorthWestern Corporation	SF	T-13	NA	NA	NA
5	Northern California Power Agency	SF	T-12	NA	NA	NA
6	Northpoint Energy Solutions Inc.	SF	T-12	NA	NA	NA
7	PPL EnergyPlus, LLC	SF	T-12	NA	NA	NA
8	PPL Montana, LLC	SF	T-11	NA	NA	NA
9	Pacific Gas & Electric Company	SF	T-11	NA	NA	NA
10	Pacific Gas & Electric Company	SF	T-12	NA	NA	NA
11	Portland General Electric Company	SF	T-11	NA	NA	NA
12	Portland General Electric Company	SF	T-12	NA	NA	NA
13	Portland General Electric Company	SF	T-13	NA	NA	NA
14	Powerex Corporation	LF	T-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24			499	499	1
418		13,032		13,032	2
12,044		367,010		367,010	3
77			1,539	1,539	4
6,982		109,601		109,601	5
5,600		-1,250		-1,250	6
45,067		1,024,865		1,024,865	7
297			7,881	7,881	8
2			25	25	9
657,600		14,335,970		14,335,970	10
12			365	365	11
127,035		2,282,929		2,282,929	12
142			3,687	3,687	13
22,348			502,053	502,053	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Powerex Corporation	SF	T-11	NA	NA	NA
2	Powerex Corporation	SF	T-12	NA	NA	NA
3	Public Service Company of Colorado	AD	320	NA	NA	NA
4	Public Service Company of Colorado	SF	T-12	NA	NA	NA
5	Public Service Company of New Mexico	SF	T-12	NA	NA	NA
6	PUD #1 of Chelan County	SF	T-13	NA	NA	NA
7	PUD #1 of Douglas County	SF	T-12	NA	NA	NA
8	PUD #1 of Snohomish County	SF	T-12	NA	NA	NA
9	PUD #2 of Grant County	SF	T-12	NA	NA	NA
10	PUD #2 of Grant County	SF	T-13	NA	NA	NA
11	Puget Sound Energy, Inc.	SF	T-12	NA	NA	NA
12	Puget Sound Energy, Inc.	SF	T-13	NA	NA	NA
13	Rainbow Energy Marketing Corporation	SF	T-11	NA	NA	NA
14	Rainbow Energy Marketing Corporation	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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
61,961			1,362,160	1,362,160	1
353,378		5,683,666	15,000	5,698,666	2
			353,200	353,200	3
191,207		4,512,251		4,512,251	4
176,961		4,224,013		4,224,013	5
9			391	391	6
175		3,600		3,600	7
3,870		75,050		75,050	8
15,067		245,240		245,240	9
50			1,023	1,023	10
76,488		1,357,600		1,357,600	11
74			1,408	1,408	12
2,292			39,644	39,644	13
39,110		828,072		828,072	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Sacramento Municipal Utility District	AD	250	NA	NA	NA
2	Sacramento Municipal Utility District	LF	250	NA	NA	NA
3	Sacramento Municipal Utility District	SF	T-12	NA	NA	NA
4	Sacramento Municipal Utility District	SF	T-13	NA	NA	NA
5	Salt River Project	SF	T-12	NA	NA	NA
6	San Diego Gas & Electric Company	SF	T-12	NA	NA	NA
7	Seattle City Light	SF	T-12	NA	NA	NA
8	Seattle City Light	SF	T-13	NA	NA	NA
9	Sempra Generation	SF	T-12	NA	NA	NA
10	Shell Energy North America (US), L.P.	IF	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**

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.
			1,246,947	1,246,947	1
529,268		13,612,773		13,612,773	2
56,249		1,053,108		1,053,108	3
7			86	86	4
102,393		2,550,811		2,550,811	5
800		19,200		19,200	6
23,695		191,890		191,890	7
58			925	925	8
34,211		955,834		955,834	9
60,783		2,175,737		2,175,737	10
308			8,371	8,371	11
492,878		11,699,910		11,699,910	12
459			9,379	9,379	13
973			23,102	23,102	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	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	Southern California Public Power Author	SF	T-11	NA	NA	NA
7	Southwestern Public Service Company	SF	T-12	NA	NA	NA
8	Tacoma Power	SF	T-12	NA	NA	NA
9	Tenaska Power Services Co.	SF	T-11	NA	NA	NA
10	Tenaska Power Services Co.	SF	T-12	NA	NA	NA
11	The Energy Authority, Inc.	SF	T-11	NA	NA	NA
12	The Energy Authority, Inc.	SF	T-12	NA	NA	NA
13	TransAlta Energy Marketing (U.S.) Inc.	SF	T-11	NA	NA	NA
14	TransAlta Energy Marketing (U.S.) Inc.	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.
596			13,231	13,231	1
327,783		8,058,380		8,058,380	2
16,135			368,406	368,406	3
50			1,261	1,261	4
155,342		4,000,732		4,000,732	5
21			415	415	6
76,515		1,839,944		1,839,944	7
7,287		129,918		129,918	8
1,387			35,801	35,801	9
45,204		1,016,581		1,016,581	10
82			1,192	1,192	11
16,154		393,992		393,992	12
1,347			24,892	24,892	13
297,782		6,396,748		6,396,748	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

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

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	TransCanada Energy Sales Ltd.	SF	T-12	NA	NA	NA
2	Tri-State Gen. & Trans.	SF	T-11	NA	NA	NA
3	Tri-State Gen. & Trans.	SF	T-12	NA	NA	NA
4	Tucson Electric Power Company	SF	T-12	NA	NA	NA
5	Turlock Irrigation District	SF	T-12	NA	NA	NA
6	Twin Eagle Resource Management, LLC	SF	T-12	NA	NA	NA
7	UNS Electric, Inc.	SF	T-12	NA	NA	NA
8	Utah Associated Municipal Power Systems	SF	T-11	NA	NA	NA
9	Utah Associated Municipal Power Systems	SF	T-12	NA	NA	NA
10	Utah Municipal Power Agency	LF	433	34	34	34
11	Utah Municipal Power Agency	SF	T-3	NA	NA	NA
12	Western Area Power Administration	SF	T-11	NA	NA	NA
13	Western Area Power Administration	SF	T-12	NA	NA	NA
14	Western Area Power Administration	SF	T-13	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,989		42,488		42,488	1
2,292			58,159	58,159	2
322,926		7,578,373		7,578,373	3
230,961		5,611,895		5,611,895	4
6,960		159,520		159,520	5
8,538		260,886		260,886	6
315,864		8,458,036		8,458,036	7
436			11,637	11,637	8
5,448		143,206		143,206	9
200,921	4,396,200	4,654,444		9,050,644	10
18,676		411,289		411,289	11
2,019			40,999	40,999	12
690,070		19,722,589		19,722,589	13
2			37	37	14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Netting - Bookouts		NA	NA	NA	NA
2	Reserve for potential refunds		NA	NA	NA	NA
3	Netting - Trading		NA	NA	NA	NA
4	Accrual		NA	NA	NA	NA
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-5,563,059			-177,742,246	-177,742,246	1
			-634,716	-634,716	2
			-2,036,446	-2,036,446	3
-7,326			-115,760	-115,760	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
223,987	4,441,941	6,481,541	-158,949	10,764,533	
11,645,802	11,691,579	482,835,347	-174,721,835	319,805,091	
11,869,789	**16,133,520**	**489,316,888**	**-174,880,784**	**330,569,624**	

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.: 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, Sales for resale, during the period.

Schedule Page: 310.1 Line No.: 1 Column: j

Reserve share.

Schedule Page: 310.1 Line No.: 5 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 7 Column: b

Black Hills Power, Inc. - FERC 441 - contract termination date: December 31, 2023.

Schedule Page: 310.1 Line No.: 9 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 Bonneville Power Administration] - contract termination date: Upon mutual agreement.

Schedule Page: 310.1 Line No.: 9 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 10 Column: b

Bonneville Power Administration - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (2nd revised S.A. 179)] - Contract termination date: September 30, 2025 and (1st revised S.A. 656) - contract termination date: August 31, 2030.

Schedule Page: 310.1 Line No.: 10 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 12 Column: j

Transmission losses.

Schedule Page: 310.1 Line No.: 14 Column: j

Reserve share.

Schedule Page: 310.2 Line No.: 1 Column: a

This footnote applies to all occurrences of “British Columbia Hydro & Power” on pages 310–311. Complete name is British Columbia Hydro and Power Authority.

Schedule Page: 310.2 Line No.: 1 Column: j

Reserve share.

Schedule Page: 310.2 Line No.: 2 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.: 2 Column: j

Reserve share.

Schedule Page: 310.2 Line No.: 4 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.: 4 Column: b

Settlement adjustment.

Schedule Page: 310.2 Line No.: 4 Column: j

Settlement adjustment.

Schedule Page: 310.2 Line No.: 8 Column: j

Transmission losses.

Schedule Page: 310.2 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 310.2 Line No.: 10 Column: j
Settlement adjustment.

Schedule Page: 310.3 Line No.: 2 Column: b
City of Hurricane - FERC T-12 - contract termination date: August 31, 2007.

Schedule Page: 310.3 Line No.: 7 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.: 7 Column: j
Transmission losses.

Schedule Page: 310.3 Line No.: 9 Column: b
Cyrg Energy - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (2nd revised S.A. 568)] - contract termination date: August 30, 2029.

Schedule Page: 310.3 Line No.: 9 Column: j
Transmission losses.

Schedule Page: 310.3 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.3 Line No.: 14 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 4 Column: b
Iberdrola Renewables, LLC - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (6th revised S.A. 279)] - contract termination date: April 30, 2014.

Schedule Page: 310.4 Line No.: 4 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 5 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 6 Column: j
Unauthorized use charges.

Schedule Page: 310.4 Line No.: 8 Column: b
Idaho Power Company - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (6th revised S.A. 212)] - contract termination date: May 31, 2014.

Schedule Page: 310.4 Line No.: 8 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 9 Column: j
Transmission losses.

Schedule Page: 310.4 Line No.: 11 Column: j
Reserve share.

Schedule Page: 310.4 Line No.: 13 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 1 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.: 1 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 1 Column: j
Settlement adjustment.

Schedule Page: 310.5 Line No.: 3 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 7 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 10 Column: j
Reserve share.

Schedule Page: 310.5 Line No.: 12 Column: b
Settlement adjustment.

Schedule Page: 310.5 Line No.: 13 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: October 31, 2014.

Schedule Page: 310.5 Line No.: 13 Column: j
Transmission losses.

Schedule Page: 310.5 Line No.: 14 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 1 Column: j
Unauthorized use charges.

Schedule Page: 310.6 Line No.: 4 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 8 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 9 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 11 Column: j
Transmission losses.

Schedule Page: 310.6 Line No.: 13 Column: j
Reserve share.

Schedule Page: 310.6 Line No.: 14 Column: b
Powerex Corporation - FERC T-11 [Point-to-Point Transmission Service under the Open Access Transmission Tariff (7th revised S.A. 169)] - contract termination date: October 31, 2020.

Schedule Page: 310.6 Line No.: 14 Column: j
Transmission losses.

Schedule Page: 310.7 Line No.: 1 Column: j
Transmission losses.

Schedule Page: 310.7 Line No.: 2 Column: j
Pond sales.

Schedule Page: 310.7 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 310.7 Line No.: 3 Column: j
Settlement adjustment.

Schedule Page: 310.7 Line No.: 6 Column: a
This footnote applies to all occurrences of “PUD #1 of Chelan County” on pages 310–311. Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 310.7 Line No.: 6 Column: j
Reserve share.

Schedule Page: 310.7 Line No.: 7 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: 310.7 Line No.: 8 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: 310.7 Line No.: 9 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: 310.7 Line No.: 10 Column: j
Reserve share.

Schedule Page: 310.7 Line No.: 12 Column: j
Reserve share.

Schedule Page: 310.7 Line No.: 13 Column: j
Transmission losses.

Schedule Page: 310.8 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 310.8 Line No.: 1 Column: j

Settlement adjustment.

Schedule Page: 310.8 Line No.: 2 Column: b

Sacramento Municipal Utility District - FERC 250 - contract termination date: December 31, 2014.

Schedule Page: 310.8 Line No.: 4 Column: j

Reserve share.

Schedule Page: 310.8 Line No.: 8 Column: j

Reserve share.

Schedule Page: 310.8 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.8 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 terminated September 2012.

Schedule Page: 310.8 Line No.: 13 Column: j

Transmission losses.

Schedule Page: 310.8 Line No.: 14 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 1 Column: j

Reserve share.

Schedule Page: 310.9 Line No.: 3 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 4 Column: j

Unauthorized use charges.

Schedule Page: 310.9 Line No.: 6 Column: j

Unauthorized use charges.

Schedule Page: 310.9 Line No.: 9 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 11 Column: j

Transmission losses.

Schedule Page: 310.9 Line No.: 13 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 2 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.: 2 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 8 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 10 Column: b

Utah Municipal Power Agency - FERC 433 - contract termination date: June 30, 2017.

Schedule Page: 310.10 Line No.: 12 Column: j

Transmission losses.

Schedule Page: 310.10 Line No.: 14 Column: j

Reserve share.

Schedule Page: 310.11 Line No.: 1 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.11 Line No.: 2 Column: j

Transmission losses.

Schedule Page: 310.11 Line No.: 3 Column: j

Reflects transactions that did not physically settle.

Schedule Page: 310.11 Line No.: 4 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, Sales for resale, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	19,142,283	19,391,612
5	(501) Fuel	768,997,788	722,758,588
6	(502) Steam Expenses	41,809,206	38,138,103
7	(503) Steam from Other Sources	3,937,027	3,583,830
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,896,688	4,190,528
10	(506) Miscellaneous Steam Power Expenses	56,759,531	52,707,159
11	(507) Rents	396,587	277,654
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	894,939,110	841,047,474
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,378,884	6,365,300
16	(511) Maintenance of Structures	25,384,395	23,596,390
17	(512) Maintenance of Boiler Plant	107,992,173	109,128,194
18	(513) Maintenance of Electric Plant	35,012,328	39,898,808
19	(514) Maintenance of Miscellaneous Steam Plant	12,158,343	13,319,308
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	186,926,123	192,308,000
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,081,865,233	1,033,355,474
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	4,711,673	3,787,003
45	(536) Water for Power	134,519	257,504
46	(537) Hydraulic Expenses	4,265,329	3,696,681
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	18,412,058	21,669,423
49	(540) Rents	661,711	-404,504
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	28,185,290	29,006,107
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	388	1,891
54	(542) Maintenance of Structures	825,279	1,030,119
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,088,303	2,430,112
56	(544) Maintenance of Electric Plant	1,974,573	2,553,749
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,936,126	2,961,681
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,824,669	8,977,552
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	36,009,959	37,983,659

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	369,904	429,811
63	(547) Fuel	364,507,540	367,320,902
64	(548) Generation Expenses	17,430,953	15,368,434
65	(549) Miscellaneous Other Power Generation Expenses	9,147,157	21,289,631
66	(550) Rents	3,662,580	4,253,868
67	TOTAL Operation (Enter Total of lines 62 thru 66)	395,118,134	408,662,646
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	2,291,254	2,938,948
71	(553) Maintenance of Generating and Electric Plant	25,781,191	10,918,597
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,966,376	4,783,736
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	30,038,821	18,641,281
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	425,156,955	427,303,927
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	535,586,277	398,261,268
77	(556) System Control and Load Dispatching	1,546,050	1,744,114
78	(557) Other Expenses	62,779,248	60,776,842
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	599,911,575	460,782,224
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,142,943,722	1,959,425,284
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,532,584	5,689,657
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	6,733,470	7,794,035
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	239,500	
89	(561.5) Reliability, Planning and Standards Development	850,396	984,307
90	(561.6) Transmission Service Studies	127,861	206,982
91	(561.7) Generation Interconnection Studies	617,977	763,228
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,984,932	2,647,395
94	(563) Overhead Lines Expenses	285,237	259,051
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	142,125,115	138,234,854
97	(566) Miscellaneous Transmission Expenses	3,696,068	3,568,851
98	(567) Rents	1,497,301	2,549,553
99	TOTAL Operation (Enter Total of lines 83 thru 98)	164,690,441	162,697,913
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,486,358	2,060,726
102	(569) Maintenance of Structures	1,145	300
103	(569.1) Maintenance of Computer Hardware	203,102	103,365
104	(569.2) Maintenance of Computer Software	1,001,012	1,119,442
105	(569.3) Maintenance of Communication Equipment	3,270,838	3,356,135
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	11,423,719	11,231,343
108	(571) Maintenance of Overhead Lines	20,575,947	22,369,881
109	(572) Maintenance of Underground Lines	82,622	169,531
110	(573) Maintenance of Miscellaneous Transmission Plant	2,748,898	1,607,372
111	TOTAL Maintenance (Total of lines 101 thru 110)	41,793,641	42,018,095
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	206,484,082	204,716,008

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	14,093,118	14,865,204
135	(581) Load Dispatching	13,036,839	13,254,105
136	(582) Station Expenses	4,078,201	4,206,539
137	(583) Overhead Line Expenses	5,526,165	6,624,463
138	(584) Underground Line Expenses	249	1,186
139	(585) Street Lighting and Signal System Expenses	222,740	231,056
140	(586) Meter Expenses	7,071,031	7,978,791
141	(587) Customer Installations Expenses	12,473,499	13,297,857
142	(588) Miscellaneous Expenses	4,562,147	5,452,451
143	(589) Rents	3,366,940	3,011,807
144	TOTAL Operation (Enter Total of lines 134 thru 143)	64,430,929	68,923,459
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	4,472,548	4,424,569
147	(591) Maintenance of Structures	1,310,306	2,476,425
148	(592) Maintenance of Station Equipment	10,993,806	14,330,166
149	(593) Maintenance of Overhead Lines	88,718,266	89,892,555
150	(594) Maintenance of Underground Lines	20,313,015	22,649,570
151	(595) Maintenance of Line Transformers	957,612	893,541
152	(596) Maintenance of Street Lighting and Signal Systems	3,704,762	4,076,102
153	(597) Maintenance of Meters	6,749,398	5,647,204
154	(598) Maintenance of Miscellaneous Distribution Plant	2,027,649	1,787,180
155	TOTAL Maintenance (Total of lines 146 thru 154)	139,247,362	146,177,312
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	203,678,291	215,100,771
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,603,420	2,930,313
160	(902) Meter Reading Expenses	20,679,578	21,907,551
161	(903) Customer Records and Collection Expenses	53,770,351	56,314,393
162	(904) Uncollectible Accounts	14,337,468	14,586,410
163	(905) Miscellaneous Customer Accounts Expenses	142,188	205,123
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	91,533,005	95,943,790

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

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	301,706	302,255
168	(908) Customer Assistance Expenses	103,156,102	103,945,691
169	(909) Informational and Instructional Expenses	3,294,390	5,081,263
170	(910) Miscellaneous Customer Service and Informational Expenses	204,557	183,174
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	106,956,755	109,512,383
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	74,368,102	68,148,776
182	(921) Office Supplies and Expenses	8,706,781	9,330,613
183	(Less) (922) Administrative Expenses Transferred-Credit	27,128,855	29,007,646
184	(923) Outside Services Employed	13,277,918	10,190,059
185	(924) Property Insurance	16,404,849	24,984,814
186	(925) Injuries and Damages	48,931,701	7,284,849
187	(926) Employee Pensions and Benefits		
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	22,965,972	21,857,100
190	(929) (Less) Duplicate Charges-Cr.	4,869,262	6,822,162
191	(930.1) General Advertising Expenses	4,948	5,360
192	(930.2) Miscellaneous General Expenses	7,338,998	15,710,771
193	(931) Rents	6,720,354	6,614,680
194	TOTAL Operation (Enter Total of lines 181 thru 193)	166,721,506	128,297,214
195	Maintenance		
196	(935) Maintenance of General Plant	21,518,172	24,360,143
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	188,239,678	152,657,357
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	2,939,835,533	2,737,355,593

Schedule Page: 320 Line No.: 49 Column: c

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, 2012 and 2011, pensions and benefits expense was $144,687,083 and $156,716,703, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 Electric Power Cooperative	SF		NA	NA	NA
3	Arizona Public Service Company	AD		NA	NA	NA
4	Arizona Public Service Company	LF		NA	NA	NA
5	Arizona Public Service Company	SF		NA	NA	NA
6	Avista Corporation	SF		NA	NA	NA
7	BNP Paribas Energy Trading GP	SF		NA	NA	NA
8	BP Corporation North America, Inc.	SF		NA	NA	NA
9	BP Energy Company	SF		NA	NA	NA
10	Ballard Hog Farms Inc.	LU		0.01	0.01	0.01
11	Barclays Bank PLC	SF		NA	NA	NA
12	Basin Electric Power Cooperative	SF		NA	NA	NA
13	Beaver City Corporation	LF		NA	NA	NA
14	Bell Mountain Hydro, 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)	
							1
70				1,355		1,355	2
					94,281	94,281	3
60,856				1,657,766		1,657,766	4
150,602				4,515,580	75,593	4,591,173	5
71,221				1,858,822	4,303	1,863,125	6
6				242		242	7
					-9,393,174	-9,393,174	8
528,965				9,468,834	-1,093,562	8,375,272	9
60			302	2,431		2,733	10
283,278				12,466,592	-356,180	12,110,412	11
1,011				18,415		18,415	12
75				6,250		6,250	13
1,027				76,989		76,989	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Big Top, LLC	LU		NA	NA	NA
2	Biomass One, L.P.	LU		NA	NA	NA
3	Birch Power Company, Inc.	LU		NA	NA	NA
4	Black Cap Solar, LLC	OS		NA	NA	NA
5	Black Hills Power, Inc.	AD		NA	NA	NA
6	Black Hills Power, Inc.	LU		NA	NA	NA
7	Black Hills Power, Inc.	SF		NA	NA	NA
8	Blanding City Corporation	LF		NA	NA	NA
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	LU		2.9	3.8	1.6
13	Butter Creek Power, LLC	LU		NA	NA	NA
14	C Drop Hydro, 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.
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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)	
3,844				260,709		260,709	1
127,571				8,725,321	3,047,953	11,773,274	2
15,362				888,603		888,603	3
377				10,026		10,026	4
-103					199,875	199,875	5
10					504,302	504,302	6
12,751				402,055		402,055	7
393				29,453		29,453	8
					875,251	875,251	9
1,786					69,557	69,557	10
541,849				9,914,969	42,511	9,957,480	11
15,586			271,905	1,843,813		2,115,718	12
13,093				888,593		888,593	13
2,619				135,034		135,034	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	CDM Hydroelectric Company	LU		NA	NA	NA
2	CER Generation II, LLC	IU		200	166	36
3	California Independent System Operator	AD		NA	NA	NA
4	California Independent System Operator	SF		NA	NA	NA
5	Calpine Energy Services, L.P.	SF		NA	NA	NA
6	Cameron A. Curtiss	LU		NA	NA	NA
7	Cargill Power Markets, LLC	IF		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		5.9	5.1	4.2
12	Chevron U.S.A. Inc.	LU		NA	NA	NA
13	Citigroup Energy Inc.	SF		NA	NA	NA
14	City of Albany	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.
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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)	
28,427				1,634,850		1,634,850	1
272,791			5,208,000		12,478,140	17,686,140	2
-2,059					-64,752	-64,752	3
275,609				6,600,374		6,600,374	4
667,881				17,866,171		17,866,171	5
101				5,284		5,284	6
240,949				17,621,558		17,621,558	7
138,468				2,799,857	869,476	3,669,333	8
4,946				292,708		292,708	9
					-11,677	-11,677	10
52,300			608,150	4,846,859		5,455,009	11
45,768				2,894,381		2,894,381	12
1,044,875				31,348,541	-9,175,508	22,173,033	13
829				57,170		57,170	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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 Anaheim	SF		NA	NA	NA
2	City of Burbank	SF		NA	NA	NA
3	City of Glendale	SF		NA	NA	NA
4	City of Hurricane	LF		NA	NA	NA
5	City of Portland, Water Bureau	LU		NA	NA	NA
6	City of Preston Idaho	LU		NA	NA	NA
7	City of Redding	SF		NA	NA	NA
8	City of Walla Walla	LU		2.0	1.9	1.5
9	Clatskanie People's Utility District	SF		NA	NA	NA
10	Colorado River Commission of Nevada	SF		NA	NA	NA
11	Commercial Energy Management Inc.	LU		NA	NA	NA
12	Constellation Energy Commodities Group	SF		NA	NA	NA
13	Cottonwood Hydro, LLC	AD		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)	
2				38		38	1
14,323				568,963		568,963	2
1,570				67,520		67,520	3
1,928				138,717		138,717	4
49				2,015		2,015	5
2,557				135,558		135,558	6
20				-800		-800	7
13,637			138,980	1,986,857		2,125,837	8
1,840				13,240		13,240	9
128				4,021		4,021	10
1,877				100,966		100,966	11
143,664				3,718,576	-65,547	3,653,029	12
-60					-3,275	-3,275	13
2,994				141,210		141,210	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	DB Energy Trading LLC	SF		NA	NA	NA
2	Deschutes Valley Water District	LU		5.8	4.1	3.3
3	Deseret Generation & Transmission Coop	LF		100	100	91
4	Deutsche Bank AG	SF		NA	NA	NA
5	Douglas County	LU		0.8	1.2	0.7
6	Douglas County, Inc.	LU		NA	NA	NA
7	Draper Irrigation Company	AD		NA	NA	NA
8	Draper Irrigation Company	IU		NA	NA	NA
9	Dry Creek LLC	LU		NA	NA	NA
10	Duane Wiggins Hydro, Inc.	IU		NA	NA	NA
11	EDF Trading North America, LLC	SF		NA	NA	NA
12	Eagle Point Irrigation District	LU		0.8	0.5	0.4
13	El Paso Electric Company	SF		NA	NA	NA
14	Eugene Water & Electric Board	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)	
467,915				9,614,090		9,614,090	1
28,734			567,894	3,232,576		3,800,470	2
679,693			15,031,898	13,026,114	3,936,927	31,994,939	3
					-4,248,587	-4,248,587	4
7,179			83,226	905,218		988,444	5
10,143				177,038		177,038	6
485					14,283	14,283	7
63				2,698		2,698	8
10,268				552,993		552,993	9
15				787		787	10
735,474				21,971,661	1,138,781	23,110,442	11
3,574			45,865	423,858		469,723	12
10,200				290,598	28	290,626	13
51,931				914,420		914,420	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Eurus Combine Hills I, LLC	LU		NA	NA	NA
2	Evergreen BioPower, LLC	LU		NA	NA	NA
3	Falls Creek H.P. Limited Partnership	LU		3.6	3.8	2.0
4	Farmers Irrigation District	LU		NA	NA	NA
5	Fillmore City Corporation	LF		NA	NA	NA
6	Finley BioEnergy, LLC	LU		NA	NA	NA
7	Flathead Electric Cooperative, Inc.	LF		NA	NA	NA
8	Four Corners Windfarm, LLC	LU		NA	NA	NA
9	Four Mile Canyon Windfarm, LLC	LU		NA	NA	NA
10	George DeRuyter & Sons Dairy	LU		0.8	1.0	0.8
11	Georgetown Irrigation Company	LU		NA	NA	NA
12	Gila River Power LLC	SF		NA	NA	NA
13	Grand Valley Power	LF		NA	NA	NA
14	GrowPro, Inc.	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: 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.
108,721				4,922,879		4,922,879	1
34,659				2,158,175		2,158,175	2
19,554			255,074	2,197,882		2,452,956	3
24,377				1,578,289		1,578,289	4
182				19,680		19,680	5
34,089				2,342,922		2,342,922	6
478					8,974	8,974	7
28,521				1,926,532		1,926,532	8
25,965				1,758,543		1,758,543	9
6,710			14,014	416,932		430,946	10
2,023				114,462		114,462	11
127,206				4,011,092		4,011,092	12
74				14,415		14,415	13
				12		12	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Harold Foster & Robert Walker	LU		NA	NA	NA
2	Hermiston Generating Company, L.P.	AD		NA	NA	NA
3	Hermiston Generating Company, L.P.	LU		223	223	172
4	Iberdrola Renewables, LLC	OS		NA	NA	NA
5	Iberdrola Renewables, LLC	SF		NA	NA	NA
6	Idaho Falls, City of	AD		NA	NA	NA
7	Idaho Falls, City of	LU		NA	NA	NA
8	Idaho Power Company	OS		NA	NA	NA
9	Idaho Power Company	SF		NA	NA	NA
10	Ingram Warm Springs Ranch Partnership	LU		NA	NA	NA
11	Intermountain Power Agency	LU		NA	NA	NA
12	J Bar 9 Ranch, Inc.	AD		NA	NA	NA
13	J Bar 9 Ranch, Inc.	LU		NA	NA	NA
14	J. Aron & 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: 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.
857				31,620		31,620	1
1					61,431	61,431	2
1,146,891			36,089,626	48,441,607	455,927	84,987,160	3
					96,055	96,055	4
1,207,842				29,103,013	686,013	29,789,026	5
					-10,524	-10,524	6
68,969					2,900,829	2,900,829	7
100				1,500		1,500	8
54,027				1,201,467	3,017	1,204,484	9
1,224				70,730		70,730	10
469,313				27,777,196		27,777,196	11
4					63	63	12
67				1,607		1,607	13
15,613				648,830	-5,544,603	-4,895,773	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	JP Morgan Ventures Energy Corporation	SF		NA	NA	NA
2	Jake Amy	LU		NA	NA	NA
3	Joseph Community Solar LLC	AD		NA	NA	NA
4	Joseph Community Solar LLC	LU		NA	NA	NA
5	Kennecott Utah Copper LLC	LU		NA	NA	NA
6	Lacomb Irrigation District	LU		NA	NA	NA
7	Los Angeles Dept. of Water & Power	AD		NA	NA	NA
8	Los Angeles Dept. of Water & Power	SF		NA	NA	NA
9	Lower Valley Energy, Inc.	AD		NA	NA	NA
10	Lower Valley Energy, Inc.	IU		NA	NA	NA
11	Lower Valley Energy, Inc.	LU		NA	NA	NA
12	Loyd Fery	LU		NA	NA	NA
13	Macquarie Energy LLC	SF		NA	NA	NA
14	Marsh Valley Hydro Electric Company	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
386,822				7,790,916	-4,772,593	3,018,323	1
1,724				94,429		94,429	2
44					1,916	1,916	3
667				20,484		20,484	4
56,610				1,921,698	1,824,932	3,746,630	5
3,642				75,330	35,812	111,142	6
61					2,300	2,300	7
86,912				3,810,498	13	3,810,511	8
					3,244	3,244	9
5,822				396,577		396,577	10
1,107				58,928		58,928	11
348				22,539		22,539	12
295,486				7,984,850	-42,022	7,942,828	13
5,083				292,280		292,280	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Meadow Creek Project Company LLC	LU		NA	NA	NA
2	Middle Fork Irrigation District	LU		NA	NA	NA
3	Mink Creek Hydro LLC	LU		NA	NA	NA
4	Monsanto Company	IU		NA	NA	NA
5	Morgan City Corporation	LF		NA	NA	NA
6	Morgan Stanley Capital Group, Inc.	AD		NA	NA	NA
7	Morgan Stanley Capital Group, Inc.	SF		NA	NA	NA
8	Mountain Energy, Inc.	LU		NA	NA	NA
9	Mountain Wind Power II, LLC	LU		NA	NA	NA
10	Mountain Wind Power, LLC	LU		NA	NA	NA
11	Municipal Energy Agency of Nebraska	SF		NA	NA	NA
12	NaturEner Power Watch, LLC	SF		NA	NA	NA
13	Nephi City Corporation	LF		NA	NA	NA
14	Nevada Power 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 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.
29,683				1,509,603		1,509,603	1
25,232				1,572,734		1,572,734	2
8,861				493,901		493,901	3
					18,255,735	18,255,735	4
25				2,551		2,551	5
							6
1,871,743				58,506,762	-1,437,314	57,069,448	7
96				6,574		6,574	8
227,793				14,574,484		14,574,484	9
171,518				9,522,713		9,522,713	10
100				2,200		2,200	11
1					23	23	12
16				1,865		1,865	13
170,658				5,538,726	304,867	5,843,593	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	NextEra Energy Power Marketing, LLC	SF		NA	NA	NA
2	Nicholson's Sunny Bar Ranch	LU		NA	NA	NA
3	Noble Americas Gas & Power Corp.	SF		NA	NA	NA
4	NorthWestern Corporation	SF		NA	NA	NA
5	Nucor Corporation	IF		NA	NA	NA
6	O.J. Power Company	LU		NA	NA	NA
7	Oregon Environmental Industries, LLC	LU		NA	NA	NA
8	Oregon Institute of Technology	LU		NA	NA	NA
9	Oregon State University	LU		NA	NA	NA
10	Oregon Trail Windfarm, LLC	LU		NA	NA	NA
11	PPL EnergyPlus, LLC	SF		NA	NA	NA
12	Pacific Canyon Windfarm, LLC	LU		NA	NA	NA
13	Pacific Gas & Electric Company	SF		NA	NA	NA
14	Paul Luckey	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
10,070				170,675		170,675	1
1,870				107,012		107,012	2
14,000				240,680		240,680	3
190					4,336	4,336	4
					5,446,800	5,446,800	5
684				36,019		36,019	6
22,079				1,376,978		1,376,978	7
							8
386				9,984		9,984	9
26,111				1,763,384		1,763,384	10
131,134				2,650,126		2,650,126	11
19,839				1,344,769		1,344,769	12
20,000				520,976		520,976	13
282				38,030		38,030	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Payson City Corporation	LF		NA	NA	NA
2	Platte River Power Authority	SF		NA	NA	NA
3	Portland General Electric Company	AD		NA	NA	NA
4	Portland General Electric Company	LF		NA	NA	NA
5	Portland General Electric Company	SF		NA	NA	NA
6	Power County Wind Park North, LLC	AD		NA	NA	NA
7	Power County Wind Park North, LLC	LU		NA	NA	NA
8	Power County Wind Park South, LLC	AD		NA	NA	NA
9	Power County Wind Park South, LLC	LU		NA	NA	NA
10	Powerex Corporation	SF		NA	NA	NA
11	Provo City Corporation	LF		NA	NA	NA
12	Public Service Company of Colorado	SF		NA	NA	NA
13	Public Service Company of New Mexico	SF		NA	NA	NA
14	PUD No. 1 of Chelan County	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)	
17				1,988		1,988	1
3,693					88,370	88,370	2
					-230,124	-230,124	3
12,024					270,000	270,000	4
58,728				967,018	5,439	972,457	5
197					5,685	5,685	6
70,382				3,979,854		3,979,854	7
16					461	461	8
64,743				3,664,717		3,664,717	9
171,142				5,132,828	-29,792	5,103,036	10
51				4,397		4,397	11
5,446				225,180		225,180	12
168,082				4,717,802	114,789	4,832,591	13
					9,540	9,540	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	PUD No. 1 of Chelan County	SF		NA	NA	NA
2	PUD No. 1 of Cowlitz County	OS		NA	NA	NA
3	PUD No. 1 of Douglas County	AD		NA	NA	NA
4	PUD No. 1 of Douglas County	AD		NA	NA	NA
5	PUD No. 1 of Douglas County	LF		NA	NA	NA
6	PUD No. 1 of Douglas County	LU		NA	NA	NA
7	PUD No. 1 of Douglas County	SF		NA	NA	NA
8	PUD No. 1 of Snohomish County	SF		NA	NA	NA
9	PUD No. 2 of Grant County	AD		NA	NA	NA
10	PUD No. 2 of Grant County	LF		14	NA	NA
11	PUD No. 2 of Grant County	LU		NA	NA	NA
12	PUD No. 2 of Grant County	SF		NA	NA	NA
13	Puget Sound Energy, Inc.	SF		NA	NA	NA
14	RES Ag - Oak Lea 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)	
23,323				403,690	2,434	406,124	1
					-93,738	-93,738	2
					-110,579	-110,579	3
					-150,834	-150,834	4
88,266				2,367,669		2,367,669	5
245,509					3,263,025	3,263,025	6
34,255				645,995	460	646,455	7
45,205				707,610		707,610	8
					-817,762	-817,762	9
58,852			104,746	4,028,260	206,201	4,339,207	10
135,994					-4,695,046	-4,695,046	11
43,157				946,381	1,894	948,275	12
116,892				2,524,103	6,220	2,530,323	13
1,015				41,694		41,694	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Rainbow Energy Marketing Corporation	SF		NA	NA	NA
2	Ralphs Ranch, Inc.	LU		NA	NA	NA
3	Riverside, City of	SF		NA	NA	NA
4	Rock River 1, LLC	LU		NA	NA	NA
5	Rocky Mountain Generation Coop	SF		NA	NA	NA
6	Roseburg Forest Products Company	AD		NA	NA	NA
7	Roseburg Forest Products Company	LU		NA	NA	NA
8	Roseburg Forest Products Company	OS		NA	NA	NA
9	Roseburg LFG Energy, LLC	AD		NA	NA	NA
10	Roseburg LFG Energy, LLC	LU		NA	NA	NA
11	Rough & Ready Lumber Company	LU		NA	NA	NA
12	Roush Hydro Inc.	AD		NA	NA	NA
13	Roush Hydro Inc.	LU		NA	NA	NA
14	Sacramento Municipal Utility District	AD		NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	
130,326				3,627,229		3,627,229	1
215				28,892		28,892	2
100				900		900	3
135,098				4,793,270		4,793,270	4
11,925				183,357		183,357	5
292							6
36,743				1,559,074		1,559,074	7
16,274				905,655		905,655	8
170					8,370	8,370	9
11,411				592,655		592,655	10
8,196				559,319		559,319	11
-8					-512	-512	12
297				20,510		20,510	13
					148,541	148,541	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Sacramento Municipal Utility District	LF		NA	NA	NA
2	Sacramento Municipal Utility District	SF		NA	NA	NA
3	Salt River Project	SF		NA	NA	NA
4	San Diego Gas & Electric Company	SF		NA	NA	NA
5	Sand Ranch Windfarm, LLC	LU		NA	NA	NA
6	Santiam Water Control District	LU		0.2	0.2	0.2
7	Seattle City Light	AD		NA	NA	NA
8	Seattle City Light	SF		NA	NA	NA
9	Sempra Generation	SF		NA	NA	NA
10	Shell Energy North America (US), L.P.	AD		NA	NA	NA
11	Shell Energy North America (US), L.P.	IF		NA	NA	NA
12	Shell Energy North America (US), L.P.	SF		NA	NA	NA
13	Shoshone Irrigation District	LU		2.6	1.4	1.4
14	Sierra Pacific Power 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 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.
218,983				4,132,209		4,132,209	1
1,234				25,029		25,029	2
98,339				3,375,854	6,322	3,382,176	3
1,047				46,951		46,951	4
24,317				1,646,437		1,646,437	5
1,609			13,632	152,919		166,551	6
					300,000	300,000	7
196,711				3,476,780	2,906	3,479,686	8
172,625				4,962,788		4,962,788	9
					19	19	10
60,720				2,538,336		2,538,336	11
368,953				6,900,844	-1,382,028	5,518,816	12
10,185			188,293	434,781		623,074	13
17,200				535,735	2,013	537,748	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	SF		NA	NA	NA
2	Simplot Phosphates LLC	LU		10	13	7
3	Slate Creek Hydro Company, Inc.	AD		NA	NA	NA
4	Slate Creek Hydro Company, Inc.	LU		2.4	1.8	0.8
5	Solwatt LLC	LU		NA	NA	NA
6	Southern California Edison Company	SF		NA	NA	NA
7	Southwestern Public Service Company	SF		NA	NA	NA
8	Spanish Fork Wind Park 2, LLC	LU		NA	NA	NA
9	Sprague Hydro, LLC	LU		0.5	0.5	0.2
10	Springville City Corporation	LF		NA	NA	NA
11	Stahlbush Island Farms, Inc.	IU		NA	NA	NA
12	Strawberry Electric Service District	LF		NA	NA	NA
13	Sunnyside Cogeneration Associates	LU		52	53	43
14	Swalley Irrigation District	LU		NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,915					381,704	381,704	1
79,938			494,000	3,991,543		4,485,543	2
					76,747	76,747	3
7,970			120,921	844,985		965,906	4
443				15,862		15,862	5
7,949				94,188		94,188	6
5,013				133,964		133,964	7
48,703				2,555,950		2,555,950	8
2,577			55,233	304,346		359,579	9
56				6,891		6,891	10
8,213				428,422		428,422	11
61				5,217		5,217	12
418,433			10,621,050	15,945,696		26,566,746	13
2,115				145,570		145,570	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Tacoma Power	SF		NA	NA	NA
2	Tata Chemicals (Soda Ash) Partners	OS		NA	NA	NA
3	Tenaska Power Services Co.	SF		NA	NA	NA
4	Tesoro Refining and Marketing Company	LU		NA	NA	NA
5	Thayn Hydro LLC	LU		0.3	0.4	0.3
6	The Energy Authority, Inc.	SF		NA	NA	NA
7	The Town of the City of Buffalo	LU		0.2	0.2	0.2
8	Three Buttes Windpower, LLC	LU		NA	NA	NA
9	Threemile Canyon Wind I, LLC	LU		NA	NA	NA
10	Top of The World Wind Energy LLC	LU		NA	NA	NA
11	TransAlta Energy Marketing (U.S.) Inc.	SF		NA	NA	NA
12	Tri-State Gen. & Trans.	LF		25	25	18
13	Tri-State Gen. & Trans.	SF		NA	NA	NA
14	Tuana Springs Energy, LLC	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)	
61,980				999,435	1,235	1,000,670	1
2,726				40,614		40,614	2
5,740				189,403		189,403	3
25,014				845,991		845,991	4
2,768			83,116	231,688		314,804	5
166,324				3,887,037		3,887,037	6
1,888			23,310	185,095		208,405	7
340,033				21,681,288		21,681,288	8
22,740				1,566,514		1,566,514	9
665,128				43,898,356		43,898,356	10
148,691				3,084,125		3,084,125	11
113,858			6,351,000	2,894,270		9,245,270	12
16,775				212,851	260,675	473,526	13
					77,340	77,340	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	Tucson Electric Power Company	SF		NA	NA	NA
2	UNS Electric, Inc.	SF		NA	NA	NA
3	US Magnesium LLC	LF		NA	NA	NA
4	US Magnesium LLC	LU		NA	NA	NA
5	United States Air Force at Hill Base	LU		NA	NA	NA
6	Wagon Trail, LLC	LU		NA	NA	NA
7	Ward Butte Windfarm, LLC	LU		NA	NA	NA
8	Warm Springs Forest Products	LU		NA	NA	NA
9	Wasatch Integrated Waste Management	AD		NA	NA	NA
10	Wasatch Integrated Waste Management	LU		NA	NA	NA
11	Weber County	LU		NA	NA	NA
12	Western Area Power Administration	LF		NA	NA	NA
13	Western Area Power Administration	SF		NA	NA	NA
14	Western Area Power Administration	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)	
24,050				668,593	13,531	682,124	1
41,144				1,169,883		1,169,883	2
					6,194,167	6,194,167	3
128,736				5,154,841		5,154,841	4
14,227				654,845		654,845	5
7,682				520,842		520,842	6
17,718				1,194,858		1,194,858	7
772				20,961		20,961	8
					-13,661	-13,661	9
948				32,530		32,530	10
5,022				238,529		238,529	11
7,065					215,517	215,517	12
18,750					532,255	532,255	13
5,006				82,720	52	82,772	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Wolverine Creek Energy, LLC	LU		NA	NA	NA
2	Yakima-Tieton Irrigation District	LU		1.6	1.2	1.0
3	Oregon Solar Incentive	AD		NA	NA	NA
4	Oregon Solar Incentive	LU		NA	NA	NA
5	Settlement/Reserves			NA	NA	NA
6	Netting - Trading			NA	NA	NA
7	Netting - Bookouts			NA	NA	NA
8	Net Power Cost Deferrals			NA	NA	NA
9	Accrual			NA	NA	NA
10						
11	Power Exchanges:					
12	Arizona Public Service Company	EX	307	NA	NA	NA
13	Avista Corporation	EX	554	NA	NA	NA
14	Basin Electric Power Cooperative	EX	T-11	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
178,431				10,027,514		10,027,514	1
6,864			17,281	251,416		268,697	2
447					18,454	18,454	3
3,551				111,774		111,774	4
					50,000	50,000	5
					-2,036,446	-2,036,446	6
-5,564,193					-177,742,246	-177,742,246	7
					-3,516,448	-3,516,448	8
					-1,715,009	-1,715,009	9
							10
							11
	570,868	571,392			948,211	948,211	12
	1,662						13
	9,598	174			217,190	217,190	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Black Hills Power, Inc.	EX	246	NA	NA	NA
2	Bonneville Power Administration	AD	256	NA	NA	NA
3	Bonneville Power Administration	AD	T-11	NA	NA	NA
4	Bonneville Power Administration	AD	T-12	NA	NA	NA
5	Bonneville Power Administration	AD	237	NA	NA	NA
6	Bonneville Power Administration	EX	237	NA	NA	NA
7	Bonneville Power Administration	EX	256	NA	NA	NA
8	Bonneville Power Administration	EX	368	NA	NA	NA
9	Bonneville Power Administration	EX	519	NA	NA	NA
10	Bonneville Power Administration	EX	554	NA	NA	NA
11	Bonneville Power Administration	EX		NA	NA	NA
12	Bonneville Power Administration	EX	T-11	NA	NA	NA
13	Bonneville Power Administration	EX	T-12	NA	NA	NA
14	City of Redding	EX	364	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)	
	12						1
		259			-7,770	-7,770	2
		32			-957	-957	3
	50				1,098	1,098	4
		1,120			-2,801	-2,801	5
		1,087			22,026	22,026	6
	942	942			-7,536	-7,536	7
	237,568	237,568					8
	94,224	100,008			-182,270	-182,270	9
	211,819	15,677					10
	8,995,977	8,995,977			-32,166,509	-32,166,509	11
	9,007	12,146			-63,545	-63,545	12
	24,848				713,697	713,697	13
	118,433	118,594			135,707	135,707	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Cyrg Energy	EX	T-11	NA	NA	NA
2	Deseret Generation & Transmission Coop	AD	280	NA	NA	NA
3	Deseret Generation & Transmission Coop	EX	21	NA	NA	NA
4	Deseret Generation & Transmission Coop	EX	280	NA	NA	NA
5	Emerald People's Utility District	EX	351	NA	NA	NA
6	Eugene Water & Electric Board	EX	T-12	NA	NA	NA
7	Iberdrola Renewables, LLC	EX	T-11	NA	NA	NA
8	Idaho Power Company	EX	380	NA	NA	NA
9	JP Morgan Ventures Energy Corporation	EX	T-11	NA	NA	NA
10	Los Angeles Dept. of Water & Power	EX	OV-1	NA	NA	NA
11	Milford Wind Corridor Phase I, LLC	EX	OV-1	NA	NA	NA
12	Milford Wind Corridor Phase II, LLC	EX	OV-1	NA	NA	NA
13	NextEra Energy Power Marketing, LLC	EX	T-11	NA	NA	NA
14	Noble Americas Energy Solutions LLC	EX	T-11	NA	NA	NA
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
	1,925	1,828			3,692	3,692	1
	18,360	-21,180			1,215,556	1,215,556	2
		8,516					3
	52,460	31,087			564,102	564,102	4
		516			-12,896	-12,896	5
	16,123	16,308			-7,628	-7,628	6
	6,601	4,754			46,174	46,174	7
	458,105	286,540					8
	1,850	1,154			14,167	14,167	9
	2,212				153,851	153,851	10
		1,263			-119,272	-119,272	11
		949			-76,099	-76,099	12
	94,624	64,756			569,623	569,623	13
	7,919	5,679			63,894	63,894	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Portland General Electric Company	EX	554	NA	NA	NA
2	Public Service Company of Colorado	EX	319	NA	NA	NA
3	Public Service Company of Colorado	EX	334	NA	NA	NA
4	Public Service Company of Colorado	EX	T-12	NA	NA	NA
5	PUD No. 1 of Cowlitz County	EX	554	NA	NA	NA
6	Seattle City Light	AD	554	NA	NA	NA
7	Seattle City Light	EX	554	NA	NA	NA
8	Southern California Edison Company	EX	T-11	NA	NA	NA
9	Southern California Public Power Auth.	EX	T-11	NA	NA	NA
10	Tri-State Gen. & Trans.	AD	319	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					

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)	
	131,521	130,520					1
	3,280						2
	1,316,441	1,313,022			5,400,000	5,400,000	3
	72,277	69,885			82,575	82,575	4
	237,832	298,583					5
		384					6
	384,214	365,189			421,517	421,517	7
	78,983	61,293			332,014	332,014	8
	1,887	1,249			14,316	14,316	9
					1,375	1,375	10
	3,280				-11,692	-11,692	11
	2,997	6,803			-66,805	-66,805	12
	380	-763			43,526	43,526	13
	98,610	68,884			941,455	941,455	14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

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	AD	T-11	NA	NA	NA
2	Utah Municipal Power Agency	EX	T-11	NA	NA	NA
3	Warm Springs Power Enterprises	EX	T-11	NA	NA	NA
4	Western Area Power Administration	AD	LAS-4	NA	NA	NA
5	Western Area Power Administration	EX	LAS-4	NA	NA	NA
6	System Deviation	NA		NA	NA	NA
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)	
	-862	-884			212	212	1
	21,839	13,988			276,814	276,814	2
	8,795	3,768			118,701	118,701	3
	53	2,350			-263,846	-263,846	4
	248	33,234			-571,991	-571,991	5
22,051							6
							7
							8
							9
							10
							11
							12
							13
							14
13,716,836	13,296,962	12,824,651	76,387,516	643,504,514	-184,305,753	535,586,277	

Schedule Page: 326 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326 Line No.: 3 Column: l
Line loss.

Schedule Page: 326 Line No.: 4 Column: b
Arizona Public Service Company - contract termination date: October 31, 2020

Schedule Page: 326 Line No.: 5 Column: l
Line loss.

Schedule Page: 326 Line No.: 6 Column: l
Reserve share.

Schedule Page: 326 Line No.: 8 Column: l
Financial swap.

Schedule Page: 326 Line No.: 9 Column: l
Financial swap.

Schedule Page: 326 Line No.: 11 Column: l
Financial swap.

Schedule Page: 326 Line No.: 13 Column: b
Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.1 Line No.: 2 Column: l
Non-generation agreement.

Schedule Page: 326.1 Line No.: 4 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.1 Line No.: 4 Column: k
PacifiCorp has entered into an agreement with RBS Asset Finance, Inc. to lease the Black Cap Solar generating facility. The lease has a 16-year term from October 2012 to October 2028 and is accounted for as an operating lease. This amount represents test energy purchased prior to the October 2012 effective date of the operating lease. For more information, refer to Important Changes During the Year, Item 4, in this FERC Form 1.

Schedule Page: 326.1 Line No.: 5 Column: b
Settlement adjustment.

Schedule Page: 326.1 Line No.: 5 Column: l
Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 6 Column: l
Operation and maintenance expense associated with the combustion turbine located in Rapid City, South Dakota.

Schedule Page: 326.1 Line No.: 8 Column: b
Blanding City Corporation - contract termination date: March 31, 2013

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: 326.2 Line No.: 2 Column: l
Variable operating, maintenance and fuel expense associated with gas facility located in West Valley, Utah.

Schedule Page: 326.2 Line No.: 3 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.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.2 Line No.: 3 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: l

Financial swap.

Schedule Page: 326.3 Line No.: 4 Column: b

City of Hurricane - contract termination date: August 31, 2017

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

This footnote applies to all occurrences of "City of Portland, Water Bureau" on pages 326-327. Complete name is City of Portland, Portland Water Bureau.

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

Financial swap.

Schedule Page: 326.3 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.3 Line No.: 13 Column: l

Settlement adjustment.

Schedule Page: 326.4 Line No.: 3 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.: 3 Column: b

Deseret Generation and Transmission Cooperative - contract termination date: September 30, 2024

Schedule Page: 326.4 Line No.: 3 Column: l

Reimbursement to counterparty for operation and maintenance costs at coal fired generating facility located in Vernal, Utah.

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

Financial swap.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.4 Line No.: 11 Column: l

Financial swap.

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

Line loss.

Schedule Page: 326.5 Line No.: 5 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.5 Line No.: 7 Column: b

Flathead Electric Cooperative, Inc. - contract termination date: September 30, 2016

Schedule Page: 326.5 Line No.: 7 Column: l

Line loss.

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

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.6 Line No.: 2 Column: b
Settlement adjustment.

Schedule Page: 326.6 Line No.: 2 Column: l
Settlement adjustment.

Schedule Page: 326.6 Line No.: 3 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 (b) of this Form No. 1 for further information on the Hermiston Generating Plant.

Schedule Page: 326.6 Line No.: 3 Column: l
On peak incentive, supplemental dispatch efficiency expense, start-up charges and committee settlements.

Schedule Page: 326.6 Line No.: 4 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.6 Line No.: 4 Column: l
Purchase of renewable energy credit certificates for Washington renewable portfolio standard requirements.

Schedule Page: 326.6 Line No.: 5 Column: l
Financial swap.

Schedule Page: 326.6 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 326.6 Line No.: 6 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.6 Line No.: 7 Column: l
Labor, equipment and administration fees associated with hydro project in Idaho Falls, Idaho.

Schedule Page: 326.6 Line No.: 8 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.6 Line No.: 9 Column: l
Reserve share.

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.: 14 Column: l
Financial swap.

Schedule Page: 326.7 Line No.: 1 Column: l
Surprise Valley Electrification Corp. - contract termination date: Evergreen

Schedule Page: 326.7 Line No.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.7 Line No.: 5 Column: l
Compensation for self-generation.

Schedule Page: 326.7 Line No.: 6 Column: l
Fixed annual payment.

Schedule Page: 326.7 Line No.: 7 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.: 7 Column: b
Settlement adjustment.

Schedule Page: 326.7 Line No.: 7 Column: l
Settlement adjustment.

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

Line loss.

Schedule Page: 326.7 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.7 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.7 Line No.: 13 Column: l

Financial swap.

Schedule Page: 326.8 Line No.: 4 Column: l

Compensation for interruptible service and operating reserves.

Schedule Page: 326.8 Line No.: 5 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.8 Line No.: 7 Column: l

Financial swap.

Schedule Page: 326.8 Line No.: 12 Column: l

Reserve share.

Schedule Page: 326.8 Line No.: 13 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.8 Line No.: 14 Column: l

Line loss.

Schedule Page: 326.9 Line No.: 4 Column: l

Reserve share.

Schedule Page: 326.9 Line No.: 5 Column: l

Ancillary services.

Schedule Page: 326.10 Line No.: 1 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 2 Column: l

Line loss.

Schedule Page: 326.10 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 3 Column: l

Operation expense plus amortization of unrecovered costs of Cove project.

Schedule Page: 326.10 Line No.: 4 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.: 4 Column: l

Operation expense plus amortization of unrecovered costs of Cove project.

Schedule Page: 326.10 Line No.: 5 Column: l

Reserve share.

Schedule Page: 326.10 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 6 Column: l

Settlement adjustment.

Schedule Page: 326.10 Line No.: 8 Column: b

Settlement adjustment.

Schedule Page: 326.10 Line No.: 8 Column: l

Settlement adjustment.

Schedule Page: 326.10 Line No.: 10 Column: l

Financial swap.

Schedule Page: 326.10 Line No.: 11 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.10 Line No.: 13 Column: l

Line loss.

Schedule Page: 326.10 Line No.: 14 Column: a
This footnote applies to all occurrences of "PUD No. 1 of Chelan County" on pages 326-327. Complete name is Public Utility District No. 1 of Chelan County.

Schedule Page: 326.10 Line No.: 14 Column: b
Settlement adjustment.

Schedule Page: 326.10 Line No.: 14 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 1 Column: l
Reserve share.

Schedule Page: 326.11 Line No.: 2 Column: a
This footnote applies to all occurrences of "PUD No. 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.: 2 Column: b
Secondary, economy and/or non-firm.

Schedule Page: 326.11 Line No.: 2 Column: l
Liability associated with paper pond at hydro facility located on the Lewis River in Washington.

Schedule Page: 326.11 Line No.: 3 Column: a
This footnote applies to all occurrences of "PUD No. 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.: 3 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 3 Column: l
Settlement adjustment.

Schedule Page: 326.11 Line No.: 4 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 4 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 5 Column: b
Public Utility District No. 1 of Douglas County - contract termination date: August 31, 2018

Schedule Page: 326.11 Line No.: 6 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 7 Column: l
Reserve share.

Schedule Page: 326.11 Line No.: 8 Column: a
This footnote applies to all occurrences of "PUD No. 1 of Snohomish County" on pages 326-327. Complete name is Public Utility District No. 1 of Snohomish County.

Schedule Page: 326.11 Line No.: 9 Column: a
This footnote applies to all occurrences of "PUD No. 2 of Grant County" on pages 326-327. Complete name is Public Utility District No. 2 of Grant County.

Schedule Page: 326.11 Line No.: 9 Column: b
Settlement adjustment.

Schedule Page: 326.11 Line No.: 9 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 10 Column: b
Public Utility District No. 2 of Grant County - contract termination date: August 15, 2012

Schedule Page: 326.11 Line No.: 10 Column: l
Ancillary services.

Schedule Page: 326.11 Line No.: 11 Column: l
Operating expense, bond interest, amortization and taxes.

Schedule Page: 326.11 Line No.: 12 Column: l
Reserve share.

Schedule Page: 326.11 Line No.: 13 Column: l

Reserve share.

Schedule Page: 326.12 Line No.: 5 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: 326.12 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 8 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.12 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.12 Line No.: 9 Column: l

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

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

Settlement adjustment.

Schedule Page: 326.13 Line No.: 1 Column: b

Sacramento Municipal Utility District - contract termination date: December 31, 2014

Schedule Page: 326.13 Line No.: 3 Column: l

Line loss.

Schedule Page: 326.13 Line No.: 7 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 7 Column: l

Settlement of Pacific Northwest Refund case.

Schedule Page: 326.13 Line No.: 8 Column: l

Reserve share.

Schedule Page: 326.13 Line No.: 10 Column: b

Settlement adjustment.

Schedule Page: 326.13 Line No.: 10 Column: l

Financial swap.

Schedule Page: 326.13 Line No.: 12 Column: l

Financial swap.

Schedule Page: 326.13 Line No.: 14 Column: l

Reserve share.

Schedule Page: 326.14 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.14 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.14 Line No.: 3 Column: l

Settlement adjustment.

Schedule Page: 326.14 Line No.: 10 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.14 Line No.: 12 Column: b

Under Electric Service Agreement subject to termination upon timely notification.

Schedule Page: 326.15 Line No.: 1 Column: l

Reserve share.

Schedule Page: 326.15 Line No.: 2 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 12 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: 326.15 Line No.: 12 Column: b

Tri-State Generation and Transmission Association, Inc. - contract termination date: December 31, 2020

Schedule Page: 326.15 Line No.: 13 Column: l

Line loss.

Schedule Page: 326.15 Line No.: 14 Column: b

Secondary, economy and/or non-firm.

Schedule Page: 326.15 Line No.: 14 Column: l

Purchase of renewable energy credit certificates for state of Washington renewable portfolio standard requirements.

Schedule Page: 326.16 Line No.: 1 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 3 Column: b

US Magnesium LLC - contract termination date: December 31, 2014

Schedule Page: 326.16 Line No.: 3 Column: l

Ancillary services.

Schedule Page: 326.16 Line No.: 5 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.: 9 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: 326.16 Line No.: 9 Column: b

Settlement adjustment.

Schedule Page: 326.16 Line No.: 9 Column: l

Settlement adjustment.

Schedule Page: 326.16 Line No.: 12 Column: b

Western Area Power Administration - contract termination date: May 31, 2022

Schedule Page: 326.16 Line No.: 12 Column: l

Westport Field Services, LLC - contract termination date: Evergreen

Schedule Page: 326.16 Line No.: 13 Column: l

Line loss.

Schedule Page: 326.16 Line No.: 14 Column: l

Reserve share.

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: l

Reserve for liabilities associated with the Pacific Northwest Refund case.

Schedule Page: 326.17 Line No.: 6 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.17 Line No.: 7 Column: l

Reflects transactions that did not physically settle.

Schedule Page: 326.17 Line No.: 8 Column: l

Deferrals and associated amortization under various energy cost adjustment mechanisms.

Schedule Page: 326.17 Line No.: 9 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, Purchased power, during this period.

Schedule Page: 326.17 Line No.: 12 Column: l

Exchange energy expense.

Schedule Page: 326.17 Line No.: 14 Column: l

Imbalance energy.

Schedule Page: 326.18 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.18 Line No.: 2 Column: l

Exchange energy expense.

Schedule Page: 326.18 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 326.18 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.18 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.18 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.18 Line No.: 5 Column: b

Settlement adjustment.

Schedule Page: 326.18 Line No.: 5 Column: l

Storage and exchange charges.

Schedule Page: 326.18 Line No.: 6 Column: l

Storage and exchange charges.

Schedule Page: 326.18 Line No.: 7 Column: l

Storage and exchange charges.

Schedule Page: 326.18 Line No.: 9 Column: l

Exchange energy expense.

Schedule Page: 326.18 Line No.: 11 Column: c

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.18 Line No.: 11 Column: h

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.18 Line No.: 11 Column: i

These megawatt hours represent book entry only. No actual energy transfer took place.

Schedule Page: 326.18 Line No.: 11 Column: l

Pacific Northwest Electric Power Planning and Conservation Act, FERC Electric Tariff, Original Volume No. 1.

Schedule Page: 326.18 Line No.: 12 Column: l

Imbalance energy.

Schedule Page: 326.18 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.18 Line No.: 14 Column: l

Exchange energy expense.

Schedule Page: 326.19 Line No.: 1 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 2 Column: b

Settlement adjustment.

Schedule Page: 326.19 Line No.: 2 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 5 Column: l

Storage and exchange charges.

Schedule Page: 326.19 Line No.: 6 Column: l

Exchange energy expense.

Schedule Page: 326.19 Line No.: 7 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 10 Column: l

Station service for third party wind project.

Schedule Page: 326.19 Line No.: 11 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.19 Line No.: 12 Column: l

Reimbursement for providing station service to third party wind project.

Schedule Page: 326.19 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.19 Line No.: 14 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 3 Column: l

Storage and exchange charges.

Schedule Page: 326.20 Line No.: 4 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 6 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 7 Column: l

Exchange energy expense.

Schedule Page: 326.20 Line No.: 8 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 9 Column: a

This footnote applies to all occurrences of "Southern California Public Power Auth." on pages 326-327. Complete name is Southern California Public Power Authority.

Schedule Page: 326.20 Line No.: 9 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 10 Column: b

Settlement adjustment.

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.: 12 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 13 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: 326.20 Line No.: 13 Column: b

Settlement adjustment.

Schedule Page: 326.20 Line No.: 13 Column: l

Imbalance energy.

Schedule Page: 326.20 Line No.: 14 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 1 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 1 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 2 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 3 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 4 Column: b

Settlement adjustment.

Schedule Page: 326.21 Line No.: 4 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 5 Column: l

Imbalance energy.

Schedule Page: 326.21 Line No.: 6 Column: b

Not applicable - adjustment for inadvertent interchange.

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

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Alpental Energy Partners, LLC	Alpental Energy Partners, LLC		LFP
2	Arizona Public Service Company	Arizona Public Service Company		OS
3	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	FNO
4	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	AD
5	Basin Electric Power Cooperative	Western Area Power Administration	Powder River Energy Corporation	SFP
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 Corporation	LFP
15	Black Hills Corporation		Black Hills Corporation	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 Electric & Columbia	FNO
26	Bonneville Power Administration	Bonneville Power Administration	Umatilla Electric & 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.
V11-7	South Milford Sub	Mona Substation	3			1
R.S. 436		Borah/Brady Sub				2
V11-1,2,3	Yellowtail Sub	Sheridan Substation		3,921	3,921	3
V11-3	Yellowtail Sub	Sheridan Substation	1	456	456	4
V11-1,2	Various	Various		50	50	5
V11-1,2	Various	Various		1,674	1,674	6
V11-1,2	Various	Various		381	381	7
V11-1,2	Various	Sheridan Substation	44	6,516	6,516	8
V11	Various	Sheridan Substation	44	2,732	2,732	9
V11-1,2,8	Various	Various		7,636	7,636	10
V11	Various	Various		24	24	11
V11-1,2,7	Various	Various		18,785	18,785	12
V11-7	Various	Various		522	522	13
V11-1,2,7	Various	Wyodak Substation	53	185,511	185,511	14
V11-7	Various	Wyodak Substation	50	14,039	14,039	15
R.S. 369	Midpoint Substation	Summer Lake Sub				16
R.S. 237	Various	Various	305	1,083,128	1,083,128	17
R.S. 237	Various	Various	322	121,322	121,322	18
V11-2,7	Lost Creek Hydro Plt	Alvey Substation	59	183,831	183,831	19
V11-7	Lost Creek Hydro Plt	Alvey Substation	56	15,731	15,731	20
V11-1,2,3,4	Bonneville Power Adm	Gazley Substation	3	23,452	23,452	21
V11 -3	Bonneville Power Adm	Gazley Substation	3	2,317	2,317	22
V11-1,2,3	Bonneville Power Adm	Tieton Substation	1	5,849	5,849	23
V11-3	Bonneville Power Adm	Tieton Substation	1	889	889	24
V11-1,2,3	McNary Substation	Hinkle Substation	1	999	999	25
V11-3	McNary Substation	Hinkle Substation	1	190	190	26
V11-2,7	USBR Green Springs	Bonneville Power Adm	19	62,636	62,636	27
V11-7	USBR Green Springs	Bonneville Power Adm	18	4,176	4,176	28
R.S. 368	Malin Substation	Malin Substation		511,114	511,114	29
R.S. 368	Malin Substation	Malin Substation		57,817	57,817	30
V11-1,2,3,4	Bonneville Power Adm	White Swan/Toppenish	5	32,223	32,223	31
V11-3,4	Bonneville Power Adm	White Swan/Toppenish	5	3,186	3,186	32
R.S. 299	Various	Various	214	1,011,575	1,011,575	33
R.S. 299	Various	Various	212	197,504	197,504	34
			4,227	**13,731,215**	**13,615,562**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		6,231	6,231	1
				2
7,827		13,805	21,632	3
		2,895	2,895	4
	149	11	160	5
	1,094	77	1,171	6
	192	14	206	7
1,003,007		71,111	1,074,118	8
		59,131	59,131	9
	15,755	1,090	16,845	10
		140	140	11
	73,979	5,522	79,501	12
		707	707	13
1,188,180		84,264	1,272,444	14
		101,250	101,250	15
				16
3,755,126		67,947	3,823,073	17
		349,970	349,970	18
1,330,762		61,446	1,392,208	19
		113,400	113,400	20
70,996		152,455	223,451	21
		16,882	16,882	22
14,738		3,444	18,182	23
		1,144	1,144	24
2,917		686	3,603	25
		248	248	26
427,745		19,751	447,496	27
		36,450	36,450	28
		246,944	246,944	29
		22,450	22,450	30
116,528		118,372	234,900	31
		14,982	14,982	32
886,376		1,024,573	1,910,949	33
		-64,126	-64,126	34
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			NF
2	Bonneville Power Administration			AD
3	Bonneville Power Administration			SFP
4	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	FNO
5	Bonneville Power Administration	Bonneville Power Administration	Clark Public Utilities	AD
6	Cargill Power Markets, LLC			NF
7	Cargill Power Markets, LLC			AD
8	Cargill Power Markets, LLC			SFP
9	Constellation Energy Commodities Group			NF
10	Constellation Energy Commodities Group			AD
11	Constellation Energy Commodities Group			SFP
12	Coral Power			NF
13	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	OS
14	Cowlitz County PUD	Cowlitz County PUD	Bonneville Power Administration	AD
15	Cyrq Energy, Inc.			LFP
16	Cyrq Energy, Inc.			AD
17	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
18	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
19	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	OS
20	Deseret Generation & Trans.	Deseret Generation & Trans.	Deseret Generation & Trans.	AD
21	EDF Trading North America, LLC			NF
22	EDF Trading North America, LLC			SFP
23	Eugene Water & Electric Board			NF
24	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	OS
25	Fall River Rural Electric Cooperative	Marysville Hydro Partners	Idaho Power Company	AD
26	Foote Creek III, LLC	Foote Creek III, LLC		OS
27	Foote Creek III, LLC	Foote Creek III, LLC		AD
28	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	LFP
29	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	LFP
30	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	LFP
31	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	LFP
32	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC	LFP
33	Iberdrola Renewables, LLC			NF
34	Iberdrola Renewables, LLC			AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
V11-1,2,8	Various	Various		2,100	2,100	1
V11-8	Various	Various		3	3	2
V11-1,2,7	Various	Various		299	299	3
V11-1,2,3,4	Cardwell-Merwin		16	108,019	108,019	4
V11-3,4	Cardwell-Merwin		19	15,255	15,255	5
V11-1,2,3,8	Various	Various		206,647	206,647	6
V11-8	Various	Various				7
V11-1,2,7	Various	Various		4,695	4,695	8
V11-1-3,5-8	Various	Various		95,346	95,346	9
V11-8	Various	Various		18,403	18,403	10
V11-1,2,3,5,6,7	Various	Various				11
V11-1-3,8	Various	Various		6,059	6,059	12
R.S. 234	Swift Unit No. 2	Woodland Substation				13
R.S. 234	Swift Unit No. 2	Woodland Substation				14
V11-1-3,5-7,9	South Milford Sub	Mona Substation	12	42,383	42,383	15
V11-5,6,7	South Milford Sub	Mona Substation	11	4,482	4,482	16
R.S. 280	Various	Various	90	706,217	706,217	17
R.S. 280	Various	Various	93	48,600	48,600	18
R.S. 590	Various	Various				19
R.S. 590	Various	Various				20
V11-1,2,8	Various	Various		1,908	1,908	21
V11-1,2,7	Various	Various		400	400	22
V11-1,2,8	Various	Various		8	8	23
R.S. 322	Targhee Substation	Goshen Substation		22,332	22,332	24
R.S. 322	Targhee Substation	Goshen Substation		2,907	2,907	25
S.A. 130	Foote Creek Sub	Various				26
S.A. 130	Foote Creek Sub	Various				27
V11-7	Malin 500 Substation	Round Mountain Sub	12			28
V11-7	Malin 500 Substation	Round Mountain Sub	38			29
V11-7	Malin 500 Substation	Round Mountain Sub	37			30
V11-7	Malin 500 Substation	Round Mountain Sub	37			31
V11-7	Lakeview Substation	Round Mountain Sub	26			32
V11-1,2,8,9,11	Various	Various		230,440	230,440	33
V11-8,9,11	Various	Various		132	132	34
			4,227	**13,731,215**	**13,615,562**	

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.
	37,989	2,782	40,771	1
		18	18	2
	1,830	130	1,960	3
359,396		85,959	445,355	4
		28,197	28,197	5
	1,139,620	78,540	1,218,160	6
		2,025	2,025	7
	26,970	1,784	28,754	8
	3,005	239,718	242,723	9
		7,761	7,761	10
	83	31	114	11
	34,802	2,770	37,572	12
		109,498	109,498	13
		9,869	9,869	14
261,400		97,592	358,992	15
		25,623	25,623	16
2,078,706		1,263,750	3,342,456	17
		229,243	229,243	18
		136,753	136,753	19
		142,733	142,733	20
	17,688	1,256	18,944	21
	9,975	630	10,605	22
	27	2	29	23
		138,699	138,699	24
		12,609	12,609	25
		33,167	33,167	26
		3,015	3,015	27
		24,300	24,300	28
		76,950	76,950	29
		74,925	74,925	30
		74,925	74,925	31
		52,650	52,650	32
	1,993,957	237,974	2,231,931	33
		2,969	2,969	34
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

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, LLC	Iberdrola Renewables, LLC		OS
2	Iberdrola Renewables, LLC	Iberdrola Renewables, LLC		AD
3	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	LFP
4	Iberdrola Renewables, LLC	Exxon Mobil	Nevada Power Company	AD
5	Idaho Power Company	Idaho Power Company	Idaho Power Company	OS
6	Idaho Power Company			OS
7	Idaho Power Company			AD
8	Idaho Power Company			OS
9	Idaho Power Company			AD
10	Idaho Power Company			NF
11	Idaho Power Company			AD
12	Idaho Power Company			SFP
13	Idaho Power Company	Exxon Mobil	Nevada Power Company	LFP
14	JP Morgan Ventures Energy Corp.			NF
15	JP Morgan Ventures Energy Corp.			AD
16	JP Morgan Ventures Energy Corp.			SFP
17	Los Angeles Dept of Water & Power			NF
18	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	OS
19	Moon Lake Electric Association	Moon Lake Electric Association	Moon Lake Electric Association	AD
20	Morgan Stanley Capital Group, Inc.			NF
21	Morgan Stanley Capital Group, Inc.			AD
22	Morgan Stanley Capital Group, Inc.			SFP
23	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	LFP
24	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	AD
25	NextEra Energy Resources, LLC	NextEra Energy Resources, LLC	Grant County PUD	NF
26	NextEra Energy Resources, LLC			AD
27	Nevada Power Company			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	NextEra Energy Resources, LLC	Grant County PUD	NF
33	Pacific Gas & Electric Company			OS
34	Portland General Electric Company			OS
	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.
V11-5,6						1
V11-5,6						2
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	32	70,563	70,563	3
V11-7	Trona Substation	Red Butte/Mona Sub	30	7,303	7,303	4
R.S. 427	Goshen Substation	Goshen Substation				5
R.S. 257	Antelope Substation	Antelope Substation		181,868	181,868	6
R.S. 257	Antelope Substation	Antelope Substation		22,638	22,638	7
R.S. 203	Jim Bridger Sub	Bridger Pump Sub		29,746	29,746	8
R.S. 203	Jim Bridger Sub	Bridger Pump Sub				9
V11-1,2,8	Various	Various		51,784	51,784	10
V11-8	Various	Various		905	905	11
V11-1,2,7	Various	Various		7,438	7,438	12
V11-1,2,7	Trona Substation	Red Butte/Mona Sub	79	25,450	25,450	13
V11-1,2,3,8,9	Various	Various		71,193	71,193	14
V11-8,9	Various	Various		3,474	3,474	15
V11-1,2,7	Various	Various		25	25	16
V11-1,2,8	Various	Various		5,392	5,392	17
R.S. 302	Duchesne	Duchesne	3	18,808	18,808	18
R.S. 302	Duchesne	Duchesne	3	1,598	1,598	19
V11-1,2,3,8	Various	Various		147,443	147,443	20
V11-8	Various	Various		12,455	12,455	21
V11-1,2,7	Various	Various		25,458	25,458	22
	Wallula Substation	Wala-MIDC Path	84	157,291	157,291	23
V11-5,6,7,9,11	Wallula Substation	Wala-MIDC Path	80	58	58	24
V11-1,2,3,8	Various	Various		647	647	25
V11-8	Various	Various				26
V11-8	Various	Various				27
V11-1,2,3,4	Bonneville Power Adm	Various	27	189,509	189,509	28
V11-1,2,3,4	Bonneville Power Adm	Various	12	7,692	7,692	29
R.S. 607						30
R.S. 607						31
V11-1,2,8	Various	Various		34	34	32
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				33
R.S. 137	Dalreed Substation	Dalreed Substation				34
			4,227	**13,731,215**	**13,615,562**	

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.
		233,786	233,786	1
		17,152	17,152	2
712,908		50,559	763,467	3
		60,750	60,750	4
				5
		67,672	67,672	6
		6,152	6,152	7
		14,927	14,927	8
		1,357	1,357	9
	297,962	19,934	317,896	10
		5,928	5,928	11
	75,800	5,210	81,010	12
807,975		57,094	865,069	13
	882,574	207,165	1,089,739	14
		81,088	81,088	15
	155	11	166	16
	47,297	3,050	50,347	17
		19,576	19,576	18
		1,845	1,845	19
	838,951	59,804	898,755	20
		62,766	62,766	21
	430,714	16,575	447,289	22
1,504,251		1,486,098	2,990,349	23
		189,325	189,325	24
	29,276	5,924	35,200	25
		7,493	7,493	26
		6	6	27
341,913		86,883	428,796	28
		10,199	10,199	29
		15,125,000	15,125,000	30
		1,375,000	1,375,000	31
	488	34	522	32
		284,922	284,922	33
		3,314	3,314	34
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

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

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	OS
2	Powder River Energy Corporation	Western Area Power Administration	Sheridan-Johnson Rural Elect.	AD
3	Powerex Corporation	Bonneville Power Administration	CAISO	LFP
4	Powerex Corporation	Bonneville Power Administration	CAISO	AD
5	Powerex Corporation	Powerex Corporation	CAISO	LFP
6	Powerex Corporation	Powerex Corporation	CAISO	LFP
7	Powerex Corporation	Powerex Corporation	CAISO	LFP
8	Powerex Corporation			NF
9	Powerex Corporation			AD
10	Powerex Corporation			SFP
11	PPL Energy Plus, LLC			NF
12	PPL Energy Plus, LLC			AD
13	PPL Energy Plus, LLC			SFP
14	Puget Sound P&L			AD
15	Rainbow Energy Marketing Corporation			NF
16	Rainbow Energy Marketing Corporation			SFP
17	Sacramento Municipal Utility District			LFP
18	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	LFP
19	Seattle City Light	FPL Energy Vansycle, LLC	Grant County PUD	AD
20	Sierra Pacific Power Company d/b/a NV			OS
21	Sierra Pacific Power Company d/b/a NV			AD
22	Sierra Pacific Power Company d/b/a NV			NF
23	Sierra Pacific Power Company d/b/a NV			SFP
24	Southern California Edison Company			SFP
25	Southern California Edison Company			AD
26	Southern California Edison Company			NF
27	Southern California Edison Company			AD
28	Southern California Edison Company			OS
29	Southern California Public Power	Powerex Corporation	Southern California Public Power	OS
30	State of South Dakota	Western Area Power Administration	Black Hills Corporation	LFP
31	State of South Dakota	Western Area Power Administration	Black Hills Corporation	AD
32	Tenaska Power Services Co.			NF
33	Tenaska Power Services Co.			SFP
34	The Energy Authority, Inc.			NF
	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. 123	Various	Buffalo Substation				1
R.S. 123	Various	Buffalo Substation				2
V11-1,2,7	Bonneville Power Adm	CRAG View Substation	84	425,204	425,204	3
V11-7	Bonneville Power Adm	CRAG View Substation	80	14,453	14,453	4
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			5
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			6
V11-1,7	Malin 500 Substation	Round Mountain Sub	50			7
V11-1,2,8	Various	Various		1,114,384	1,114,384	8
V11-8	Various	Various		1,546	1,546	9
V11-1,2,7	Various	Various		116,395	116,395	10
V11-1,2,8	Various	Various		4,906	4,906	11
V11-8	Various	Various		40	40	12
V11-1,2,7	Various	Various		935	935	13
V11-8	Various	Various				14
V11-1,2,8	Various	Various		39,492	39,492	15
V11-1,2,7	Various	Various		6,346	6,346	16
V11-7			60			17
V11-1,2,3,5,6,7	Wallula Substation	Wala-MIDC Path	6			18
V11-5,6,7,9	Wallula Substation	Wala-MIDC Path	25	2,638	2,638	19
R.S. 674	Sigurd Substation	Utah-Nevada Border				20
R.S. 674	Sigurd Substation	Utah-Nevada Border				21
V11-1,2,8	Various	Various		8,150	8,150	22
V11-1,2,7	Various	Various		11,304	11,304	23
V11-1-3,5-7	Various	Various		46,852	46,852	24
V11-5,6,7	Various	Various		9,030	9,030	25
V11-1-3,8,9,11	Various	Various		235,094	235,094	26
V11-8,9	Various	Various		9,791	9,791	27
R.S. 298	Sigurd-Glen Canyon	Pinto-Four Corners				28
V11-9,11	Tieton Substation	Various		322	322	29
V11-1,2,7	Yellowtail Sub	Wyodak Substation	4	18,209	18,209	30
V11-7	Yellowtail Sub	Wyodak Substation	4	1,638	1,638	31
V11-1,2,8	Various	Various		14,272	14,272	32
V11-1-2, 3-6,7	Various	Various		13,478	13,478	33
V11-1,2,8	Various	Various		1,219	1,219	34
			4,227	**13,731,215**	**13,615,562**	

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.
		327	327	1
		30	30	2
1,902,096		24,075	1,926,171	3
		162,000	162,000	4
822,000		39,200	861,200	5
822,000		39,200	861,200	6
822,000		39,200	861,200	7
	5,295,812	379,752	5,675,564	8
		18,086	18,086	9
	1,780,677	102,420	1,883,097	10
	26,698	1,871	28,569	11
		234	234	12
	4,760	337	5,097	13
		6	6	14
	156,668	10,561	167,229	15
	30,566	1,986	32,552	16
		121,500	121,500	17
26,006		9,664	35,670	18
		54,044	54,044	19
		68,919	68,919	20
		6,265	6,265	21
	46,434	3,222	49,656	22
	49,237	3,250	52,487	23
	412,294	155,680	567,974	24
		106,861	106,861	25
	1,519,940	621,721	2,141,661	26
		87,854	87,854	27
		284,922	284,922	28
		14,922	14,922	29
95,054		6,741	101,795	30
		8,100	8,100	31
	69,220	4,582	73,802	32
	54,710	4,085	58,795	33
	4,317	306	4,623	34
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	TransAlta Energy Marketing			NF
2	TransAlta Energy Marketing			AD
3	Tri-State Generation & Trans.		Tri-State Generation & Trans.	OS
4	Tri-State Generation & Trans.		Tri-State Generation & Trans	AD
5	Tri-State Generation & Trans.		Tri-State Generation & Trans.	FNO
6	Tri-State Generation & Trans.		Tri-State Generation & Trans	AD
7	Tri-State Generation & Trans.			NF
8	Tri-State Generation & Trans.			AD
9	Tri-State Generation & Trans.			SFP
10	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	FNO
11	U.S. Bureau of Reclamation	Bonneville Power Administration	U.S. Bureau of Reclamation	AD
12	U.S. Bureau of Reclamation	Bonneville Power Administration	Crooked River Irrigation District	OS
13	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	OS
14	U.S. Bureau of Reclamation	Western Area Power Administration	Weber Basin Water Conserv.	AD
15	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	OS
16	Utah Associated Municipal Power	Utah Associated Municipal Power	Utah Associated Municipal Power	AD
17	Utah Associated Municipal Power			NF
18	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	OS
19	Utah Municipal Power Agency	Utah Municipal Power Agency	Utah Municipal Power Agency	AD
20	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	OS
21	Warm Springs Power Enterprises	Warm Springs Power Enterprises	Portland General Electric	AD
22	Western Area Power Administration	Western Area Power Administration		OS
23	Western Area Power Administration	Western Area Power Administration		AD
24	Western Area Power Administration	Western Area Power Administration		OS
25	Western Area Power Administration	Western Area Power Administration		AD
26	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		NF
27	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		SFP
28	Western Area Power Adm. CO MO	Western Area Power Adm. CO MO		AD
29	Western Area Power Administration	Western Area Power Administration		OS
30	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	FNO
31	Western Area Power Administration	Western Area Power Administration	Western Area Power Administration	AD
32	Western Area Power Adm. CO River	Western Area Power Adm. CO River		NF
33	Western Area Power Adm. CO River	Western Area Power Adm. CO River		AD
34	Yakima-Tieton Irrigation District	Yakima-Tieton Irrigation District	Yakima-Tieton Irrigation District	LFP
	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)	MegaWatt Hours Delivered (j)	Line No.
V11-1,2,8	Various	Various		26,103	26,103	1
V11-8	Various	Various		339	339	2
R.S. 123	Various	Various	36	158,202	158,202	3
R.S. 123	Various	Various	38	15,952	15,952	4
V11-1,2,3,4	Dave Johnston Sub	Thermopolis Sub	9	65,771	65,771	5
V11-3,4	Dave Johnston Sub	Thermopolis Sub	17	350	350	6
V11-1,2,8	Various	Various		44,066	44,066	7
V11-8	Various	Various		20	20	8
V11-1,2,7	Various	Various		1,773	1,773	9
V11-1,2,3	Walla Walla Sub	Burbank Pumps	1	2,198	2,198	10
V11-3	Walla Walla Sub	Burbank Pumps	1	3	3	11
R.S. 67	Redmond Substation	Crooked River Pumps	7	9,819	9,819	12
R.S. 286	Various	Various		20,488	20,488	13
R.S. 286	Various	Various		986	986	14
R.S. 297	Various	Various	348	2,219,634	2,219,634	15
R.S. 297	Various	Various	317	156,293	156,293	16
V11-1,2,3,8	Various	Various		8,716	8,716	17
R.S. 637	Various	Various	113	541,292	541,292	18
R.S. 637	Various	Various	100	44,850	44,850	19
R.S. 591	Pelton Reregulating	Round Butte Sub		84,469	84,469	20
R.S. 591	Pelton Reregulating	Round Butte Sub		7,872	7,872	21
R.S. 262	Various	Various	330	1,682,325	1,582,726	22
R.S. 262	Various	Various	330	208,005	195,920	23
R.S. 263	Various	Various		86,344	81,078	24
R.S. 263	Various	Various		13,902	13,112	25
V11-1,2,8	Various	Various		9,765	9,765	26
V11-1,2,7	Various	Various		30,405	30,405	27
7V11-7	Various	Various		3,988	3,988	28
R.S. 664	Dave Johnston Sub	Various				29
V11-1,2	Wyoming Distribution	Wyoming Distribution	2	12,299	12,299	30
V11	Wyoming Distribution	Wyoming Distribution	1	2	2	31
V11-1,2,8	Various	Various		198	198	32
V11-8	Various	Various		2	2	33
V11-7	Tieton-MidC Path	Enterprise	3			34
			4,227	**13,731,215**	**13,615,562**	

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.
	169,450	11,686	181,136	1
		2,272	2,272	2
124,763			124,763	3
		13,541	13,541	4
197,065		56,209	253,274	5
		29,491	29,491	6
	214,033	13,787	227,820	7
		117	117	8
	18,466	1,272	19,738	9
7,159		11,966	19,125	10
		1,189	1,189	11
11,319			11,319	12
		23,815	23,815	13
		1,839	1,839	14
7,305,957		1,253,324	8,559,281	15
		592,202	592,202	16
	46,941	10,569	57,510	17
2,439,363		558,570	2,997,933	18
		185,170	185,170	19
		109,725	109,725	20
		9,975	9,975	21
1,973,539		550,000	2,523,539	22
		230,167	230,167	23
		53,320	53,320	24
		7,722	7,722	25
	43,149	2,826	45,975	26
	114,976	7,771	122,747	27
		19,530	19,530	28
				29
37,465		51,687	89,152	30
		5,099	5,099	31
	1,199	86	1,285	32
		140	140	33
		6,075	6,075	34
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

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

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
				63,493	65,580	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
			4,227	**13,731,215**	**13,615,562**	

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.
		-2,561,996	-2,561,996	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
31,456,537	**16,019,879**	**28,939,781**	**76,416,197**	

Schedule Page: 328 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 1 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 669) terminating on December 31, 2032. Customer subsequently terminated contract effective May 29, 2012.

Schedule Page: 328 Line No.: 1 Column: m
Extension of commencement date fee.

Schedule Page: 328 Line No.: 2 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 2 Column: d
Legacy contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates October 31, 2020. See also page 332, Transmission of electricity by others, of this Form No. 1.

Schedule Page: 328 Line No.: 2 Column: f
Glen Canyon/Four Corners Substation.

Schedule Page: 328 Line No.: 3 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505) terminating no earlier than 12 months from notice by the customer.

Schedule Page: 328 Line No.: 3 Column: m
Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 4 Column: d
Network transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 505) terminating no earlier than 12 months from notice by the customer.

Schedule Page: 328 Line No.: 4 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. December 2011 service.

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.: 5 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328 Line No.: 6 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328 Line No.: 6 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 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.: 7 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 (2nd Revised Service Agreement 347) terminating on December 31, 2017.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 (2nd Revised Service Agreement 347) terminating on December 31, 2017.

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

December 2011 service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 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

December 2011 service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 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.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

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

Various signatories to the 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 2011 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 (2nd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 14 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 (2nd Revised Service Agreement 67) terminating on December 31, 2023.

Schedule Page: 328 Line No.: 15 Column: m

December 2011 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 ("BPA") 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 page 332, Transmission of electricity by others, of this Form No. 1.

Schedule Page: 328 Line No.: 17 Column: d

Legacy contract (2nd Revised Rate Schedule 237) executed between PacifiCorp and 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 or facilities charge.

Schedule Page: 328 Line No.: 18 Column: d

Legacy contract (2nd Revised Rate Schedule 237) executed between PacifiCorp and 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 or facilities charge. December 2011 service.

Schedule Page: 328 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 19 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 20 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 656) terminating on August 31, 2030.

Schedule Page: 328 Line No.: 20 Column: m

December 2011 service.

Schedule Page: 328 Line No.: 21 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th 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. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 22 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (6th 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 service. December 2011 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 service and distribution delivery service under the Open Access Transmission Tariff (1st Revised Service Agreement 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 23 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 24 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (1st Revised Service Agreement 539) terminating on November 30, 2013.

Schedule Page: 328 Line No.: 24 Column: m

Regulation and frequency response service. December 2011 service.

Schedule Page: 328 Line No.: 25 Column: c

This footnote applies to all occurrences of "Umatilla Electric & Columbia" on pages 328 - 330. Complete name is Umatilla Electric Cooperative Association and Columbia Basin Electric Cooperative, Inc.

Schedule Page: 328 Line No.: 25 Column: d

Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 25 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 26 Column: d

Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 538) terminating on December 31, 2013.

Schedule Page: 328 Line No.: 26 Column: m

Regulation and frequency response service. December 2011 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 (2nd Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 27 Column: m

Reactive supply and voltage control service.

Schedule Page: 328 Line No.: 28 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 179) terminating on September 30, 2025.

Schedule Page: 328 Line No.: 28 Column: m

December 2011 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 2011 service.

Schedule Page: 328 Line No.: 31 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (4th Revised Service Agreement 328) terminated on June 25, 2022.

Schedule Page: 328 Line No.: 31 Column: m

Distribution voltage service charge. Primary delivery service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328 Line No.: 32 Column: d

Network transmission service and distribution delivery service under the Open Access Transmission Tariff (4th Revised Service Agreement 328) terminated on June 25, 2022.

Schedule Page: 328 Line No.: 32 Column: m

Distribution voltage service charge. Primary delivery service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Regulation and frequency response service. December 2011 service.

Schedule Page: 328 Line No.: 33 Column: d

Legacy contract (1st Revised Rate Schedule 299) executed between PacifiCorp and 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 or 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 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 or facilities charge. Charges for scheduling and operating reserves. Refunds of transmission service covering prior years. December 2011 service.

Schedule Page: 328.1 Line No.: 1 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 1 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 2 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 2 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 2 Column: m

December 2011 service.

Schedule Page: 328.1 Line No.: 3 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 3 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 4 Column: d

Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 370) terminated on December 7, 2012.

Schedule Page: 328.1 Line No.: 4 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 4 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.1 Line No.: 5 Column: d

Network transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 370) terminated on December 7, 2012.

Schedule Page: 328.1 Line No.: 5 Column: g

Chelatchie/View 115kV

Schedule Page: 328.1 Line No.: 5 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9. Regulation and frequency response service. December 2011 service.

Schedule Page: 328.1 Line No.: 6 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 6 Column: c

Various signatories to the 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.1 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 7 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 7 Column: m
December 2011 service.

Schedule Page: 328.1 Line No.: 8 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 8 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 8 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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 Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 9 Column: c
Various signatories to the 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
Transmission resales, purchase of point-to-point transmission. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 10 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 10 Column: c
Various signatories to the 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
Transmission resales, purchase of point-to-point transmission. December 2011 service.

Schedule Page: 328.1 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 11 Column: c
Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 12 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 12 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 12 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.1 Line No.: 13 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.: 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.

Schedule Page: 328.1 Line No.: 14 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.: 14 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 2011 service.

Schedule Page: 328.1 Line No.: 15 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 15 Column: c

Various signatories to the 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 (2nd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.1 Line No.: 15 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 16 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 16 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 16 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (2nd Revised Service Agreement 568) terminating on April 30, 2029.

Schedule Page: 328.1 Line No.: 16 Column: m

Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service. December 2011 service.

Schedule Page: 328.1 Line No.: 17 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.: 17 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (5th 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

Meter interrogation services. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.1 Line No.: 18 Column: d

Legacy contract executed between PacifiCorp and Deseret Generation and Transmission Co-operative for transmission service over agreed-upon facilities (5th Amended and Restated Transmission Service and Operating Agreement, Rate Schedule 280). Agreement subject to termination upon mutual agreement.

Schedule Page: 328.1 Line No.: 18 Column: m

Scheduling and load following charges. Distribution voltage service charge. Charges for spinning and/or supplemental reserves. December 2011 service.

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 on January 31, 2012.

Schedule Page: 328.1 Line No.: 19 Column: m

Charges for spinning and/or supplemental reserves. Regulation and frequency response. Meter interrogation service. Charges for control area services.

Schedule Page: 328.1 Line No.: 20 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 on January 31, 2012.

Schedule Page: 328.1 Line No.: 20 Column: m

Charges for spinning and/or supplemental reserves. Regulation and frequency response. Meter interrogation service. Charges for control area services. December 2011 service.

Schedule Page: 328.1 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 21 Column: c

Various signatories to the 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.: 21 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.1 Line No.: 22 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 22 Column: c
Various signatories to the 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.: 22 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.1 Line No.: 23 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 23 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.1 Line No.: 23 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.1 Line No.: 23 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.1 Line No.: 24 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.: 24 Column: m
Sole use of facilities charge based on a capacity factor and/or proportional use as defined in the contract. Customer capacity is 10 megawatts ("MW").
Schedule Page: 328.1 Line No.: 25 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.: 25 Column: m
Sole use of facilities charge based on a capacity factor and/or proportional use as defined in the contract. Customer capacity is 10 MW. December 2011 service.
Schedule Page: 328.1 Line No.: 26 Column: c
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.
Schedule Page: 328.1 Line No.: 26 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.: 26 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.: 27 Column: c
PacifiCorp Energy, a business unit of PacifiCorp responsible for electric generation and commodity trading activities.
Schedule Page: 328.1 Line No.: 27 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.: 27 Column: m
Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2011 service.
Schedule Page: 328.1 Line No.: 28 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 653) deferred until January 1, 2013 and terminating on December 31, 2017.

Schedule Page: 328.1 Line No.: 28 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 29 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 697) deferred until January 1, 2013 and terminating on December 31, 2017.

Schedule Page: 328.1 Line No.: 29 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 30 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 698) deferred until January 1, 2013 and terminating on December 31, 2017.

Schedule Page: 328.1 Line No.: 30 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 31 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 699) deferred until January 1, 2013 and terminating on December 31, 2017.

Schedule Page: 328.1 Line No.: 31 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 32 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 655) deferred until January 1, 2013 and terminating on December 31, 2017.

Schedule Page: 328.1 Line No.: 32 Column: m

Extension of commencement date fee.

Schedule Page: 328.1 Line No.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 33 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 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: 328.1 Line No.: 33 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.1 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.1 Line No.: 34 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.1 Line No.: 34 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2011 service.

Schedule Page: 328.2 Line No.: 1 Column: c

Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems.

Schedule Page: 328.2 Line No.: 1 Column: d

Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.2 Line No.: 1 Column: f

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.2 Line No.: 1 Column: g

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.2 Line No.: 1 Column: m

Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 2 Column: c

Iberdrola Renewables, LLC and Utah Associated Municipal Power Systems.

Schedule Page: 328.2 Line No.: 2 Column: d

Ancillary services under the Open Access Transmission Tariff (1st Revised Service Agreement 476) in effect until superseded.

Schedule Page: 328.2 Line No.: 2 Column: f

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.2 Line No.: 2 Column: g

Long Hollow, Wyoming Switching Station.

Schedule Page: 328.2 Line No.: 2 Column: m

Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service. December 2011 service.

Schedule Page: 328.2 Line No.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 279) terminating on April 30, 2014.

Schedule Page: 328.2 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 279) terminating on April 30, 2014.

Schedule Page: 328.2 Line No.: 4 Column: m

December 2011 service.

Schedule Page: 328.2 Line No.: 5 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 page 332, Transmission of electricity by others, of this Form No. 1.

Schedule Page: 328.2 Line No.: 6 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 6 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/United States Department of Energy Supply Agreement.

Schedule Page: 328.2 Line No.: 6 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.: 7 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 7 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/United States Department of Energy Supply Agreement.

Schedule Page: 328.2 Line No.: 7 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2011 service.

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 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 Bridger Pump Substation. Agreement terminates upon 12 months written notice.

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 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 Bridger Pump Substation. Agreement terminates upon 12 months written notice.

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 2011 service.

Schedule Page: 328.2 Line No.: 10 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 10 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 10 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 11 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 11 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 11 Column: m

December 2011 service.

Schedule Page: 328.2 Line No.: 12 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 12 Column: c

Various signatories to the 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 13 Column: d
Point-to-point transmission service under the Open Access Transmission Tariff (6th Revised Service Agreement 212) terminating on May 31, 2014.

Schedule Page: 328.2 Line No.: 13 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 14 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.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 14 Column: c
Various signatories to the 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.: 14 Column: m
Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 15 Column: c
Various signatories to the 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
Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2011 service.

Schedule Page: 328.2 Line No.: 16 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 16 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 16 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 16 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 17 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.: 17 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 17 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 17 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

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, 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.

Schedule Page: 328.2 Line No.: 19 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, by providing two years' written notice.

Schedule Page: 328.2 Line No.: 19 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 2011 service.

Schedule Page: 328.2 Line No.: 20 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 20 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 21 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 21 Column: c

Various signatories to the 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

December 2011 service.

Schedule Page: 328.2 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 22 Column: c

Various signatories to the 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.: 22 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 23 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.: 23 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (Service Agreement 626) assignment from Seattle City Light, terminated 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.: 23 Column: e

V11-1-3,5-7,9,11

Schedule Page: 328.2 Line No.: 23 Column: m

Transmission resales, amount paid by seller. Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

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, terminated 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

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Transmission resales, amount paid by seller for December 2011 service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.2 Line No.: 25 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 25 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.2 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 26 Column: c

Various signatories to the 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.: 26 Column: m

December 2011 service.

Schedule Page: 328.2 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.2 Line No.: 27 Column: c

Various signatories to the 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 2011 service.

Schedule Page: 328.2 Line No.: 28 Column: d

Transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 299). Service provided pursuant to rules and 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

Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.2 Line No.: 29 Column: d

Transmission service under the Open Access Transmission Tariff (4th Revised Service Agreement 299). Service provided pursuant to rules and 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

December 2011 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 on 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 on 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 2011 service.

Schedule Page: 328.2 Line No.: 32 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.2 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.2 Line No.: 33 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 33 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 33 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 kilovolt ("kV")transmission line and Pinto-Four Corners 345-kV transmission line). Terminating on February 12, 2020.

Schedule Page: 328.2 Line No.: 33 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.: 34 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 34 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.2 Line No.: 34 Column: d

Legacy contract (Rate Schedule 137) executed between PacifiCorp and Portland General Electric for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge for the Dalreed Substation terminating on December 12, 2012.

Schedule Page: 328.2 Line No.: 34 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.: 1 Column: c

This footnote applies to all occurrences of "Sheridan-Johnson Rural Elect." on pages 328 - 330. Complete name is Sheridan-Johnson Rural Electric Association.

Schedule Page: 328.3 Line No.: 1 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.: 1 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.: 2 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.: 2 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2011 service.

Schedule Page: 328.3 Line No.: 3 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.: 3 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 3 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 4 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (7th Revised Service Agreement 169) terminating on October 31, 2020.

Schedule Page: 328.3 Line No.: 4 Column: m

December 2011 service.

Schedule Page: 328.3 Line No.: 5 Column: d

Point-to-point transmission service the Open Access Transmission Tariff (1st Revised Service Agreement 701) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 5 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 6 Column: d

Point-to-point transmission service the Open Access Transmission Tariff (1st Revised Service Agreement 702) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 6 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 7 Column: d
Point-to-point transmission service the Open Access Transmission Tariff (1st Revised Service Agreement 703) terminating on March 31, 2017.

Schedule Page: 328.3 Line No.: 7 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 8 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 8 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 8 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 9 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 9 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 9 Column: m
December 2011 service.

Schedule Page: 328.3 Line No.: 10 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 10 Column: c
Various signatories to the 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 11 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 11 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 11 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 12 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 12 Column: c
Various signatories to the 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.: 12 Column: m
December 2011 service.

Schedule Page: 328.3 Line No.: 13 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 13 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 13 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.
Schedule Page: 328.3 Line No.: 13 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.
Schedule Page: 328.3 Line No.: 14 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.: 14 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 14 Column: c
Various signatories to the 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.: 14 Column: m
December 2011 service.
Schedule Page: 328.3 Line No.: 15 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 15 Column: c
Various signatories to the 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
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.3 Line No.: 16 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 Line No.: 16 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.
Schedule Page: 328.3 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: 328.3 Line No.: 16 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.
Schedule Page: 328.3 Line No.: 17 Column: b
Sacramento Municipal Utility District.
Schedule Page: 328.3 Line No.: 17 Column: c
Sacramento Municipal Utility District.
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 on October 31, 2014.
Schedule Page: 328.3 Line No.: 17 Column: f
Malin 230 transformer.
Schedule Page: 328.3 Line No.: 17 Column: g
Malin 500 transformer.
Schedule Page: 328.3 Line No.: 17 Column: m

Extension of commencement date fee.

Schedule Page: 328.3 Line No.: 18 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 552) terminating on February 28, 2018.

Schedule Page: 328.3 Line No.: 18 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 19 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (8th Revised Service Agreement 552) terminating on February 28, 2018.

Schedule Page: 328.3 Line No.: 19 Column: m

Charges for spinning and/or supplemental reserves. Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2011 service.

Schedule Page: 328.3 Line No.: 20 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.: 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 between 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 April 2017.

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.

Schedule Page: 328.3 Line No.: 21 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 21 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 21 Column: d

Legacy contract (Rate Schedule 674) executed between 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 April 2017.

Schedule Page: 328.3 Line No.: 21 Column: m

Charge for transmission service over agreed-upon facilities and/or subject to a sole-use or facilities charge. December 2011 service.

Schedule Page: 328.3 Line No.: 22 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 22 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 23 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 23 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 24 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 24 Column: c

Various signatories to the 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. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 25 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 25 Column: c

Various signatories to the 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. December 2011 service.

Schedule Page: 328.3 Line No.: 26 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 26 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.3 Line No.: 27 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 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: 328.3 Line No.: 27 Column: m

Penalty revenues covering imbalance charges per Schedules 4 and 9. December 2011 service.

Schedule Page: 328.3 Line No.: 28 Column: b

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 28 Column: c

Operation, maintenance or facility lease services with no receipt or delivery of energy.

Schedule Page: 328.3 Line No.: 28 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 on February 12, 2020.

Schedule Page: 328.3 Line No.: 28 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.: 29 Column: a

This footnote applies to all occurrences of "Southern California Public Power" on pages 328 - 330. Complete name is Southern California Public Power Authority.

Schedule Page: 328.3 Line No.: 29 Column: d

Small Generator Interconnection Agreement (Service Agreement 629) executed between PacifiCorp and Southern California Public Power Authority terminating on November 30, 2019 or such other longer period as the Interconnection Customer may request and shall be automatically renewed for each successive one-year period thereafter, unless terminated earlier based on terms listed in the contract.

Schedule Page: 328.3 Line No.: 29 Column: m

Unauthorized use of transmission service. Penalty revenues covering imbalance charges per Schedules 4 and 9.

Schedule Page: 328.3 Line No.: 30 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.3 Line No.: 30 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 31 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (10th Revised Service Agreement 170) terminating on May 31, 2014.

Schedule Page: 328.3 Line No.: 31 Column: m

December 2011 service.

Schedule Page: 328.3 Line No.: 32 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 32 Column: c

Various signatories to the 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

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.3 Line No.: 33 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 33 Column: c

Various signatories to the 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.: 33 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service. Operating reserve - spinning reserve service. Operating reserve - supplemental reserve service.

Schedule Page: 328.3 Line No.: 34 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 34 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.3 Line No.: 34 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.3 Line No.: 34 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 1 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 1 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 1 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 2 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 2 Column: c
Various signatories to the 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.: 2 Column: m
December 2011 service.

Schedule Page: 328.4 Line No.: 3 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: 328.4 Line No.: 3 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 3 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 on October 1, 2014.

Schedule Page: 328.4 Line No.: 4 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 4 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 on October 1, 2014.

Schedule Page: 328.4 Line No.: 4 Column: m
Adjustment for 2011 transmission service.

Schedule Page: 328.4 Line No.: 5 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 5 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.: 5 Column: m
Penalty revenues covering imbalance charges per Schedules 4 and 9. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.4 Line No.: 6 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 6 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.: 6 Column: m
Penalty revenues covering imbalance charges per Schedules 4 and 9. Regulation and frequency response service. December 2011 service.

Schedule Page: 328.4 Line No.: 7 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 7 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 7 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 8 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 8 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 8 Column: d
Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 8 Column: m
December 2011 service.

Schedule Page: 328.4 Line No.: 9 Column: b
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 9 Column: c
Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 9 Column: m
Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 10 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.: 10 Column: m
Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.4 Line No.: 11 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.: 11 Column: m
Distribution voltage service charge. Primary delivery service. Regulation and frequency response service. December 2011 service.

Schedule Page: 328.4 Line No.: 12 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.: 13 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.: 13 Column: d
Legacy contract (2nd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, 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.: 13 Column: m

Energy consumption charge for deliveries at and below 138-kV.

Schedule Page: 328.4 Line No.: 14 Column: d

Legacy contract (2nd Revised Rate Schedule 286) executed between PacifiCorp and United States Department of the Interior, 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.: 14 Column: m

Energy consumption charge for deliveries at and below 138-kV. December 2011 service.

Schedule Page: 328.4 Line No.: 15 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.: 15 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (2nd Amended and Restated Transmission Service and Operating Agreement, 2nd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 15 Column: m

Scheduling and load following charges. Distribution voltage service charge. Charges for spinning and/or supplemental reserves. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.4 Line No.: 16 Column: d

Legacy contract executed between PacifiCorp and Utah Associated Municipal Power Systems for transmission service over agreed-upon facilities (2nd Amended and Restated Transmission Service and Operating Agreement, 2nd Revised Rate Schedule 297). Agreement subject to termination upon mutual agreement and replacement agreements are in effect.

Schedule Page: 328.4 Line No.: 16 Column: m

Charges for scheduling and load following. Distribution voltage service charge. December 2011 service.

Schedule Page: 328.4 Line No.: 17 Column: b

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 17 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 17 Column: d

Non-firm or short-term firm transmission service under the Open Access Transmission Tariff between various parties and points.

Schedule Page: 328.4 Line No.: 17 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service. Generation regulation and frequency response service.

Schedule Page: 328.4 Line No.: 18 Column: d

Legacy contract (4th 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.: 18 Column: m

Scheduling and load following charges. Charges for spinning and/or supplemental reserves. Scheduling, system control and dispatch service. Reactive supply and voltage control service. Regulation and frequency response service.

Schedule Page: 328.4 Line No.: 19 Column: d

Legacy contract (4th 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.: 19 Column: m

Scheduling and load following charges. December 2011 service.

Schedule Page: 328.4 Line No.: 20 Column: c

This footnote applies to all occurrences of "Portland General Electric" on pages 328 - 330. Complete name is Portland General Electric Company.

Schedule Page: 328.4 Line No.: 20 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 on January 31, 2032.

Schedule Page: 328.4 Line No.: 20 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: 328.4 Line No.: 21 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 on January 31, 2032.

Schedule Page: 328.4 Line No.: 21 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 2011 service.

Schedule Page: 328.4 Line No.: 22 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.4 Line No.: 22 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.: 22 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement.

Schedule Page: 328.4 Line No.: 23 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.4 Line No.: 23 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.: 23 Column: m

Fixed termination fee associated with a contract cancellation applied for the duration of this agreement. December 2011 service.

Schedule Page: 328.4 Line No.: 24 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.4 Line No.: 24 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 138-kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 24 Column: m

Charges for low-voltage transmission of power and energy.

Schedule Page: 328.4 Line No.: 25 Column: c

Various Western Area Power Administration customers in PacifiCorp's control area.

Schedule Page: 328.4 Line No.: 25 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 138-kV. Agreement termination upon three years after written notice and mutual consent.

Schedule Page: 328.4 Line No.: 25 Column: m

Charges for low-voltage transmission of power and energy. December 2011 service.

Schedule Page: 328.4 Line No.: 26 Column: a

This footnote applies to all occurrences of "Western Area Power Adm. CO MO" on pages 328 - 330. Complete name is Western Area Power Administration Colorado Missouri.

Schedule Page: 328.4 Line No.: 26 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 26 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 27 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 27 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 28 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 28 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.: 28 Column: m

December 2011 service.

Schedule Page: 328.4 Line No.: 29 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 Line No.: 29 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 page 332, Transmission of electricity by others, of this Form No 1.

Schedule Page: 328.4 Line No.: 30 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.4 Line No.: 30 Column: m

Distribution voltage service charge. Primary delivery service. Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 31 Column: d

Evergreen network transmission service under the Open Access Transmission Tariff (3rd Revised Service Agreement 175).

Schedule Page: 328.4 Line No.: 31 Column: m

Distribution voltage service charge. Primary delivery service. December 2011 service.

Schedule Page: 328.4 Line No.: 32 Column: a

This footnote applies to all occurrences of "Western Area Power Adm. CO River" on pages 328 - 330. Complete name is Western Area Power Administration Colorado River Storage Project.

Schedule Page: 328.4 Line No.: 32 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 32 Column: m

Scheduling, system control and dispatch service. Reactive supply and voltage control service.

Schedule Page: 328.4 Line No.: 33 Column: c

Various signatories to the Volume 11 Point-to-Point Transmission Tariff.

Schedule Page: 328.4 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: 328.4 Line No.: 33 Column: m

December 2011 service.

Schedule Page: 328.4 Line No.: 34 Column: d

Point-to-point transmission service under the Open Access Transmission Tariff (1st Revised Service Agreement 709) terminating on March 31, 2018.

Schedule Page: 328.4 Line No.: 34 Column: m

Extension of commencement date fee.

Schedule Page: 328.5 Line No.: 1 Column: m

Represents the difference between actual wheeling revenues for the period as reflected on the individual line items within this schedule, and the accruals credited to Account 456.1, Revenues from transmission of electricity for others, during the period and estimates for amounts subject to refund per FERC Docket No. ER11-3643 charged to Account 456.1, Revenues from transmission of electricity for others, during the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Arizona Public Service	LFP	301,061	301,061	1,140,058			1,140,058
2	Arizona Public Service	NF	75,567	75,567	362,454			362,454
3	Arizona Public Service	OS	15	15		2,890	5,711	8,601
4	Arizona Public Service	OS						
5	Arizona Public Service	SFP	8,877	8,877	57,043			57,043
6	Ashland, City of	AD	4,680	4,680		46,802		46,802
7	Ashland, City of	FNS	2,377	2,377		22,044		22,044
8	Avista Corporation	FNS	53,305	56,261	214,489			214,489
9	Avista Corporation	NF	54,690	54,690	287,853			287,853
10	Avista Corporation	SFP	4,800	4,800	18,460			18,460
11	Basin Elect. Power Coop	NF	97,169	97,169		144,782		144,782
12	Big Horn Rural Electric	OLF					199,860	199,860
13	Black Hills Power, Inc.	AD	11,760	11,760	79,056			79,056
14	Black Hills Power, Inc.	NF	416	416	885			885
15	Black Hills Power, Inc.	SFP	18,432	18,432	89,069			89,069
16	Bonneville Power Admin	AD	-21	-21	69,507	-20,982	-579,443	-530,918
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	FNS			6,140,993			6,140,993
2	Bonneville Power Admin	LFP	5,598,921	5,598,921	51,824,309			51,824,309
3	Bonneville Power Admin	NF	242,533	242,533		1,049,643		1,049,643
4	Bonneville Power Admin	OLF	2,639,814	2,836,843	30,866,085		98,317	30,964,402
5	Bonneville Power Admin	OS	27,680	27,680	11,900	83,427	4,716,140	4,811,467
6	Bonneville Power Admin	OS						
7	Bonneville Power Admin	SFP	418,209	418,209		2,161,891		2,161,891
8	CA Ind Sys Oper Corp	AD				11,845	-143,654	-131,809
9	CA Ind Sys Oper Corp	OS					746,138	746,138
10	CA Ind Sys Oper Corp	SFP	288,908	288,908		1,954,627		1,954,627
11	Deseret Gen & Trans	AD	955	955	-10,841			-10,841
12	Deseret Gen & Trans	LFP	241,736	241,736	4,554,688			4,554,688
13	Deseret Gen & Trans	NF	270,268	270,268	1,908,383			1,908,383
14	El Paso Electric Co.	NF	330	330	250			250
15	El Paso Electric Co.	OS					32	32
16	Flathead Elect Coop Inc	AD					7,511	7,511
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Flathead Elect Coop Inc	OS					81,375	81,375
2	Hermiston Gen Co L.P.	OS					184,498	184,498
3	Idaho Power Company	AD					7,419	7,419
4	Idaho Power Company	FNS			8,230			8,230
5	Idaho Power Company	LFP	2,253,091	2,455,284	6,132,562			6,132,562
6	Idaho Power Company	NF	34,392	34,392	178,461			178,461
7	Idaho Power Company	OS			-23,418		12,019,872	11,996,454
8	Idaho Power Company	OS						
9	Idaho Power Company	SFP	20,760	20,760	54,594			54,594
10	LA Dept of Water & Pwr	NF	10	10	90			90
11	LA Dept of Water & Pwr	OS					138	138
12	Moon Lake Elect. Assoc.	FNS					251,428	251,428
13	Morgan City Corporation	LFP	165	165		853		853
14	Morgan Stanley Capital	SFP			-293,838			-293,838
15	Nevada Power Company	NF	44,404	44,404	122,442			122,442
16	Nevada Power Company	OS					175,257	175,257
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

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	Nevada Power Company	SFP	374,062	374,062	843,368			843,368
2	NorthWestern Corp.	NF	106,441	106,441	461,704			461,704
3	NorthWestern Corp.	OS					22,315	22,315
4	NorthWestern Corp.	SFP	72	72	312			312
5	Platte River Pwr Auth	LFP	205,145	205,145	946,617			946,617
6	Platte River Pwr Auth	OS					8,508	8,508
7	Portland Gen. Electric	OLF					890	890
8	Powerex Corporation	SFP			-633,289			-633,289
9	Public Service Co of CO	LFP	67,818	71,101	942,896			942,896
10	Public Service Co of NM	LFP	109,494	109,494	690,347			690,347
11	Public Service Co of NM	NF	235	235	1,501			1,501
12	Public Service Co of NM	OS					19,387	19,387
13	Salt River Project	NF	20,500	20,500	41,439			41,439
14	Salt River Project	OS					958	958
15	Sierra Pacific Pwr Co	NF	93,082	93,082	598,728			598,728
16	Sierra Pacific Pwr Co	OS					207,514	207,514
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Sierra Pacific Pwr Co	SFP	159,691	159,691	878,308			878,308
2	Surprise Valley Electr.	OLF					10,836	10,836
3	Tri-State Gen & Transm	AD					-869	-869
4	Tri-State Gen & Transm	LFP	91,330	94,621	942,896			942,896
5	Tri-State Gen & Transm	NF	209,398	209,398	726,368			726,368
6	Tri-State Gen & Transm	OS					186,408	186,408
7	Tucson Electric Power	LFP	16,368	16,368	49,704			49,704
8	Tucson Electric Power	NF	3,000	3,000	13,516			13,516
9	Tucson Electric Power	OS					6,753	6,753
10	Tucson Electric Power	SFP	2,160	2,160	9,360			9,360
11	Westport Field Svc LLC	LFP			-3,489,354			-3,489,354
12	Western Area Power Admn	AD			-2,585		65,554	62,969
13	Western Area Power Admn	FNS			5,908,753			5,908,753
14	Western Area Power Admn	LFP	585,110	585,110	2,016,426			2,016,426
15	Western Area Power Admn	NF	336,679	336,679	814,572			814,572
16	Western Area Power Admn	OS					663,700	663,700
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	Western Area Power Admn	OS						
2	Western Area Power Admn	SFP	128,420	128,420	503,574			503,574
3	Accrual						582,359	582,359
4	Reserve						1,063,456	1,063,456
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		15,224,309	15,633,061	116,058,925	5,457,822	20,608,368	142,125,115

Schedule Page: 332 Line No.: 1 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.: 3 Column: g
Ancillary services.

Schedule Page: 332 Line No.: 4 Column: b
Arizona Public Service Company - Legacy contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Service Agreement between PacifiCorp and Arizona Public Service Company, Rate Schedule 436). The contract terminates October 31, 2020. See also page 328, Transmission of electricity for others, of this Form 1.

Schedule Page: 332 Line No.: 6 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 12 Column: b
Big Horn Rural Electric Company - contract termination date: March 10, 2015

Schedule Page: 332 Line No.: 12 Column: g
Use of facilities.

Schedule Page: 332 Line No.: 13 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 16 Column: b
Settlement adjustment.

Schedule Page: 332 Line No.: 16 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 2 Column: b
Bonneville Power Administration - contract termination dates: July 1, 2012; October 1, 2013; December 1, 2013; January 1, 2014; November 1, 2014; November 1, 2015; July 1, 2016; December 1, 2016; April 1, 2017; July 1, 2017; November 1, 2017; October 1, 2018; December 1, 2018; October 1, 2027; November 1, 2033; and evergreen

Schedule Page: 332.1 Line No.: 4 Column: b
Bonneville Power Administration - contract termination dates: October 3, 2014; December 31, 2018; September 30, 2027; and evergreen

Schedule Page: 332.1 Line No.: 4 Column: g
Use of facilities.

Schedule Page: 332.1 Line No.: 5 Column: g
Ancillary services. Use of facilities.

Schedule Page: 332.1 Line No.: 6 Column: b
Bonneville Power Administration - 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 page 328, Transmission of electricity for others, of this Form 1.

Schedule Page: 332.1 Line No.: 8 Column: a
This footnote applies to all occurrences of "CA Ind Sys Oper Corp" on page 332. Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 8 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 8 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 9 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 11 Column: b
Settlement adjustment.

Schedule Page: 332.1 Line No.: 12 Column: b

Deseret Generation and Transmission Cooperative - contract termination dates: October 31, 2012 and September 1, 2018

Schedule Page: 332.1 Line No.: 15 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 16 Column: b

Settlement adjustment.

Schedule Page: 332.1 Line No.: 16 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 1 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 2 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 332.2 Line No.: 3 Column: g

PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 5 Column: b

Idaho Power Company - contract termination dates: April 1, 2025 and July 1, 2025

Schedule Page: 332.2 Line No.: 7 Column: e

Credit for unreserved use.

Schedule Page: 332.2 Line No.: 7 Column: g

Ancillary services. Use of facilities. PacifiCorp's portion of specified costs of certain facilities.

Schedule Page: 332.2 Line No.: 8 Column: b

Idaho Power Company - 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 page 328, Transmission of electricity for others, of this Form 1.

Schedule Page: 332.2 Line No.: 10 Column: a

This footnote applies to all occurrences of "LA Dept of Water & Pwr" on page 332. Complete name is Los Angeles Department of Water and Power.

Schedule Page: 332.2 Line No.: 11 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 12 Column: g

Use of facilities.

Schedule Page: 332.2 Line No.: 13 Column: b

Morgan City Corporation - contract termination date: Evergreen

Schedule Page: 332.2 Line No.: 14 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.: 14 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.2 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 3 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 5 Column: b

Platte River Power Authority - contract termination date: October 31, 2017

Schedule Page: 332.3 Line No.: 6 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 7 Column: b

Portland General Electric Company - contract termination date: Upon two years written notice

Schedule Page: 332.3 Line No.: 7 Column: g

Use of facilities.

Schedule Page: 332.3 Line No.: 8 Column: e

Reassignment of Bonneville Power Administration transmission.

Schedule Page: 332.3 Line No.: 9 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.: 10 Column: b

Public Service Company of New Mexico - contract termination date: November 30, 2015

Schedule Page: 332.3 Line No.: 12 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 14 Column: g

Ancillary services.

Schedule Page: 332.3 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 2 Column: b

Surprise Valley Electrification Corp. - contract termination date: Evergreen

Schedule Page: 332.4 Line No.: 2 Column: g

Use of facilities.

Schedule Page: 332.4 Line No.: 3 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 3 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 4 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.: 6 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 7 Column: b

Tucson Electric Power Company - contract termination date: December 1, 2015

Schedule Page: 332.4 Line No.: 9 Column: g

Ancillary services.

Schedule Page: 332.4 Line No.: 11 Column: b

Westport Field Services, LLC - contract termination date: Evergreen

Schedule Page: 332.4 Line No.: 11 Column: e

Reimbursement for providing third party service.

Schedule Page: 332.4 Line No.: 12 Column: b

Settlement adjustment.

Schedule Page: 332.4 Line No.: 12 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.4 Line No.: 14 Column: b

Western Area Power Administration - contract termination date: May 31, 2022

Schedule Page: 332.4 Line No.: 16 Column: g

Ancillary services. Use of facilities.

Schedule Page: 332.5 Line No.: 1 Column: b

Western Area Power Administration - 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 page 328, Transmission of electricity for others, of this Form 1.

Schedule Page: 332.5 Line No.: 3 Column: g

Represents the difference between actual wheeling expenses for the period as reflected on the individual line items within this schedule, and the accruals charged to Account 565, Transmission of electricity by others, during the period.

Schedule Page: 332.5 Line No.: 4 Column: g

Reserve for potential liability associated with unreserved use penalty.

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

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,715,222
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	Albina Opportunities Corporation	5,000
10	Associated Oregon Industries	56,000
11	Clatsop Economic Development	5,000
12	Economic Development Corporation of Utah	9,100
13	Economic Development for Central Oregon	8,400
14	Electric Power Research Institute, Inc. - Prism 2.0	
15	Regional Energy and Economic Model Development Fees	350,000
16	Equal Employment Advisory Council	7,073
17	Four County Economic Development Corporation	37,500
18	Gorge Oregon Entrepreneurs Network	5,000
19	Idaho Economic Development Association	5,000
20	Intermountain Electrical Association	9,000
21	Northern Tier Transmission Group	446,097
22	Oregon Business Association	12,250
23	Oregon Business Council	25,808
24	Oregon Economic Development Association	15,000
25	Oregon Sports Authority Foundation	5,000
26	Oregon State University	15,000
27	Pacific Northwest Utilities Conference	70,981
28	Portland Business Alliance	52,500
29	Redmond Economic Development	7,000
30	Rock Springs Chamber of Commerce	5,750
31	Rocky Mountain Electrical League	15,500
32	Salt Lake Area Chamber of Commerce	30,542
33	Siskiyou County Economic Development	15,000
34	South Coast Development Council, Inc.	7,500
35	Southern Oregon Regional Economic Development Inc.	8,750
36	Utah Governor's Economic Summit	8,000
37	Utah Manufacturers Association	6,000
38	Utah Taxpayers Association	34,000
39	Utah Technology Council	5,500
40	WEST Associates	28,511
41	Western Electricity Coordinating Council	3,162,479
42	Western Energy Institute	36,260
43	Wyoming Business Alliance	6,000
44	Wyoming Taxpayers Association	20,455
45	Yakima County Development	7,500
46	TOTAL	7,338,998

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

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Other (individually < $5,000)	152,957
7		
8	Directors' Fees - Regional Advisory Boards	21,612
9		
10	Rating Agency and Trustee Fees:	
11	The Bank of New York Mellon	141,947
12	Computershare Shareowner Services, LLC	38,160
13	CUSIP Global Services	560
14	Financial Industry Regulatory Authority, Inc.	5,800
15	Fitch, Inc.	20,833
16	Moody's Investors Service, Inc.	222,017
17	NYSE Market, Inc.	82,500
18	Standard & Poor's Financial Services, LLC	320,000
19	U.S. Bank National Association	12,776
20		
21	General:	
22	Citizens Utility Board	5,000
23	Settlement Fees	6,425
24	Other	54
25		
26	Regulatory Asset Amortization:	
27	Goodnoe Hills Settlement - WY	21,250
28	Lake Side Settlement - WY	27,429
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45		
46	TOTAL	7,338,998

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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			41,692,182		41,692,182
2	Steam Production Plant	154,203,420				154,203,420
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	21,831,861		300,500		22,132,361
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	115,343,392				115,343,392
7	Transmission Plant	86,537,884				86,537,884
8	Distribution Plant	155,833,318				155,833,318
9	Regional Transmission and Market Operation					
10	General Plant	38,203,550		2,357,362		40,560,912
11	Common Plant-Electric					
12	TOTAL	571,953,425		44,350,044		616,303,469

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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Klamath River						
14	330.20 OR/CA	41			-1.90		7.00
15	330.40 OR/CA	1			-2.07		7.00
16	331.00 OR/CA	13,856			8.41		7.00
17	332.00 OR/CA	34,067			5.94		7.00
18	333.00 OR/CA	17,823			7.79		7.00
19	334.00 OR/CA	15,503			10.22		7.00
20	335.00 OR/CA	181			4.65		7.00
21	336.00 OR/CA	2,548			6.85		7.00
22							
23							
24							
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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, 2012, depreciation expense associated with transportation equipment was $15,898,715.

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.: 13 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 PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	4,535,884		4,535,884	
3	Rate Case		1,707,929	1,707,929	
4					
5	Oregon Public Utility Commission:				
6	Annual Fee	3,147,620		3,147,620	
7	Rate Case		1,554,980	1,554,980	
8	Deferred Intervenor Funding Grants				345,643
9					
10	Wyoming Public Service Commission:				
11	Annual Fee	1,415,560		1,415,560	
12	Rate Case		1,083,926	1,083,926	
13					
14	Washington Utilities and Transportation				
15	Commission:				
16	Annual Fee	574,750		574,750	
17	Rate Case		1,124,102	1,124,102	
18					
19	Idaho Public Utilities Commission:				
20	Annual Fee	506,579		506,579	
21	Rate Case		247,596	247,596	
22	Deferred Intervenor Funding Grants (2)		39,201	39,201	58,702
23					
24	California Public Utilities Commission:				
25	Annual Fee	948		948	
26	Rate Case		343,959	343,959	
27	Deferred Intervenor Funding Grants				32,885
28					
29	Rate Cases - All States		261,357	261,357	
30					
31	Federal Energy Regulatory Commission:				
32	Annual Fee	2,043,517		2,043,517	
33	Annual Fee - Hydro	2,983,740		2,983,740	
34	Transmission Rate Case		757,804	757,804	
35	Other Regulatory		365,986	365,986	
36					
37	Other Regulatory		259,773	259,773	
38					
39	Charges for services from MidAmerican Energy				
40	Holdings Company and its affiliates:				
41	Utah - Rate Case		1,816	1,816	
42	Wyoming - Rate Case		1,614	1,614	
43	Washington - Rate Case		1,227	1,227	
44	FERC - Transmission Rate Case		4,271	4,271	
45	FERC - Other Regulatory		1,833	1,833	
46	TOTAL	15,208,598	7,757,374	22,965,972	437,230

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	4,535,884					2
Electric	928	1,707,929					3
							4
							5
Electric	928	3,147,620					6
Electric	928	1,554,980					7
Electric	928		239,893			585,536	8
							9
							10
Electric	928	1,415,560					11
Electric	928	1,083,926					12
							13
							14
							15
Electric	928	574,750					16
Electric	928	1,124,102					17
							18
							19
Electric	928	506,579					20
Electric	928	247,596					21
Electric	928	39,201	49,705	928	39,201	69,206	22
							23
							24
Electric	928	948					25
Electric	928	343,959					26
Electric	928		67			32,952	27
							28
Electric	928	261,357					29
							30
							31
Electric	928	2,043,517					32
Electric	928	2,983,740					33
Electric	928	757,804					34
Electric	928	365,986					35
							36
Electric	928	259,773					37
							38
							39
							40
Electric	928	1,816					41
Electric	928	1,614					42
Electric	928	1,227					43
Electric	928	4,271					44
Electric	928	1,833					45
		22,965,972	289,665		39,201	687,694	46

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		- Toxic Release Inventory reporting for power plants program
4		- Prism 2.0 Regional Energy and Economic Model Development
5	(2) Research Support	Edison Electric Institute
6		- Utility Solid Waste Activities Group - membership dues
7		- Avian Power Line Interaction Committee - membership dues
8	(4) Research Support	National Electric Energy Testing, Research & Applications Center
9		- Membership dues
10		- Participation
11		
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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
	12,000	557	12,000		3
	350,000	930.2	350,000		4
					5
	77,589	930.2	77,589		6
	1,250	923	1,250		7
					8
	95,000	930.2	95,000		9
3,231		580	3,231		10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	93,582,637		
4	Transmission	10,163,006		
5	Regional Market			
6	Distribution	39,607,326		
7	Customer Accounts	40,371,041		
8	Customer Service and Informational	6,388,736		
9	Sales			
10	Administrative and General	41,294,116		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	231,406,862		
12	Maintenance			
13	Production	47,411,932		
14	Transmission	13,336,909		
15	Regional Market			
16	Distribution	69,305,897		
17	Administrative and General	1,803,880		
18	TOTAL Maintenance (Total of lines 13 thru 17)	131,858,618		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	140,994,569		
21	Transmission (Enter Total of lines 4 and 14)	23,499,915		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	108,913,223		
24	Customer Accounts (Transcribe from line 7)	40,371,041		
25	Customer Service and Informational (Transcribe from line 8)	6,388,736		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	43,097,996		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	363,265,480		363,265,480
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	363,265,480		363,265,480
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	144,657,545		144,657,545
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	144,657,545		144,657,545
72	Plant Removal (By Utility Departments)			
73	Electric Plant	9,090,299		9,090,299
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	9,090,299		9,090,299
77	Other Accounts (Specify, provide details in footnote):			
78	Fuel Stock	2,225,996		2,225,996
79	Miscellaneous Other Income Deductions	643,947		643,947
80	Charges to Affiliates	1,309,283		1,309,283
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	4,179,226		4,179,226
96	TOTAL SALARIES AND WAGES	521,192,550		521,192,550

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)	384,849	3,125,896	4,895,208	6,535,622
3	Net Sales (Account 447)	(4,168,463)	(5,738,731)	(8,675,216)	(12,268,026)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
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45					
46	TOTAL	(3,783,614)	(2,612,835)	(3,780,008)	(5,732,404)

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				152,206,512	MWh	11,109,603
2	Reactive Supply and Voltage	137,653,555	MWh	18,792,632	150,646,535	MWh	20,469,053
3	Regulation and Frequency Response	99,681,323	MWh	45,766,634	106,811,215	MWh	49,328,910
4	Energy Imbalance				-78,884	MWh	-1,633,644
5	Operating Reserve - Spinning	96,321,836	MWh	20,320,136	97,820,872	MWh	20,845,908
6	Operating Reserve - Supplement	96,321,836	MWh	17,283,747	97,820,872	MWh	17,731,244
7	Other				566	MWh	7,421
8	Total (Lines 1 thru 7)	429,978,550		102,163,149	605,227,688		117,858,495

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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	15,304	16	1800	8,445	115	4,936		222	1,586
2	February	14,917	6	800	8,118	102	4,936		226	1,535
3	March	14,617	7	800	7,799	103	4,930		272	1,513
4	Total for Quarter 1	44,838			24,362	320	14,802		720	4,634
5	April	14,430	23	1500	7,337	100	5,080		398	1,515
6	May	15,765	15	1600	8,006	103	5,080		1,046	1,530
7	June	17,078	29	1600	9,020	107	5,429		701	1,821
8	Total for Quarter 2	47,273			24,363	310	15,589		2,145	4,866
9	July	17,945	12	1500	9,831	124	5,429		658	1,903
10	August	17,437	6	1600	9,607	119	5,429		382	1,900
11	September	16,282	5	1700	8,667	104	5,429		302	1,780
12	Total for Quarter 3	51,664			28,105	347	16,287		1,342	5,583
13	October	14,847	2	1700	7,749	93	5,429		219	1,586
14	November	14,111	27	1800	8,212	104	4,317		92	1,561
15	December	15,442	18	1800	8,803	110	4,317		759	1,672
16	Total for Quarter 4	44,400			24,764	307	14,063		1,070	4,819
17	Total Year to Date/Year	188,175			101,594	1,284	60,741		5,277	19,902

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 2012 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 2012 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 2012 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 2012 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 2012 Net System Load information was estimated 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 2012 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 2012 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 2012 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 2012 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 2012 Net System Load information was estimated 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 2012 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 2012 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 2012 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 2012 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 2012 Net System Load information was estimated 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 2012 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. Peak load includes 207 megawatts of behind-the-meter generation including losses.

Schedule Page: 400 Line No.: 16 Column: f

4th Quarter 2012 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 2012 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 2012 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 2012 Net System Load information was estimated 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	54,549,341
3	Steam	44,760,136			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	223,987
5	Hydro-Conventional	4,268,481			
6	Hydro-Pumped Storage	-4,193	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	11,645,802
7	Other	8,244,632			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	57,269,056	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	152,155
10	Purchases	13,716,836	27	Total Energy Losses	4,593,819
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	71,165,104
12	Received	13,296,962			
13	Delivered	12,824,651			
14	Net Exchanges (Line 12 minus line 13)	472,311			
15	Transmission For Other (Wheeling)				
16	Received	13,731,215			
17	Delivered	13,615,562			
18	Net Transmission for Other (Line 16 minus line 17)	115,653			
19	Transmission By Others Losses	-408,752			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	71,165,104			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	6,458,846	1,200,879	8,445	16	1800 PST
30	February	5,872,954	1,059,757	8,118	6	0800 PST
31	March	5,797,684	1,013,117	7,799	7	0800 PST
32	April	5,218,740	849,119	7,337	23	1500 PDT
33	May	5,589,785	911,832	8,006	15	1600 PDT
34	June	5,782,404	759,959	9,020	29	1600 PDT
35	July	6,257,061	752,665	9,831	12	1500 PDT
36	August	6,250,962	696,862	9,607	6	1600 PDT
37	September	5,649,447	954,704	8,667	5	1700 PDT
38	October	5,728,568	1,022,840	7,520	2	1700 PDT
39	November	5,972,132	1,210,069	8,059	26	1800 PST
40	December	6,586,521	1,213,999	8,584	18	1800 PST
41	TOTAL	71,165,104	11,645,802			

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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)			175			401
7	Plant Hours Connected to Load			8784			8429
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			66			0
12	Net Generation, Exclusive of Plant Use - KWh			1287240000			2703937000
13	Cost of Plant: Land and Land Rights			956546			2625238
14	Structures and Improvements			15564033			61017735
15	Equipment Costs			103943645			464180495
16	Asset Retirement Costs			12106545			39000
17	Total Cost			132570769			527862468
18	Cost per KW of Installed Capacity (line 17/5) Including			702.9203			1275.0301
19	Production Expenses: Oper, Supv, & Engr			55626			1650019
20	Fuel			25897410			59141031
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			1649863			8412343
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			1936416			828656
26	Misc Steam (or Nuclear) Power Expenses			4187262			2003022
27	Rents			701			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			0			2331701
30	Maintenance of Structures			363620			629121
31	Maintenance of Boiler (or reactor) Plant			3581425			6049318
32	Maintenance of Electric Plant			576018			418957
33	Maintenance of Misc Steam (or Nuclear) Plant			291690			2615209
34	Total Production Expenses			38540031			84079377
35	Expenses per Net KWh			0.0299			0.0311
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	605690	1886	0	1553844	2889	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11976	138000	0	9214	130889	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.050	136.494	0.000	36.069	112.775	0.000
41	Average Cost of Fuel per Unit Burned	42.332	136.494	0.000	37.851	112.775	0.000
42	Average Cost of Fuel Burned per Million BTU	1.767	23.551	1.784	2.054	20.514	2.064
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.020	0.022	0.000	0.022
44	Average BTU per KWh Net Generation	11270.192	8.491	11278.683	10590.382	5.874	10596.256

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
		157			167			715	6
		8782			8784			8784	7
		0			0			0	8
		148			166			762	9
		0			0			0	10
		0			0			188	11
		1099064000			1344729000			4906422000	12
		1355853			137086			10449793	13
		59477328			36938999			153232758	14
		161050779			138302748			820487776	15
		39236			35149			11763714	16
		221923196			175413982			995934041	17
		1426.2416			1019.2561			1219.3120	18
		33138			334312			453938	19
		15728446			22290729			58092617	20
		0			0			0	21
		951802			1634156			309276	22
		0			0			0	23
		0			0			0	24
		69426			672401			0	25
		1250075			1064091			18653828	26
		16661			0			79282	27
		0			0			0	28
		226201			722759			0	29
		346458			401205			1885033	30
		2338341			3276490			12043020	31
		264357			774331			8101967	32
		296707			761195			1901122	33
		21521612			31931669			101520083	34
		0.0196			0.0237			0.0207	35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
702119	1005	0	680084	4	0	3383247	18331	0	38
8492	140000	0	9932	133693	0	8148	138000	0	39
19.957	131.343	0.000	31.508	126.088	0.000	16.622	139.683	0.000	40
22.213	131.343	0.000	32.729	126.088	0.000	16.414	139.683	0.000	41
1.308	22.337	1.318	1.648	22.484	1.650	1.007	24.100	1.052	42
0.014	0.000	0.014	0.017	0.000	0.017	0.011	0.001	0.012	43
10850.370	5.379	10855.749	10045.986	0.016	10046.002	11236.529	21.654	11258.183	44

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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)			78			425
7	Plant Hours Connected to Load			8663			8272
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			488619000			2904129000
13	Cost of Plant: Land and Land Rights			684632			9688975
14	Structures and Improvements			17623650			63278205
15	Equipment Costs			67147409			313642884
16	Asset Retirement Costs			532363			431476
17	Total Cost			85988054			387041540
18	Cost per KW of Installed Capacity (line 17/5) Including			1056.3643			845.6228
19	Production Expenses: Oper, Supv, & Engr			179935			0
20	Fuel			11686571			53314799
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			952473			3283594
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			329863			0
26	Misc Steam (or Nuclear) Power Expenses			430372			2495461
27	Rents			0			14243
28	Allowances			0			0
29	Maintenance Supervision and Engineering			315156			0
30	Maintenance of Structures			409933			2355738
31	Maintenance of Boiler (or reactor) Plant			1416973			6981365
32	Maintenance of Electric Plant			534236			1383908
33	Maintenance of Misc Steam (or Nuclear) Plant			457559			202364
34	Total Production Expenses			16713071			70031472
35	Expenses per Net KWh			0.0342			0.0241
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	234905	313	0	1323968	3226	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11411	137010	0	11226	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	49.795	137.545	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	49.426	137.545	0.000	39.926	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.166	23.902	2.179	1.778	24.309	1.792
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.024	0.018	0.000	0.018
44	Average BTU per KWh Net Generation	10972.076	3.682	10975.758	10235.932	6.439	10242.371

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

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Plant Name: *Hunter Unit No. 2* (d)			Plant Name: *Hunter Unit No. 3* (e)			Plant Name: *Hunter - Total Plant* (f)			Line No.
		Steam			Steam			Steam	1
		Outdoor Boiler			Outdoor Boiler			Outdoor Boiler	2
		1980			1983			1978	3
		1980			1983			1983	4
		294.50			495.60			1247.80	5
		276			484			1163	6
		8366			7479			8784	7
		0			0			0	8
		269			460			1147	9
		0			0			0	10
		0			0			216	11
		1820865000			2849599000			7574593000	12
		9688975			10275401			29653351	13
		52143586			91603209			207025000	14
		250825062			430662501			995130447	15
		431476			431476			1294428	16
		313089099			532972587			1233103226	17
		1063.1209			1075.4088			988.2219	18
		0			-55			-55	19
		31803729			52721821			137840349	20
		0			0			0	21
		2179725			3597337			9060656	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		1138435			2586494			6220390	26
		9166			15674			39083	27
		0			0			0	28
		0			0			0	29
		1553613			2971130			6880481	30
		6121020			15888629			28991014	31
		1488115			3558535			6430558	32
		88546			241566			532476	33
		44382349			81581131			195994952	34
		0.0244			0.0286			0.0259	35
Coal	Oil	Composite	Coal	Oil	Composite	Coal	Oil	Composite	36
Tons	Barrels		Tons	Barrels		Tons	Barrels		37
790593	1595	0	1274563	14908	0	3389124	19729	0	38
11469	138000	0	11354	138000	0	11331	138000	0	39
0.000	0.000	0.000	0.000	0.000	0.000	41.089	142.029	0.000	40
39.942	0.000	0.000	39.700	0.000	0.000	39.845	142.029	0.000	41
1.741	24.421	1.753	1.748	24.556	1.816	1.758	24.505	1.792	42
0.017	0.000	0.017	0.018	0.001	0.019	0.018	0.000	0.018	43
9959.099	5.077	9964.176	10156.768	30.322	10187.090	10139.602	15.096	10154.698	44

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

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Line No.	Item (a)	Plant Name: *Huntington* (b)			Plant Name: *Jim Bridger* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Outdoor Boiler			Semi-Outdoor
3	Year Originally Constructed			1974			1974
4	Year Last Unit was Installed			1977			1979
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			996.00			1545.10
6	Net Peak Demand on Plant - MW (60 minutes)			925			1421
7	Plant Hours Connected to Load			8784			8784
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			909			1407
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			161			341
12	Net Generation, Exclusive of Plant Use - KWh			6744160000			9250668000
13	Cost of Plant: Land and Land Rights			2386782			1161925
14	Structures and Improvements			118257607			140849737
15	Equipment Costs			702927608			921917205
16	Asset Retirement Costs			1207009			5049612
17	Total Cost			824779006			1068978479
18	Cost per KW of Installed Capacity (line 17/5) Including			828.0914			691.8507
19	Production Expenses: Oper, Supv, & Engr			14408			15997364
20	Fuel			95307621			203151812
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			8262629			3812213
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			307
26	Misc Steam (or Nuclear) Power Expenses			12905679			-12061776
27	Rents			1000			237500
28	Allowances			0			0
29	Maintenance Supervision and Engineering			1216824			482699
30	Maintenance of Structures			2152196			10093311
31	Maintenance of Boiler (or reactor) Plant			6825169			24620326
32	Maintenance of Electric Plant			1195547			8706752
33	Maintenance of Misc Steam (or Nuclear) Plant			1162346			2690211
34	Total Production Expenses			129043419			257730719
35	Expenses per Net KWh			0.0191			0.0279
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	2748248	5982	0	5078683	8259	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11774	138000	0	9331	138000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	34.998	139.360	0.000	35.566	134.041	0.000
41	Average Cost of Fuel per Unit Burned	34.376	139.360	0.000	39.783	134.041	0.000
42	Average Cost of Fuel Burned per Million BTU	1.460	24.044	1.472	2.132	23.126	2.142
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.014	0.022	0.000	0.022
44	Average BTU per KWh Net Generation	9595.574	5.141	9600.715	10245.890	5.175	10251.065

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
712	276	166	6
8784	8305	2240	7
0	0	0	8
687	268	231	9
0	0	0	10
139	67	35	11
5056959000	1990902000	120348000	12
1094739	210526	1252090	13
113655782	51193186	15104432	14
634446600	393394231	65835385	15
18809893	490453	587008	16
768007014	445288396	82778915	17
1085.9828	1537.0673	329.0100	18
153055	195245	50041	19
105801044	19828875	14231285	20
0	0	0	21
5562053	41419	0	22
0	0	0	23
0	0	0	24
59619	0	0	25
13061246	4422350	4053790	26
1259	15119	0	27
0	0	0	28
1083545	0	0	29
1320614	330423	152480	30
11294077	6347538	1014905	31
3763244	850363	2766347	32
910489	175264	316861	33
143010245	32206596	22585709	34
0.0283	0.0162	0.1877	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Gas	Composite	Coal	Oil	Composite	Gas			36
Tons	MCF		Tons	Barrels		MCF			37
2745732	89796	0	1503568	4499	0	1818972	0	0	38
9803	1041	0	7942	138000	0	1045	0	0	39
38.332	10.129	0.000	12.835	136.918	0.000	7.824	0.000	0.000	40
38.202	10.129	0.000	12.778	136.918	0.000	7.824	0.000	0.000	41
1.948	9.728	1.962	0.804	23.623	0.829	7.489	0.000	0.000	42
0.021	0.000	0.021	0.010	0.000	0.010	0.118	0.000	0.000	43
10645.435	18.490	10663.925	11996.030	13.098	12009.128	15790.026	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *Hermiston* (b)	Plant Name: *Blundell* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle	Steam - Geothermal
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Indoor
3	Year Originally Constructed	1996	1984
4	Year Last Unit was Installed	1996	2007
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	279.60	38.10
6	Net Peak Demand on Plant - MW (60 minutes)	245	36
7	Plant Hours Connected to Load	7424	8618
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	237	34
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	23
12	Net Generation, Exclusive of Plant Use - KWh	1149724000	268542000
13	Cost of Plant: Land and Land Rights	842245	41195596
14	Structures and Improvements	12844996	8234082
15	Equipment Costs	158510917	69321581
16	Asset Retirement Costs	214373	1744133
17	Total Cost	172412531	120495392
18	Cost per KW of Installed Capacity (line 17/5) Including	616.6400	3162.6087
19	Production Expenses: Oper, Supv, & Engr	0	25257
20	Fuel	47631026	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	1160323
23	Steam From Other Sources	0	3937027
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	9287696	0
26	Misc Steam (or Nuclear) Power Expenses	0	569202
27	Rents	0	5982
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	419519
31	Maintenance of Boiler (or reactor) Plant	0	193577
32	Maintenance of Electric Plant	0	629650
33	Maintenance of Misc Steam (or Nuclear) Plant	0	47214
34	Total Production Expenses	56918722	6987751
35	Expenses per Net KWh	0.0495	0.0260

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	8714895	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.465	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.465	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.360	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.041	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7728.566	0.000	0.000	0.000	0.000	0.000

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *Camas Co-Gen* (d)	Plant Name: *Chehalis* (e)	Plant Name: *Gadsby Peakers* (f)	Line No.
Steam	Combined Cycle	Gas Turbine	1
Outdoor Boiler	Outdoor	Outdoor	2
1996	2003	2002	3
1996	2003	2002	4
61.50	593.30	181.10	5
26	514	120	6
6568	2617	2445	7
0	0	0	8
14	520	120	9
0	0	0	10
0	18	0	11
78036000	849938000	94391000	12
0	1973791	0	13
5733734	23264896	4273000	14
28716806	314522888	76384121	15
0	689117	0	16
34450540	340450692	80657121	17
560.1714	573.8255	445.3734	18
0	176623	0	19
0	47149887	9415092	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
21507	2533731	596596	25
0	0	0	26
0	34668	0	27
0	0	0	28
0	0	0	29
0	110048	232891	30
0	0	0	31
0	2786575	638909	32
0	0	0	33
21507	52791532	10883488	34
0.0003	0.0621	0.1153	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
			Gas			Gas			36
			MCF			MCF			37
0	0	0	6431911	0	0	1210063	0	0	38
0	0	0	1033	0	0	1041	0	0	39
0.000	0.000	0.000	7.331	0.000	0.000	7.781	0.000	0.000	40
0.000	0.000	0.000	7.331	0.000	0.000	7.781	0.000	0.000	41
0.000	0.000	0.000	7.096	0.000	0.000	7.475	0.000	0.000	42
0.000	0.000	0.000	0.055	0.000	0.000	0.100	0.000	0.000	43
0.000	0.000	0.000	7817.313	0.000	0.000	13344.726	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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: *Currant Creek* (b)			Plant Name: *Lake Side* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2005			2007		
4	Year Last Unit was Installed	2006			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	566.90			591.30		
6	Net Peak Demand on Plant - MW (60 minutes)	567			552		
7	Plant Hours Connected to Load	7659			8500		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	550			558		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	19			25		
12	Net Generation, Exclusive of Plant Use - KWh	2132523000			2890938000		
13	Cost of Plant: Land and Land Rights	3403277			17278683		
14	Structures and Improvements	44108711			27840392		
15	Equipment Costs	325722454			311614489		
16	Asset Retirement Costs	134848			0		
17	Total Cost	373369290			356733564		
18	Cost per KW of Installed Capacity (line 17/5) Including	658.6158			603.3038		
19	Production Expenses: Oper, Supv, & Engr	67800			125481		
20	Fuel	111149193			149162596		
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	2769637			3741636		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	56			224		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	800026			1148289		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	6404209			803329		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	121190921			154981555		
35	Expenses per Net KWh	0.0568			0.0536		
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	15426336	0	0	20470520	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1055	0	0	1024	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	7.205	0.000	0.000	7.287	0.000	0.000
41	Average Cost of Fuel per Unit Burned	7.205	0.000	0.000	7.287	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	6.832	0.000	0.000	7.119	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.052	0.000	0.000	0.052	0.000	0.000
44	Average BTU per KWh Net Generation	7628.814	0.000	0.000	7247.963	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: *0* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
0			1
0			2
0			3
0			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	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	0	0	21
0	0	0	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

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	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

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

The Colstrip Plant is operated by PPL Montana, LLC and is jointly owned. PacifiCorp owns a 10.0% share of Colstrip Plant Unit Nos. 3 and 4. Data reported in column (d) represents PacifiCorp's share.

Schedule Page: 402 Line No.: -1 Column: e

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 Unit Nos. 1 and 2 and 12.86% of common facilities. Data in column (e) represents PacifiCorp's share.

Schedule Page: 402 Line No.: 11 Column: c

PacifiCorp does not have employees at the Cholla Plant.

Schedule Page: 402 Line No.: 11 Column: d

PacifiCorp does not have employees at the Colstrip Plant.

Schedule Page: 402 Line No.: 11 Column: e

PacifiCorp does not have employees at the Craig Plant.

Schedule Page: 402 Line No.: 20 Column: e

Amount includes intercompany profits.

Schedule Page: 402.1 Line No.: -1 Column: b

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, a 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 is operated by PacifiCorp and is jointly 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 2012 were $1.3 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 is operated by PacifiCorp and is jointly 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 2012 were $7.2 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.1 Line No.: -1 Column: f

Refer to plant statistics for each Hunter Unit Nos. 1, 2 and 3 on pages 402.1 and 403.1.

Schedule Page: 402.1 Line No.: 11 Column: b

PacifiCorp does not have employees at the Hayden Plant.

Schedule Page: 402.1 Line No.: 11 Column: c

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.1 Line No.: 11 Column: d

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.1 Line No.: 11 Column: e

Refer to Hunter - Total Plant on page 403.1 for the average number of employees.

Schedule Page: 402.2 Line No.: -1 Column: c

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

2012 were $26.2 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: -1 Column: e

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 2012 were $3.5 million and were primarily credited to Account 506, Miscellaneous steam power expenses.

Schedule Page: 402.2 Line No.: 20 Column: c

Amount includes intercompany profits.

Schedule Page: 402.3 Line No.: -1 Column: b

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 (b) 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: c

All or some of the renewable energy attributes associated with generation from the Blundell generating facility may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 402.3 Line No.: -1 Column: d

PacifiCorp owns the steam turbine generator and associated systems directly related to the operation of the Camas Co-Generation 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 Corporation retained ownership of these modifications. Georgia-Pacific Corporation 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 renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 402.3 Line No.: 11 Column: b

PacifiCorp does not have employees at the Hermiston Plant.

Schedule Page: 402.3 Line No.: 11 Column: d

PacifiCorp does not have employees at the Camas paper mill.

Schedule Page: 402.3 Line No.: 11 Column: f

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: 402.1 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	27	33
7	Plant Hours Connect to Load	8,715	8,727
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	28	34
10	(b) Under the Most Adverse Oper Conditions	28	34
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	85,352,000	109,416,000
13	Cost of Plant		
14	Land and Land Rights	107,019	20,914
15	Structures and Improvements	1,615,906	2,265,689
16	Reservoirs, Dams, and Waterways	2,851,569	2,954,724
17	Equipment Costs	5,261,118	10,342,093
18	Roads, Railroads, and Bridges	105,442	479,588
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	9,941,054	16,063,008
21	Cost per KW of Installed Capacity (line 20 / 5)	497.0527	594.9262
22	Production Expenses		
23	Operation Supervision and Engineering	-76,303	-101,905
24	Water for Power	0	0
25	Hydraulic Expenses	2,156	2,911
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,018,689	1,315,918
28	Rents	15,721	19,233
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	13,430	12,347
31	Maintenance of Reservoirs, Dams, and Waterways	18,156	-5,962
32	Maintenance of Electric Plant	65,490	44,013
33	Maintenance of Misc Hydraulic Plant	14,347	19,369
34	Total Production Expenses (total 23 thru 33)	1,071,686	1,305,924
35	Expenses per net KWh	0.0126	0.0119

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
10	22	29	6
8,739	8,069	5,687	7
			8
18	31	29	9
18	31	29	10
1	1	3	11
50,701,000	54,153,000	50,408,000	12
			13
0	0	3,511,185	14
1,226,050	1,737,299	3,968,892	15
4,526,756	14,745,199	7,582,608	16
1,193,576	1,771,075	14,601,489	17
50,817	250,151	572,059	18
0	0	0	19
6,997,199	18,503,724	30,236,233	20
466.4799	711.6817	1,007.8744	21
			22
-26,615	-29,194	-11,077	23
2,116	3,668	0	24
73,957	128,192	54,752	25
0	0	0	26
372,291	486,386	839,868	27
24,630	42,692	163	28
30	52	0	29
16,999	50,123	8,310	30
16,254	48,739	24,270	31
14,156	130,464	6,138	32
44,908	128,490	205,512	33
538,726	989,612	1,127,936	34
0.0106	0.0183	0.0224	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	30
7	Plant Hours Connect to Load	5,882	8,071
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	42,829,000	82,593,000
13	Cost of Plant		
14	Land and Land Rights	0	62,169
15	Structures and Improvements	918,915	1,962,958
16	Reservoirs, Dams, and Waterways	12,444,216	10,964,143
17	Equipment Costs	1,863,628	4,338,888
18	Roads, Railroads, and Bridges	533,015	105,373
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,759,774	17,433,531
21	Cost per KW of Installed Capacity (line 20 / 5)	1,432.7067	528.2888
22	Production Expenses		
23	Operation Supervision and Engineering	-14,124	-290,114
24	Water for Power	1,552	0
25	Hydraulic Expenses	54,235	68,200
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	353,115	1,651,269
28	Rents	18,062	9,350
29	Maintenance Supervision and Engineering	22	0
30	Maintenance of Structures	14,745	63,294
31	Maintenance of Reservoirs, Dams, and Waterways	27,143	214,758
32	Maintenance of Electric Plant	67,686	85,695
33	Maintenance of Misc Hydraulic Plant	32,932	99,606
34	Total Production Expenses (total 23 thru 33)	555,368	1,902,058
35	Expenses per net KWh	0.0130	0.0230

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	89	31	6
8,479	5,822	8,245	7
			8
19	83	32	9
19	83	32	10
1	1	1	11
100,757,000	240,436,000	166,546,000	12
			13
341,706	25,845	0	14
6,613,508	3,360,801	2,300,891	15
13,705,126	14,555,422	15,267,691	16
2,663,338	15,240,195	6,048,682	17
1,076,116	886,710	484,728	18
0	0	0	19
24,399,794	34,068,973	24,101,992	20
1,355.5441	347.7135	753.4227	21
			22
1,281,336	175,210	-34,808	23
0	0	4,513	24
4,310	10,564	157,726	25
0	0	0	26
925,564	752,476	615,183	27
12,945	2,980	52,527	28
0	0	64	29
6,536	40,707	53,693	30
17,231	26,908	137,241	31
163,127	53,572	96,296	32
12,912	126,698	95,774	33
2,423,961	1,189,115	1,178,209	34
0.0241	0.0049	0.0071	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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)	35	149
7	Plant Hours Connect to Load	8,774	8,782
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	207,037,000	657,225,000
13	Cost of Plant		
14	Land and Land Rights	0	1,086,417
15	Structures and Improvements	4,128,326	49,329,570
16	Reservoirs, Dams, and Waterways	31,090,995	11,855,653
17	Equipment Costs	11,737,456	18,375,213
18	Roads, Railroads, and Bridges	1,940,746	2,892,565
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	48,897,523	83,539,418
21	Cost per KW of Installed Capacity (line 20 / 5)	1,270.0655	614.2604
22	Production Expenses		
23	Operation Supervision and Engineering	-66,443	956,087
24	Water for Power	5,431	12,574
25	Hydraulic Expenses	189,823	697,204
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	692,173	749,343
28	Rents	63,216	57,016
29	Maintenance Supervision and Engineering	77	0
30	Maintenance of Structures	50,106	19,676
31	Maintenance of Reservoirs, Dams, and Waterways	51,703	135,168
32	Maintenance of Electric Plant	24,482	103,362
33	Maintenance of Misc Hydraulic Plant	115,264	373,448
34	Total Production Expenses (total 23 thru 33)	1,125,832	3,103,878
35	Expenses per net KWh	0.0054	0.0047

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
43	14	36	6
8,716	8,731	7,881	7
			8
45	28	36	9
45	28	36	10
1	2	1	11
263,788,000	32,971,000	238,047,000	12
			13
0	36,698	105,168	14
3,626,010	1,861,886	3,107,215	15
10,730,500	6,083,220	29,875,843	16
3,286,759	5,432,798	6,609,161	17
264,441	503,332	305,160	18
0	0	0	19
17,907,710	13,917,934	40,002,547	20
421.3579	463.9311	1,250.0796	21
			22
-37,979	-264,820	245,401	23
5,995	0	10,401	24
209,545	62,000	6,342	25
0	0	0	26
698,997	978,624	494,501	27
69,784	8,500	3,862	28
85	0	0	29
56,934	11,606	43,032	30
69,647	3,149	316,820	31
206,614	97,184	19,768	32
127,239	73,438	42,847	33
1,406,861	969,681	1,182,974	34
0.0053	0.0294	0.0050	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	9
7	Plant Hours Connect to Load	8,524	8,088
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	96,627,000	20,023,000
13	Cost of Plant		
14	Land and Land Rights	0	511,083
15	Structures and Improvements	2,173,443	713,731
16	Reservoirs, Dams, and Waterways	14,331,075	8,381,621
17	Equipment Costs	8,962,026	5,364,557
18	Roads, Railroads, and Bridges	463,083	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	25,929,627	14,970,992
21	Cost per KW of Installed Capacity (line 20 / 5)	1,440.5348	1,069.3566
22	Production Expenses		
23	Operation Supervision and Engineering	-28,680	-112,440
24	Water for Power	45,039	0
25	Hydraulic Expenses	88,749	28,934
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	409,034	552,784
28	Rents	29,556	3,967
29	Maintenance Supervision and Engineering	36	0
30	Maintenance of Structures	36,130	9,684
31	Maintenance of Reservoirs, Dams, and Waterways	22,467	32,817
32	Maintenance of Electric Plant	63,882	51,174
33	Maintenance of Misc Hydraulic Plant	53,890	33,791
34	Total Production Expenses (total 23 thru 33)	720,103	600,711
35	Expenses per net KWh	0.0075	0.0300

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
11	255	163	6
7,313	6,551	7,409	7
			8
12	264	164	9
12	263	164	10
2	2	2	11
50,541,000	809,468,000	702,744,000	12
			13
0	14,163,614	8,363,013	14
1,219,251	65,660,841	7,712,715	15
88,716,620	45,249,478	28,410,909	16
2,180,534	20,120,170	15,037,233	17
56,124	1,009,965	1,471,230	18
0	0	0	19
92,172,529	146,204,068	60,995,100	20
8,379.3208	609.1836	455.1873	21
			22
18,567	1,744,707	887,534	23
1,552	22,189	12,389	24
54,235	1,587,676	686,951	25
0	0	0	26
266,444	1,014,429	642,433	27
18,062	100,617	56,178	28
22	0	0	29
34,019	29,896	21,139	30
44,859	144,257	139,196	31
120,853	226,702	-42,059	32
32,932	614,959	354,647	33
591,545	5,485,432	2,758,408	34
0.0117	0.0068	0.0039	35

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 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)	7	0
7	Plant Hours Connect to Load	7,856	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	19,185,000	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	188,165	0
16	Reservoirs, Dams, and Waterways	0	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)	232,720	0
21	Cost per KW of Installed Capacity (line 20 / 5)	22.5942	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	-3,803	0
24	Water for Power	0	0
25	Hydraulic Expenses	18,798	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	357,499	0
28	Rents	56	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	-1,270	0
31	Maintenance of Reservoirs, Dams, and Waterways	9,879	0
32	Maintenance of Electric Plant	7,736	0
33	Maintenance of Misc Hydraulic Plant	171,161	0
34	Total Production Expenses (total 23 thru 33)	560,056	0
35	Expenses per net KWh	0.0292	0.0000

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

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

Copco No. 1
Pondage for peaking - storage, Upper Klamath Lake

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

Clearwater No. 1
Forebay for peaking

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

Clearwater No. 2
Forebay for peaking

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

Fish Creek
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.

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	3.9	1,903,000	35,512,686
3	Bend	1913	1.11	1.0	3,344,000	1,335,093
4	Big Fork 2652	1910	4.15	4.6	33,426,000	7,373,547
5	Eagle Point	1957	2.81	3.0	17,897,000	1,861,057
6	East Side 2082	1924	3.20	2.0		1,991,695
7	Fall Creek 2082	1903	2.20	2.0	10,432,000	1,395,011
8	Fountain Green	1922	0.16			597,630
9	Granite	1896	2.00	1.2	6,406,000	5,234,569
10	Gunlock	1917	0.75	0.5	1,489,000	683,045
11	Last Chance	1983	1.73	1.4	3,833,000	2,809,625
12	Paris	1910	0.72	0.7	2,434,000	432,494
13	Pioneer 2722	1897	5.00	4.0	15,091,000	11,000,932
14	Prospect No. 1 2630	1912	3.76	4.6	20,393,000	2,531,526
15	Prospect No. 3 2337	1932	7.20	8.0	37,518,000	8,343,868
16	Prospect No. 4 2630	1944	1.00	1.0	3,833,000	2,365,524
17	Sand Cove	1926	0.80	0.4	1,326,000	933,722
18	Stairs 597	1895	1.00	1.2	4,803,000	1,626,626
19	St. Anthony 2381	1915	0.50			1,337,279
20	Veyo	1920	0.50	0.3	1,030,000	893,125
21	Viva Naughton	1986	0.74	0.3	-45,000	1,194,486
22	Wallowa Falls 308	1921	1.10	1.0	5,611,000	2,887,127
23	Weber 1744	1911	3.85	2.0	15,100,000	2,962,109
24	West Side 2082	1908	0.60	0.6	1,810,000	468,574
25	Keno Regulating Dam 2082					7,527,975
26	Upper Klamath Lake 2082					3,847,587
27	North Umpqua 1927					15,458,169
28						
29	Pumping Plant:					
30	Lifton	1917	-4.50	-3.0	-4,193,000	19,248,145
31						
32	Wind:					
33	Dunlap Ranch 1	2010	111.00	112.0	387,973,000	239,618,218
34	Foote Creek	1999	32.15	33.0	85,137,000	36,515,908
35	Glenrock	2008	99.00	100.0	314,476,000	201,049,749
36	Glenrock III	2009	39.00	38.0	119,142,000	87,388,684
37	Rolling Hills	2009	99.00	100.0	292,022,000	201,829,100
38	Goodnoe Hills	2008	94.00	95.0	221,156,000	183,027,132
39	Leaning Juniper 1	2006	100.50	102.0	190,905,000	175,690,243
40	Marengo	2007	140.40	139.0	358,669,000	239,478,535
41	Marengo II	2008	70.20	69.0	177,552,000	129,148,793
42	Seven Mile Hill	2008	99.00	100.0	342,192,000	200,758,039
43	Seven Mile Hill II	2008	19.50	20.0	72,558,000	42,010,209
44	High Plains	2009	99.00	98.0	315,879,000	219,515,480
45	McFadden Ridge I	2009	28.50	29.0	94,789,000	56,961,391
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.
						1
5,300,401	367,409		76,526	Water		2
1,202,786	57,264		29,047	Water		3
1,776,758	313,976		50,310	Water		4
662,298	225,627		44,632	Water		5
622,405	37,406		6,920	Water		6
634,096	153,733		144,095	Water		7
3,735,188	5,679		1,088	Water		8
2,617,285	173,630		20,985	Water		9
910,727	65,737		58,452	Water		10
1,624,061	103,716		16,368	Water		11
600,686	63,914		47,888	Water		12
2,200,186	367,005		113,529	Water		13
673,278	169,165		23,354	Water		14
1,158,871	291,122		345,078	Water		15
2,365,524	50,335		25,067	Water		16
1,167,153	63,586		13,987	Water		17
1,626,626	133,818		13,834	Water		18
2,674,558	55,684		2,141	Water		19
1,786,250	67,832		91,170	Water		20
1,614,170	79,107		31,859	Water		21
2,624,661	77,992		68,798	Water		22
769,379	249,197		39,872	Water		23
780,957	56,414		14,359	Water		24
	8,093		23,399			25
	315,040		10,632			26
						27
						28
						29
-4,277,366	307,728		43,441	Water		30
						31
						32
2,158,723	489,426		2,017,563	Wind		33
1,135,798	1,660,970		2,500	Wind		34
2,030,806	400,851		2,057,419	Wind		35
2,240,735	46,584		601,039	Wind		36
2,038,678	421,491		1,097,841	Wind		37
1,947,097	656,635		1,407,823	Wind		38
1,748,162	1,568,930		1,134,225	Wind		39
1,705,688	1,598,918		2,137,651	Wind		40
1,839,726	716,078		1,058,379	Wind		41
2,027,859	591,417		1,849,355	Wind		42
2,154,370	99,170		360,024	Wind		43
2,217,328	868,449		2,565,222	Wind		44
1,998,645	238,105		746,044	Wind		45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Solar:					
2	Black Cap	2012	2.00	1.9	585,000	74,986
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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44						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
37,493	149,884			Solar		2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						19
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						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 renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 19 Column: a

St. Anthony

PacifiCorp has entered into an agreement for the sale of the St. Anthony hydroelectric generating facility with St. Anthony Hydro LLC, which is subject to certain regulatory approvals. For more information, refer to Important Changes During the Year, Item 3, in this FERC Form No. 1.

Schedule Page: 410 Line No.: 25 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.: 26 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.: 27 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.: 32 Column: a

Common 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 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 renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

Schedule Page: 410 Line No.: 34 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 34 represents PacifiCorp's share.

Schedule Page: 410.1 Line No.: 2 Column: a

PacifiCorp has entered into an agreement with RBS Asset Finance, Inc. to lease the Black Cap Solar generating facility. The lease has a 16-year term from October 2012 to October 2028 and is accounted for as an operating lease. For more information, refer to Important Changes During the Year, Item 4, in this FERC Form No. 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	MALIN , OR	PG&E ROUND MTN ,CA	500.00	500.00	Steel Tower	47.00		1
2	DIXONVILLE 500KV , OR	MERIDIAN , OR	500.00	500.00	Steel Tower	74.00		1
3	CAPTAIN JACK , OR	MALIN , OR	500.00	500.00	Steel Tower	7.00		1
4	KLAMATH CO-GEN , OR	CAPTAIN JACK , OR	500.00	500.00	Steel Tower	26.00		1
5	MERIDIAN , OR	KLAMATH CO-GEN , OR	500.00	500.00	Steel Tower	58.00		1
6	ALVEY , OR	DIXONVILLE 500KV , OR	500.00	500.00	Steel Tower	58.00		1
7	MIDPOINT , OR	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 500 kV					1,212.00		12
16								
17	90TH SOUTH , UT	CAMP WILLIAMS #4 , UT	345.00	345.00	Steel SP		11.00	1
18	90th SOUTH , UT	CAMP WILLIAMS #3 , UT	345.00	345.00		11.00		1
19	90TH SOUTH , UT	CAMP WILLIAMS #1 , UT	345.00	345.00	Steel SP		11.00	1
20	BEN LOMOND , UT	CAMP WILLIAMS , UT	345.00	345.00		69.00		1
21	BEN LOMOND , UT	TERMINAL , UT	345.00	345.00	Steel SP		47.00	1
22	BEN LOMOND , UT	TERMINAL , UT	345.00	345.00	Steel SP	47.00		1
23	BEN LOMOND , UT	POPULUS #1 , UT	345.00	345.00	Steel SP		82.00	1
24	BEN LOMOND , UT	POPULUS #2 , UT	345.00	345.00		86.00		1
25	CAMP WILLIAMS , UT	MONA , UT	345.00	345.00	Wood - H	47.00		1
26	CAMP WILLIAMS , UT	MONA #1 , UT	345.00	345.00	Wood - H	47.00		1
27	CAMP WILLIAMS , UT	MONA #2 , UT	345.00	345.00	Steel Tower	47.00		1
28	CAMP WILLIAMS , UT	MONA #4 , UT	345.00	345.00		5.00	42.00	1
29	CURRENT CREEK , UT	MONA , UT	345.00	345.00	Steel SP	1.00		1
30	EMERY , UT	HUNTINGTON , UT	345.00	345.00	Wood - H	20.00		1
31	EMERY , UT	SIGURD #1 , UT	345.00	345.00	Steel - H	74.00		1
32	EMERY , UT	SIGURD #2 , UT	345.00	345.00	Steel - H	75.00		1
33	EMERY , UT	CAMP WILLIAMS , UT	345.00	345.00	Steel Tower	121.00		1
34	FOUR CORNERS , NM	PINTO , UT	345.00	345.00	Wood - H	101.00		1
35	GOSHEN , ID	KINPORT , ID	345.00	345.00	Wood - H	41.00		1
36					TOTAL	16,076.00	741.00	272

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
	14,283,356	270,049,800	284,333,156		640,340	309,160	949,500	13
								14
	14,283,356	270,049,800	284,333,156		640,340	309,160	949,500	15
								16
								17
								18
1272 ACSR 45/7								19
1272 ACSR 45/7								20
1272 ACSR 45/7								21
1272 ACSR 45/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
954 ACSR 45/7								25
1272 ACSR 45/7								26
954 ACSR 45/7								27
954 ACSR 45/7								28
954 ACSR 54/7								29
954 ACSR 54/7								30
954 ACSR 45/7								31
954 ACSR 54/7								32
1272 ACSR 45/7								33
795 ACSR 45/7								34
795 ACSR 26/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	HUNTINGTON , UT	HUNT PLANT 1 , ID	345.00	345.00	Steel Tower	1.00		1
2	HUNTINGTON , UT	HUNT PLANT 2 , ID	345.00	345.00	Steel Tower	1.00		1
3	HUNTINGTON , UT	PINTO , ID	345.00	345.00	Steel SP	159.00		1
4	HUNTINGTON , UT	SPANISH FORK , ID	345.00	345.00	Steel Tower	78.00		1
5	JIM BRIDGER , WY	BORAH , ID	345.00	345.00	Steel Tower	240.00		1
6	JIM BRIDGER , WY	KINPORT , ID	345.00	345.00	Steel SP	234.00		1
7	MONA , UT	SIGURD #1 , UT	345.00	345.00	Wood - H	69.00		1
8	MONA , UT	SIGURD #2 , UT	345.00	345.00	Steel Tower		69.00	1
9	MONA , UT	HUNTINGTON , UT	345.00	345.00	Wood - H	60.00		1
10	SIGURD , UT	HARRY ALLEN, UT	345.00	345.00	Steel Tower	190.00		1
11	SPANISH FORK , WY	CAMP WILLIAMS , UT	345.00	345.00			35.00	1
12	TERMINAL , WY	BORAH , ID	345.00	345.00	Steel Tower	138.00		1
13	TERMINAL , WY	BORAH , ID	345.00	345.00			47.00	1
14	TERMINAL , WY	CAMP WILLIAMS #2 , UT	345.00	345.00	Steel SP	26.00		1
15	TERMINAL , WY	CAMP WILLIAMS , UT	345.00	345.00			23.00	1
16	TERMINAL , WY	90th SOUTH , UT	345.00	345.00			16.00	1
17	345 kV costs and expenses							
18								
19	Subtotal 345 kV					1,988.00	383.00	35
20								
21	ALVEY , OR	DIXONVILLE , OR	230.00	230.00	Wood - H	59.00		1
22	ANTELOPE , ID	ANACONDA, MT	230.00	230.00	Wood - H	76.00		1
23	ANTELOPE , ID	LOST RIVER , ID	230.00	230.00	Wood - H	20.00		1
24	ATLANTIC CITY , WY	COLUMBIA GENEVA , WY	230.00	230.00	Wood - H	1.00		1
25	BEN LOMOND , UT	NAUGHTON , WY	230.00	230.00	Wood - H	88.00		1
26	BEN LOMOND , UT	NAUGHTON , WY	230.00	230.00	Wood - H	88.00		1
27	BIRCH CREEK , UT	RAILROAD , WY	230.00	230.00	Wood - H	19.00		1
28	BITTER CREEK , WY	MONELL , WY	230.00	230.00	Wood - H	3.00		1
29	BRIDGER PUMP , WY	MANSFACE , WY	230.00	230.00	Wood - H	1.00		1
30	BUFFALO , WY	CASPER , WY	230.00	230.00	Wood - H	107.00		1
31	CASPER , WY	DAVE JOHNSTON , WY	230.00	230.00	Wood - H	36.00		1
32	CASPER , WY	RIVERTON , WY	230.00	230.00	Wood - H	110.00		1
33	CHAPPEL CREEK , WY	CRAVEN CREEK , WY	230.00	230.00	Steel SP	30.00		1
34	CHAPPEL CREEK , WY	RILEY RIDGE , WY	230.00	230.00	Wood - H	29.00	6.00	1
35	CHAPPEL CREEK , WY	JONAH GAS , WY	230.00	230.00	Wood - H	32.00		1
36					TOTAL	16,076.00	741.00	272

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.
2156 ACSR 8419								1
2156 ACSR 8419								2
795 ACSR 45/7								3
1272 ACSR 45/7								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
795 ACSR 45/7								7
954 ACSR 45/7								8
954 ACSR 54/7								9
954 ACSR 54/7								10
1272 ACSR 45/7								11
954 ACSR 45/7								12
1272 ACSR 45/7								13
1272 ACSR 45/7								14
1272 ACSR 45/7								15
1272 ACSR 45/7								16
	109,514,624	989,411,424	1,098,926,048	8,597	1,786,539	144,796	1,939,932	17
								18
	109,514,624	989,411,424	1,098,926,048	8,597	1,786,539	144,796	1,939,932	19
								20
1272 ACSR 36/1								21
795 ACSR 45/7								22
1272 ACSR 45/7								23
1272 ACSR 36/1								24
795 ACSR 26/7								25
795 ACSR 26/7								26
954 ACSR 54/7								27
795 ACSR 26/7								28
1272 ACSR 36/1								29
1272 ACSR 36/1								30
								31
1272 ACSR 36/1								32
954 ACSR 54/7								33
1272 ACSR 45/7								34
1272 ACSR 45/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	DAVE JOHNSTON , WY	SPENCE , WY	230.00	230.00	Wood - H	31.00		1
2	DAVE JOHNSTON , WY	WYODAK , WY	230.00	230.00	Wood - H	69.00		1
3	DIXONVILLE 500 KV , OR	DIXONVILLE , OR	230.00	230.00	Wood - H	1.00		1
4	DIXONVILLE , OR	RESTON BPA , OR	230.00	230.00	Wood - H	17.00		1
5	FAIRVIEW BPA , OR	ISTHMUS , OR	230.00	230.00	Wood - H	12.00		1
6	FIREHOLE , WY	MONUMENT , WY	230.00	230.00	Wood - H	49.00		1
7	FRY , OR	BETHEL , OR	230.00	230.00	Wood - H	26.00		1
8	FRY , OR	ALVEY , OR	230.00	230.00	Wood - H	45.00		1
9	GLEN CANYON , AZ	SIGURD , UT	230.00	230.00	Wood - H	159.00		1
10	GONDER (ELY) , AZ	PAVANT , UT	230.00	230.00	Wood - H	98.00		1
11	GOOSE CREEK , WY	BUFFALO , WY	230.00	230.00	Wood - H	43.00		1
12	GRANTS PASS , OR	DIXONVILLE , OR	230.00	230.00	Wood - H	62.00		1
13	HURRICANE , WA	WALLA WALLA , OR	230.00	230.00	Wood - H	78.00		1
14	JIM BRIDGER , WY	SPENCE , WY	230.00	230.00	Wood - H	149.00		1
15	JIM BRIDGER , WY	ROCK SPRINGS , WY	230.00	230.00	Wood - H	35.00		1
16	JONES CANYON (BPA) , OR	LEANING JUNIPER , OR	230.00	230.00	Wood - H	1.00		1
17	KLAMATH FALLS , OR	MALIN , OR	230.00	230.00	Wood - H	35.00		1
18	LIMA , WY	ROBERSON CREEK , WY	230.00	230.00	Wood - H	2.00		1
19	LONE PINE , OR	KLAMATH FALLS , OR	230.00	230.00	Wood - H	76.00		1
20	LONE PINE , OR	MERIDIAN , OR	230.00	230.00	Steel SP	5.00		1
21	MCNARY BPA , WA	WALLA WALLA , OR	230.00	230.00	Wood - H	56.00		1
22	MERIDIAN , OR	GRANTS PASS , OR	230.00	230.00	Wood - H	35.00		1
23	MERIDIAN , OR	LONE PINE , OR	230.00	230.00	Wood - H	5.00		1
24	MINERS , WY	HIGH PLAINS , WY	230.00	230.00	Wood - H	39.00		1
25	MONUMENT , WY	EXXON , WY	230.00	230.00	Wood - H	13.00		1
26	MONUMENT , WY	CRAVEN CREEK , WY	230.00	230.00	Wood - H	20.00		1
27	NAUGHTON , WY	TREASURETON , WY	230.00	230.00	Wood - H	80.00		1
28	NAUGHTON , WY	MONUMENT , WY	230.00	230.00	Wood - H	30.00		1
29	NAUGHTON , WY	WILLIAMS OPAL , WY	230.00	230.00	Wood - H	16.00		1
30	OREGON BASIN (PAC), WY	OR BASIN (MART OIL), WY	230.00	230.00	Wood - H	1.00		1
31	PALISADES SS , OR	BLUE RIM , WY	230.00	230.00	Wood - H	4.00		1
32	PAROWAN VALLEY , UT	SIGURD , UT	230.00	230.00	Wood - H	94.00		1
33	PAROWAN VALLEY , UT	WEST CEDAR , UT	230.00	230.00	Wood - H	26.00		1
34	PAVANT , UT	SIGURD , UT	230.00	230.00	Wood - H	43.00		1
35	POINT OF ROCKS , OR	DAVE JOHNSTON , WY	230.00	230.00	Wood - H	209.00		1
36					TOTAL	16,076.00	741.00	272

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
1272 ACSR 36/1								2
1272 ACSR 36/1								3
795 ACSR 26/7								4
1272 ACSR 36/1								5
1272 ACSR 45/7								6
1272 ACSR 36/1								7
1272 ACSR 36/1								8
954 ACSR 45/7								9
795 ACSR 45/7								10
795 ACSR 26/7								11
1272 ACSR 36/1								12
1272 ACSR 36/1								13
1272 ACSR 36/1								14
1272 ACSR 36/1								15
1272 ACSR 45/7								16
1272 ACSR 36/1								17
1272 ACSR 45/1								18
795 ACSR 26/7								19
1272 ACSR 36/1								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
1272 ACSR 54/19								23
1272 ACSR 45/7								24
1272 ACSR 36/1								25
1272 ACSR 45/7								26
1272 ACSR 45/7								27
1272 ACSR 36/1								28
954 ACSR 54/7								29
1272 ACSR 45/7								30
1272 ACSR 36/1								31
795 ACSR 45/7								32
795 ACSR 45/7								33
795 ACSR 45/7								34
1272 ACSR 36/1								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	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.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	POMONA , WA	UNION GAP , WA	230.00	230.00	Wood - H	8.00		1
2	RIVERTON , WY	ROCK SPRINGS , WY	230.00	230.00	Wood - H	118.00		1
3	RIVERTON , WY	THERMOPOLIS , WY	230.00	230.00	Wood - H	51.00		1
4	ROCK CREEK (BPA) , WA	GOODNOE HILLS , WA	230.00	230.00	Wood - H	1.00		1
5	ROCK SPRINGS , WY	FLAMING GORGE , UT	230.00	230.00	Wood - H	55.00		1
6	ROCK SPRINGS , WY	JIM BRIDGER , WY	230.00	230.00	Wood - H	35.00		1
7	ROCK SPRINGS , WY	MONUMENT , WY	230.00	230.00	Wood - H	41.00		1
8	SHIRLEY BASIN , OR	DUNLAP , WY	230.00	230.00	Wood - H	12.00		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	TALBOT , WA	MARENGO II , WA	230.00	230.00	Wood - H	7.00		1
12	TAP TO DALREED , OR	TAP TO DALREED No.2, OR	230.00	230.00	Wood - H	1.00		1
13	TAP TO HANNA , OR	NICKEL MOUNTAIN , OR	230.00	230.00	Wood - H	9.00		1
14	THERMOPOLIS , WY	YELLOWTAIL , MT	230.00	230.00	Wood - H	176.00		1
15	TREASURETON , ID	BRADY , ID	230.00	230.00	Wood - H	66.00		1
16	TROUTDALE BPA , OR	GRESHAM PGE , OR	230.00	230.00	Steel Tower	6.00		1
17	TROUTDALE BPA , OR	LINNEMAN PGE , OR	230.00	230.00			6.00	1
18	TROUTDLE-LINNEMN, OR	TROUTDALE PP&L , OR	230.00	230.00	Wood - H	1.00		1
19	UNION GAP , OR	MIDWAY (BPA) , OR	230.00	230.00	Wood - H	39.00		1
20	WALLA WALLA , OR	AVISTA LEWISTON , WA	230.00	230.00	Wood - H	45.00		1
21	WALLA WALLA , OR	WANAPUM (GPUD) , WA	230.00	230.00	Wood - H	33.00		1
22	WANAPUM , OR	POMONA , WA	230.00	230.00	Wood - H	37.00		1
23	WINDSTAR , OR	GLENROCK/ROLLING, WA	230.00	230.00	Wood - H	13.00		1
24	WYODAK , WY	BUFFALO , WY	230.00	230.00	Wood - H	69.00		1
25	YAMSAY , OR	KLAMATH FALLS , OR	230.00	230.00	Wood - H	63.00		1
26	YELLOWTAIL , OR	GOOSE CREEK , WY	230.00	230.00	Wood - H	59.00		1
27	230 kV costs and expenses							
28								
29	Subtotal 230 kV					3,333.00	12.00	76
30								
31	ANACONDA, ID	JEFFERSON, ID	161.00	161.00	Wood - H		61.00	1
32	ANTELOPE , ID	GOSHEN , ID	161.00	161.00	Wood - H	45.00		1
33	BONNEVILLE , ID	EAGLEROCK , ID	161.00	161.00	Wood SP	9.00		1
34	EAGLEROCK , ID	SUGARMILL , ID	161.00	161.00	Wood SP	3.00		1
35	EAGLEROCK , ID	GOSHEN , ID	161.00	161.00	Wood - H	12.00		1
36					TOTAL	16,076.00	741.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
1272 ACSR 36/1								2
1272 ACSR 36/1								3
1272 ACSR 45/7								4
1272 ACSR 36/1								5
1272 ACSR 36/1								6
1272 ACSR 36/1								7
795 ACSR 26/7								8
954 ACSR 45/7								9
954 ACSR 45/7								10
795 ACSR 26/7								11
795 ACSR 26/7								12
795 ACSR 26/7								13
1272 ACSR 36/1								14
795 ACSR 26/7								15
954 ACSR 45/7								16
900 ACSR 54/7								17
1272 ACSR 36/1								18
954 ACSR 45/7								19
1272 ACSR 36/1								20
1272 ACSR 36/1								21
1272 ACSR 36/1								22
1272 ACSR 45/7								23
1272 ACSR 36/1								24
795 ACSR 26/7								25
795 ACSR 26/7								26
	16,519,791	357,004,905	373,524,696	50,077	4,818,539	351,027	5,219,643	27
								28
	16,519,791	357,004,905	373,524,696	50,077	4,818,539	351,027	5,219,643	29
								30
250HH CU/7								31
397.5 ACSR 26/7								32
954 ACSR 45/7								33
954 ACSR 45/7								34
1272 ACSR 45/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

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

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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION 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	GOSHEN , ID	GRACE , ID	161.00	161.00	Wood - H	57.00		1
2	GOSHEN , ID	JEFFERSON , ID	161.00	161.00	Wood - H		29.00	1
3	GOSHEN , ID	RIGBY , ID	161.00	161.00	Wood - H	31.00		1
4	GOSHEN , ID	SUGAR MILL , ID	161.00	161.00	Wood SP	17.00		1
5	RIGBY , ID	JEFFERSON , ID	161.00	161.00	Wood SP	18.00		1
6	SUGARMILL , ID	RIGBY , ID	161.00	161.00	Wood SP	17.00		1
7	YELLOWTAIL , MT	RIMROCK , ID	161.00	161.00	Wood - H	46.00		1
8	161 kV costs and expenses							
9								
10	Subtotal 161 kV					255.00	90.00	12
11								
12	90TH SOUTH , UT	SANDY , UT	138.00	138.00	Steel - SP	1.00		1
13	90TH SOUTH , UT	QUARRY , UT	138.00	138.00	Wood - H	12.00		1
14	90TH SOUTH , UT	DUMAS , UT	138.00	138.00	Wood - H	6.00		1
15	90TH SOUTH , UT	OQUIRRH , UT	138.00	138.00	Wood SP	10.00		1
16	ABAJO , UT	PINTO , UT	138.00	138.00	Wood - H	44.00		1
17	AGRIUM , UT	THREEMILE KNOLL , ID	138.00	138.00	Wood - H	4.00		1
18	ANSCHTZ CO-GEN, WY	EVANSTON , WY	138.00	138.00	Wood - H	22.00		1
19	ANTELOPE , ID	SCOVILLE #1 , WY	138.00	138.00	Wood - H	1.00		1
20	ANTELOPE , ID	SCOVILLE #2 , WY	138.00	138.00	Wood - H	1.00		1
21	ASHGROVE , ID	CLOVER , WY	138.00	138.00	Wood - H	26.00		1
22	ASHLEY , UT	CARBON , UT	138.00	138.00	Wood - H	92.00		1
23	ASHLEY , UT	VERNAL , UT	138.00	138.00	Wood - H	12.00		1
24	BANGERTER , UT	OQUIRRH , UT	138.00	138.00	Wood - H		6.00	1
25	BEN LOMOND , UT	BRIGHAM CITY , UT	138.00	138.00	Wood - H	14.00		1
26	BEN LOMOND #1 , UT	EL MONTE , UT	138.00	138.00	Steel - SP	14.00		1
27	BEN LOMOND #2 , UT	EL MONTE , UT	138.00	138.00			13.00	1
28	BEN LOMOND , UT	HONEYVILLE , UT	138.00	138.00			22.00	1
29	BEN LOMOND , UT	SYRACUSE , UT	138.00	138.00	Steel Tower	7.00	13.00	1
30	BEN LOMOND , UT	ANGEL #2 , UT	138.00	138.00	Steel - SP	28.00		1
31	BEN LOMOND , UT	W ZIRCONIUM , UT	138.00	138.00	Wood -SP	14.00		1
32	BEN LOMOND , UT	WHEELON , UT	138.00	138.00	Steel Tower	42.00		1
33	BEN LOMOND , UT	SYRACUSE , UT	138.00	230.00	Steel Tower	25.00		1
34	BONANZA , UT	CHAPITA , UT	138.00	138.00	Wood - H	9.00		1
35	BRIDGERLAND , UT	GREEN CANYON , UT	138.00	138.00	Wood -SP	16.00		1
36					TOTAL	16,076.00	741.00	272

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

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
250HH CU/7								1
250HH CU/7								2
397.5 ACSR 26/7								3
795 AAC /37								4
397.5 ACSR 26/7								5
397.5 ACSR 26/7								6
556.5 ACSR 26/7								7
	623,490	20,881,126	21,504,616		249,715	14,301	264,016	8
								9
	623,490	20,881,126	21,504,616		249,715	14,301	264,016	10
								11
795 AAC /37								12
795 AAC /37								13
795 AAC /37								14
795 ACSR 26/7								15
397.5 ACSR 26/7								16
397.5 ACSR 26/7								17
795 ACSR 26/7								18
397.5 ACSR 26/7								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
397.5 ACSR 26/7								22
397.5 ACSR 26/7								23
								24
1272 ACSR 45/7								25
795 ACSR 45/7								26
795 ACSR 45/7								27
250 CUHD /12								28
795 AAC /37								29
397.5 ACSR 26/7								30
795 AAC /37								31
250 CUHD /12								32
1272 ACSR 45/7								33
795 ACSR 26/7								34
1272 ACSR 45/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	BRIGHAM CITY , UT	WHEELON , UT	138.00	138.00	Wood - H	24.00		1
2	BUTLERVILLE , UT	90TH SOUTH , UT	138.00	138.00	Steel - SP	9.00		1
3	CAMERON , UT	PAROWAN , UT	138.00	138.00	Wood - H	35.00		1
4	CAMERON , UT	SIGURD , UT	138.00	138.00	Wood - H	64.00		1
5	CANYON COMP, WY	STR 204 , UT	138.00	138.00	Wood - H	12.00		1
6	CARBON , UT	HELPER #2 , UT	138.00	138.00	Wood - H	2.00		1
7	CARBON #1 , UT	SPANISH FORK , UT	138.00	138.00	Steel Tower	54.00		1
8	CARBON #2 , UT	SPANISH FORK , UT	138.00	138.00		52.00		1
9	CARBON , UT	MOAB , UT	138.00	138.00	Wood - H	120.00		1
10	CLEAR CREEK , WY	PAINTER , UT	138.00	138.00	Wood -SP	5.00		1
11	CLOVER , WY	NEBO , UT	138.00	138.00	Wood -SP	8.00		1
12	COLUMBIA , UT	SUNNYSIDE , UT	138.00	138.00	Wood - H	2.00		1
13	COTTONWOOD , UT	MCCLELLAND , UT	138.00	138.00	Steel - SP	6.00		1
14	COTTONWOOD , UT	HAMMER , UT	138.00	138.00	Wood -SP	5.00		1
15	COTTONWOOD , UT	SILVER CREEK , UT	138.00	138.00	Wood -SP	29.00		1
16	CUTLER , UT	WHEELON , UT	138.00	138.00	Wood -SP	1.00		1
17	DRY CREEK , UT	SPANISH FORK , UT	138.00	138.00	Steel - SP	5.00		1
18	DUMAS , UT	WESTFIELD , UT	138.00	138.00	Wood -SP	18.00		1
19	DYNAMO , UT	TRI-CITY #1 , UT	138.00	138.00	Steel - SP	2.00		1
20	DYNAMO , UT	TRI-CITY #2 , UT	138.00	138.00			3.00	1
21	EAST LAYTON , UT	105 TAP , UT	138.00	138.00	Steel - SP		15.00	1
22	EBAY TAP , UT	OQUIRRH , UT	138.00	138.00	Wood -SP	1.00		1
23	EL MONTE , UT	STR 30B , UT	138.00	138.00	Steel - SP	4.00		1
24	EL MONTE , UT	PIONEER , UT	138.00	138.00	Steel - SP	1.00		1
25	EVANSTON , WY	RAILROAD , UT	138.00	138.00	Wood -SP	3.00		1
26	FRANKLIN , ID	TREASURETON , ID	138.00	138.00	Wood -SP	10.00		1
27	FRANKLIN , ID	GREEN CANYON , UT	138.00	138.00	Wood -SP	25.00		1
28	GADSBY , UT	JORDAN , UT	138.00	138.00	Wood -SP	1.00		1
29	GADSBY , UT	THIRD WEST , UT	138.00	138.00	Wood -SP	1.00		1
30	GADSBY , UT	TERMINAL , UT	138.00	138.00	Wood -SP	6.00		1
31	GENEVA , UT	TIMP , UT	138.00	138.00	Wood -SP	1.00		1
32	GREEN CANYON , UT	NIBLEY , UT	138.00	138.00	Wood -SP	7.00		1
33	GREEN CANYON , UT	WHEELON , UT	138.00	138.00	Wood -SP	19.00		1
34	HALE , UT	MIDWAY , UT	138.00	138.00	Wood - H	19.00		1
35	HALE , UT	TANNER , UT	138.00	138.00	Wood - H	7.00		1
36					TOTAL	16,076.00	741.00	272

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 AAC /37								2
397.5 ACSR 26/7								3
397.5 ACSR 26/7								4
795 ACSR 26/7								5
556.5 ACSR 26/7								6
795 ACSR 26/7								7
1272 ACSR 45/7								8
954 ACSR 54/7								9
795 ACSR 26/7								10
1272 ACSR 45/7								11
397.5 ACSR 26/7								12
795 AAC /37								13
795 AAC /37								14
397.5 ACSR 26/7								15
250 CUHD /12								16
1272 ACSR 45/7								17
795 ACSR 26/7								18
795 ACSR 26/7								19
795 ACSR 26/7								20
795 ACSR 26/7								21
795 ACSR 26/7								22
1272 ACSR 45/7								23
1272 ACSR 45/7								24
795 ACSR 26/7								25
795 ACSR 26/7								26
397.5 ACSR 26/7								27
1272 ACSR 45/7								28
1272 AAC /61								29
1272 ACSR 45/7								30
1272 AAC /61								31
1272 ACSR 45/7								32
397.5 ACSR 26/7								33
397.5 ACSR 26/7								34
1272 ACSR 45/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

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

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	HALE , UT	SPANISH FORK , UT	138.00	138.00	Wood - H	18.00		1
2	HAMMER , UT	BUTLERVILLE , UT	138.00	138.00			2.00	1
3	HONEYVILLE , UT	LAMPO , UT	138.00	138.00	Wood - H	25.00		1
4	HONEYVILLE , UT	WHEELON , UT	138.00	138.00			14.00	1
5	HUNTINGTON , UT	MCFADDEN , UT	138.00	138.00	Wood - H	7.00		1
6	JERUSALEM , UT	NEBO , UT	138.00	138.00	Wood - H	26.00		1
7	JORDAN , UT	THIRD WEST , UT	138.00	138.00	Wood -SP	1.00		1
8	JORDAN , UT	MCCLELLAND , UT	138.00	138.00	Wood -SP	5.00		1
9	JORDAN , UT	TERMINAL , UT	138.00	138.00	Wood -SP	6.00		1
10	KCC BARNEY , UT	KCCGRIND , UT	138.00	138.00	Wood -SP	1.00		1
11	KEARNS , UT	TAYLORSVILLE , UT	138.00	138.00	Wood -SP	3.00		1
12	KEARNS , UT	WEST VALLEY , UT	138.00	138.00	Wood -SP	2.00		1
13	LONE PEAK , UT	CAMP WILLIAMS , UT	138.00	138.00			8.00	1
14	MCCLELLAND , UT	MIDVALLEY , UT	138.00	138.00	Wood -SP	6.00		1
15	MCFADDEN , UT	BLACKHAWK , UT	138.00	138.00	Wood - H	11.00		1
16	MID VALLEY , UT	TAYLORSVILLE , UT	138.00	138.00	Wood -SP	4.00	2.00	1
17	MID VALLEY , UT	COTTONWOOD , UT	138.00	138.00	Wood -SP	5.00		1
18	MID VALLEY , UT	COTTONWOOD , UT	138.00	138.00	Wood -SP	3.00		1
19	MID VALLEY , UT	90TH SOUTH , UT	138.00	138.00	Wood - H	9.00		1
20	MIDDLETON , UT	ST. GEORGE , UT	138.00	138.00	Wood - H	1.00		1
21	MOAB , UT	PINTO , UT	138.00	138.00	Wood - H	68.00		1
22	NAUGHTON , WY	CANYON COMP, WY	138.00	138.00	Wood - H	36.00		1
23	NAUGHTON , WY	PAINTER , WY	138.00	138.00	Wood - H	48.00		1
24	NEBO , UT	DRY CREEK , UT	138.00	138.00	Wood - H	33.00		1
25	NUCOR STEEL , UT	WHEELON , UT	138.00	138.00	Wood - H	10.00		1
26	ONEIDA , ID	OVID , UT	138.00	138.00	Wood - H	23.00		1
27	ONIEDA , ID	GRACE , ID	138.00	138.00	Wood - H	19.00		1
28	OQUIRRH , UT	TOOELE , ID	138.00	138.00	Wood -SP	21.00		1
29	OQUIRRH , UT	BARNEY , UT	138.00	138.00	Wood - H	5.00		1
30	OQUIRRH , UT	KCC BINGHAM , UT	138.00	138.00	Wood - H	8.00		1
31	PAINTER , UT	RAILROAD , UT	138.00	138.00	Wood - H	7.00		1
32	PAROWAN , UT	WEST CEDAR , UT	138.00	138.00	Wood - H	21.00		1
33	PARRISH #1 , UT	TERMINAL , UT	138.00	138.00	Steel - SP	16.00		1
34	PARRISH #105 , UT	TERMINAL , UT	138.00	138.00	Steel - SP	14.00		1
35	PARISH #2 , UT	TERMINAL , UT	138.00	138.00			14.00	1
36					TOTAL	16,076.00	741.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
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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 45/7								1
795 ACSR 26/7								2
397.5 ACSR 26/7								3
250 CUHD /12								4
397.5 ACSR 26/7								5
397.5 ACSR 26/7								6
1272 AAC /61								7
795 AAC /37								8
1272 AAC/91								9
1272 AAC /61								10
500 AAC/19								11
								12
1272 ACSR 45/7								13
795 AAC 26/7								14
795 AAC 26/7								15
1272 ACSR /61								16
								17
								18
1272 ACSR 45/7								19
397.5 ACSR 26/7								20
397.5 ACSR 26/7								21
795 AAC 26/7								22
795 AAC 26/7								23
795 AAC 26/7								24
397.5 ACSR 26/7								25
336.4 ACSR 26/7								26
250 CUHD /12								27
795 AAC 45/7								28
795 AAC 26/7								29
1557.4 ACSR/TW								30
1272 ACSR 45/7								31
397.5 ACSR 26/7								32
795 AAC 45/7								33
795 AAC 45/7								34
795 AAC 26/7								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

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

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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	PARRISH , UT	TAP TO N SALT LAKE , UT	138.00	138.00	Steel - SP		8.00	1
2	RAILROAD , UT	CANYON COMP , WY	138.00	138.00	Wood - H	17.00		1
3	CENTRAL (UAMPS) #1 , UT	SAINT GEORGE , UT	138.00	138.00	Steel - SP	20.00		1
4	CENTRAL (UAMPS) #2 , UT	SAINT GEORGE , UT	138.00	138.00	Steel - SP		20.00	1
5	RED BUTTE , UT	SAINT GEORGE , UT	138.00	138.00		1.00		1
6	RED BUTTE , UT	WEST CEDAR , UT	138.00	138.00	Wood - H	50.00		1
7	RIVERDALE , UT	EAST LAYTON , UT	138.00	138.00	Steel - SP		6.00	1
8	SHICK , UT	PARRISH , UT	138.00	138.00	Wood - H		10.00	1
9	SILVER CREEK , UT	JORDANELLE , UT	138.00	138.00	Wood - SP	10.00		1
10	SPANISH FORK , UT	TANNER , UT	138.00	138.00	Wood - H	10.00		1
11	SUNRISE , UT	OQUIRRH , UT	138.00	138.00	Wood - SP		2.00	1
12	SYRACUSE , UT	CLEARFIELD SOUTH , UT	138.00	138.00	Steel - SP	1.00		1
13	SYRACUSE , UT	PARRISH , UT	138.00	138.00	Steel Tower	15.00		1
14	SYRACUSE , UT	ANGEL #1 , UT	138.00	138.00	Steel Tower		9.00	1
15	TAP TO ANGEL NORTH , UT	TAP TO PARRISH , UT	138.00	138.00			13.00	1
16	TAYLORSVILLE , UT	90TH SOUTH , UT	138.00	138.00	Wood - SP	6.00	2.00	1
17	TERMINAL , UT	KENNECOTT , UT	138.00	138.00	Steel - SP	9.00		1
18	TERMINAL , UT	ROWLEY , UT	138.00	138.00	Wood - H	56.00		1
19	TERMINAL , UT	MIDVALLEY , UT	138.00	138.00	Wood - H	7.00		1
20	TERMINAL , UT	MIDVALLEY , UT	138.00	138.00	Wood - H	7.00		1
21	TERMINAL , UT	TOOELE , UT	138.00	138.00	Wood - H	24.00	6.00	1
22	TERMINAL , UT	WEST VALLEY , UT	138.00	138.00	Wood - SP	7.00		1
23	THREEMILE KNOLL , ID	GRACE #1 , ID	138.00	138.00	Wood - H	17.00		1
24	THREEMILE KNOLL , ID	GRACE #2 , ID	138.00	138.00	Wood - H	17.00		1
25	THREEMILE KNOLL , ID	MONSANTO #1 , ID	138.00	138.00	Wood - H	2.00		1
26	THREEMILE KNOLL , ID	MONSANTO #2 , ID	138.00	138.00	Steel - SP	2.00		1
27	TIMP #1 , UT	DYNAMO , UT	138.00	138.00	Steel - SP	2.00		1
28	TIMP #2 , UT	DYNAMO , UT	138.00	138.00			2.00	1
29	TIMP , UT	HALE , UT	138.00	138.00	Steel - SP	4.00		1
30	TIMP , UT	SPANISH FORK , UT	138.00	138.00	Wood - H	23.00		1
31	TREASURETON , ID	GRACE , ID	138.00	138.00	Steel Tower	25.00		1
32	TREASURETON , ID	GRACE #2 , ID	138.00	138.00			25.00	1
33	TREASURETON , ID	ONEIDA , ID	138.00	138.00	Wood - H	6.00		1
34	TRI-CITY , UT	SUNRISE , ID	138.00	138.00	Wood - SP	22.00		1
35	TRI-CITY , UT	BANGERTER , UT	138.00	138.00	Wood - SP	6.00	12.00	1
36					TOTAL	16,076.00	741.00	272

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

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 AAC 26/7								1
795 ACSR 26/7								2
1272 ACSR 45/7								3
1272 ACSR 45/7								4
1272 ACSR 45/7								5
397.5 ACSR 26/7								6
795 AAC 26/7								7
250 CUHD /12								8
795 AAC 26/7								9
1272 ACSR 45/7								10
								11
1272 ACSR 45/7								12
1272 ACSR 45/7								13
250 CUHD /12								14
795 AAC /37								15
795 AAC /37								16
795 AAC 26/7								17
795 AAC /37								18
1272 ACSR 45/7								19
1272 AAC /61								20
397.5 ACSR 26/7								21
								22
250 CUHD /12								23
1272 ACSR 45/7								24
1272 AAC /61								25
1272 ACSR 45/7								26
								27
								28
								29
								30
250 CUHD /12								31
250 CUHD /12								32
250 CUHD /12								33
								34
								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	TRI-CITY , UT	AMERICAN FORK , UT	138.00	138.00	Wood - H	15.00		1
2	WEST CEDAR , UT	THREE PEAKS , UT	138.00	138.00	Wood - SP	20.00		1
3	WEST VALLEY , UT	OQUIRRH , UT	138.00	138.00	Wood - H	7.00		1
4	WESTFIELD , UT	HALE , UT	138.00	138.00	Wood - H	14.00		1
5	WHEELON , UT	AMERICAN FALLS , ID	138.00	138.00	Wood - H	86.00		1
6	WHEELON #103 , UT	TREASURETON , ID	138.00	138.00	Steel Tower	29.00		1
7	WHEELON #104 , UT	TREASURETON , ID	138.00	138.00			29.00	1
8	WHEELON #105 , UT	TREASURETON , ID	138.00	138.00	Wood - H	29.00		1
9	138 kV costs and expenses							
10								
11	138 Kv Subtotal					1,986.00	256.00	137
12								
13	All 115 kV Lines					1,613.00		
14								
15	All 69 kV Lines					3,003.00		
16								
17	All 57 kV Lines					113.00		
18								
19	All 46 kV Lines					2,573.00		
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	16,076.00	741.00	272

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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
795 AAC 26/7								2
								3
795 AAC 26/7								4
250 CUHD /12								5
250 CUHD /12								6
250 CUHD /12								7
250 CUHD /12								8
	18,751,663	317,386,565	336,138,228	92,709	2,203,969	61,455	2,358,133	9
								10
	18,751,663	317,386,565	336,138,228	92,709	2,203,969	61,455	2,358,133	11
								12
	4,932,102	160,168,165	165,100,267	2,357	4,099,797	430,779	4,532,933	13
								14
	6,594,189	245,155,552	251,749,741	38,482	3,537,690	153,281	3,729,453	15
								16
	46,281	10,100,248	10,146,529		52,648	3,652	56,300	17
								18
	9,291,675	226,241,335	235,533,010	93,015	3,186,710	28,850	3,308,575	19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	180,557,171	2,596,399,120	2,776,956,291	285,237	20,575,947	1,497,301	22,358,485	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 Dixonville - Meridian 500-kV line is jointly owned by PacifiCorp and the Bonneville Power Administration ("the BPA"). Ownership of the line is as follows: PacifiCorp's 50.0%, the BPA 50.0%. Plant cost reported for this line reflects PacifiCorp'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.: 3 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.: 4 Column: a

See footnote on page 422 for column (a) line 3.

Schedule Page: 422 Line No.: 5 Column: a

See footnote on page 422 for column (a) line 3.

Schedule Page: 422 Line No.: 6 Column: a

The Alvey - Dixonville 500-kV line is jointly owned by PacifiCorp and the BPA. Ownership of the line is as follows: PacifiCorp 50.0%, the BPA 50.0%. Plant cost reported for this line reflects PacifiCorp'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.: 7 Column: a

See footnote on page 422 for column (a) line 3.

Schedule Page: 422 Line No.: 8 Column: a

The Colstrip 4 - Switchyard 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, 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 PacifiCorp's share.

Schedule Page: 422 Line No.: 9 Column: a

The Colstrip - Broadview A 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, 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 PacifiCorp's share.

Schedule Page: 422 Line No.: 10 Column: a

The Colstrip - Broadview B 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, 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 PacifiCorp's share.

Schedule Page: 422 Line No.: 11 Column: a

The Broadview - Townsend A 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, 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 PacifiCorp's share.

Schedule Page: 422 Line No.: 12 Column: a

The Broadview - Townsend B 500-kV line is jointly owned by PacifiCorp, NorthWestern Corporation, Puget Sound Energy, 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 PacifiCorp's share.

FOOTNOTE DATA

Schedule Page: 422 Line No.: 17 Column: i

1157.4 ACSR/TW 36/7

Schedule Page: 422 Line No.: 18 Column: i

1157.4 ACSR/TW 36/7

Schedule Page: 422.1 Line No.: 31 Column: a

A 1.5 mile segment of the Casper - Dave Johnston 230-kV line is jointly owned by PacifiCorp 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 PacifiCorp's share.

Schedule Page: 422.1 Line No.: 31 Column: i

1557 ACSS/TW 45/7

Schedule Page: 422.4 Line No.: 24 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 12 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 17 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.6 Line No.: 18 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 3 Column: a

The Central – St. George 138-kV line is jointly owned by PacifiCorp 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 PacifiCorp's share.

Schedule Page: 422.7 Line No.: 4 Column: a

See footnote on page 422.7 for column (a) line 3.

Schedule Page: 422.7 Line No.: 11 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.: 27 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 28 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 29 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 30 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 34 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.7 Line No.: 35 Column: i

1557.4 ACSR/TW 36/7

Schedule Page: 422.8 Line No.: 3 Column: i

1557.4 ACSR/TW 36/7

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Ashgrove, UT	Clover, UT	2.00	Wood - SP	12.00	2	2
2	Clover, UT	Nebo, UT	2.00	Wood - SP	12.00	2	2
3	Green Canyon Sub, UT	Nibley Sub, UT	6.00	Wood - SP	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		10.00		36.00	5	5

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ACSR	Vertical 10'	138		1,664,619	416,155		2,080,774	1
1272	ACSR	Vertical 10'	138						2
1272	ACSR	Vertical 12'	138		2,444,548	1,792,104		4,236,652	3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
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									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					4,109,167	2,208,259		6,317,426	44

Schedule Page: 424 Line No.: 1 Column: m
Includes costs for the 138-kV Clover, UT to Nebo, UT line designation.

Schedule Page: 424 Line No.: 1 Column: n
Includes costs for the 138-kV Clover, UT to Nebo, UT line designation.

Schedule Page: 424 Line No.: 2 Column: m
See footnote on page 424 for column (m) line 1.

Schedule Page: 424 Line No.: 2 Column: n
See footnote on page 424 for column (n) line 1.

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

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
7	3					13
4	3					14
9	3					15
12	1					16
2	3					17
4	1					18
30	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
1	3					28
1	1					29
1	3					30
9	3					31
2	3					32
2	3					33
6	3					34
1	1					35
6	3					36
1	3					37
2	3					38
20	1					39
6	6					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	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	COPCO #1 HYDRO PLANT	TRANSMISSION-ATTENDE	69.00	2.30	
15	COPCO #2 230 SUB	TRANSMISSION-ATTENDE	230.00	115.00	
16	COPCO #2 HYDRO PLANT	TRANSMISSION-ATTENDE	115.00	69.00	12.47
17	COPCO #2 SUB	TRANSMISSION-ATTENDE	115.00	69.00	12.47
18	AGER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
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	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
9	3					1
25	1					2
4	3					3
4	3					4
324	102					5
						6
						7
32	4					8
3	3					9
95	2					10
130	9					11
						12
						13
27	6	2				14
375	2					15
122	5	1				16
51	4					17
5	3					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
7	1					31
4	1					32
12	1					33
10	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	7.20	
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	

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
3	1					5
6	1					6
5	1					7
14	1					8
9	1					9
1	1					10
6	1					11
9	1					12
4	1					13
20	1					14
3	1					15
22	1					16
14	1					17
3	1					18
5	1					19
3	1					20
10	1					21
20	1					22
5	1					23
8	1					24
14	1					25
20	1					26
20	1					27
12	1					28
2	1					29
20	1					30
32	2					31
9	1					32
8	1					33
7	1					34
40	2					35
20	1					36
20	1					37
20	1					38
14	1					39
8	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	867.43	
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	AMPS SUB	TRANSMISSION-UNATTEN	230.00	69.00	12.47
24	ANTELOPE SUB	TRANSMISSION-UNATTEN	230.00	161.00	12.47
25	ASHTON PLANT	TRANSMISSION-UNATTEN	46.00	2.40	12.47
26	BIG GRASSY SUB	TRANSMISSION-UNATTEN	161.00	69.00	
27	BONNEVILLE SUB	TRANSMISSION-UNATTEN	161.00	69.00	
28	CONDA SUB	TRANSMISSION-UNATTEN	138.00	46.00	
29	FISH CREEK SUB	TRANSMISSION-UNATTEN	161.00	46.00	
30	FRANKLIN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
31	GOSHEN SUB	TRANSMISSION-UNATTEN	345.00	161.00	46.00
32	GRACE SUB	TRANSMISSION-UNATTEN	138.00	46.00	6.60
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	

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
5	1					1
12	1					2
12	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
721	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
75	1	1				23
445	3					24
18	3					25
67	1					26
67	1					27
67	1					28
25	3					29
75	1					30
763	8	1				31
217	2					32
233	3					33
6	2					34
40	2					35
30	1					36
76	2					37
168	3					38
700	1					39
534	2					40

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	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)	
3606	40	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

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CLEVELAND AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	CLOAKE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
3	COBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
4	COLISEUM SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
5	COLUMBIA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	57.00
6	COOS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
7	COQUILLE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
8	CREEK SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
9	CROOKED RIVER RANCH SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
10	CROWFOOT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	CULLY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
12	CULVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	DAIRY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
14	DALLAS SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
15	DALREED SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
16	DESCHUTES SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	DEVILS LAKE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
18	DIXON SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
19	DODGE BRIDGE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	DOWELL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	EASY VALLEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	EMPIRE SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	ENTERPRISE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	FERN HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
25	FIELDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	FOOTHILLS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	FRALEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	GARDEN VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
29	GAZLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	GLENDALE SUB	DISTRIBUTION-UNATTEN	230.00	12.47	
31	GLENEDEN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
32	GLIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	GOLD HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
34	GORDON HOLLOW SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
35	GOSHEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
36	GRANT STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
37	GRASS VALLEY SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
38	GREEN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	GRIFFIN CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	HAMAKER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
45	2					1
20	1					2
10	3					3
9	2					4
55	2	1				5
20	1					6
40	2					7
5	1					8
25	2					9
20	1					10
25	1					11
13	1					12
25	1					13
50	2					14
75	3					15
12	1					16
50	2					17
7	1					18
12	1					19
20	1					20
45	2					21
20	1					22
19	2					23
12	1					24
25	1					25
21	4					26
5	3					27
20	1					28
8	4					29
25	2					30
5	1					31
12	1					32
11	3					33
6	1					34
20	1					35
45	2					36
1	4					37
25	1					38
20	1					39
8	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	HARRISBURG SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
2	HENLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	HERMISTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	HILLVIEW SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	HINKLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	HOLLADAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	HOLLYWOOD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	HOOD RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	HORNET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	HUMBUG CREEK SUB	DISTRIBUTION-UNATTEN	67.00	12.50	
11	HUNTERS CIRCLE TEMP SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	ILLAHEE FLATS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	INDEPENDENCE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
14	JACKSONVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
15	JEFFERSON SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	JEROME PRAIRIE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
17	JORDAN POINT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
18	JOSEPH SUB	DISTRIBUTION-UNATTEN	20.80	12.47	
19	JUNCTION CITY SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
20	KENWOOD SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	KILLINGWORTH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	KNAPPA SVENSEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	LAKEPORT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	LANCASTER SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
25	LEBANON SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
26	LINCOLN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
27	LOCKHART SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
28	LYONS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
29	MADRAS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	MALLORY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	MARYS RIVER SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
32	MEDCO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
33	MEDFORD	DISTRIBUTION-UNATTEN	69.00	12.47	
34	MERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	MERRILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
36	MINAM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
37	MODOC SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	MORO SUB	DISTRIBUTION-UNATTEN	20.80	2.40	
39	MURDER CREEK SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
40	MYRTLE CREEK 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)	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)	
13	1					1
6	3					2
40	1					3
45	2					4
20	1					5
75	3					6
50	2					7
40	2					8
20	1					9
9	1					10
12	1					11
2	1					12
20	1					13
75	2					14
12	1					15
20	1					16
20	1					17
6	1	1				18
25	2					19
3	3					20
40	2					21
6	1					22
50	2					23
12	3					24
40	2					25
105	3					26
40	2					27
9	2					28
25	2					29
25	1					30
20	1					31
20	1					32
67	8					33
45	2					34
17	6					35
	1					36
6	3					37
2	3					38
100	4					39
14	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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	MYRTLE POINT SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	NELSCOTT SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
3	NEW O'BRIEN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	OAK KNOLL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	OAKLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	OREMET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	OVERPASS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	PALLETTE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
9	PARK STREET SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
10	PARKROSE SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
11	PENDLETON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	PILOT ROCK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	POWELL BUTTE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	PRINEVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	PROVOLT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	QUEEN AVE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
17	RED BLANKET SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
18	REDMOND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	RIDDLE SUB	DISTRIBUTION-UNATTEN	116.00	69.00	
20	RIDDLE VENEER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
21	ROGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
22	ROSEBURG SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
23	ROSS AVE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	ROXY ANN SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
25	RUCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	RUNNING Y SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
27	RUSSELLVILLE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
28	SCENIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
29	SCIO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	SEASIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	SELMA SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
32	SHASTA WAY SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
33	SHEVLIN PARK SUB	DISTRIBUTION-UNATTEN	69.00	12.50	
34	SIMTAG BOOSTER PUMP	DISTRIBUTION-UNATTEN	34.50	4.16	
35	SOUTH DUNES SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	SOUTHGATE SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
37	SPRAGUE RIVER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
38	STATE STREET SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
39	STAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	STEAMBOAT SUB	DISTRIBUTION-UNATTEN	115.00	7.20	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
9	1					1
4	1					2
9	1					3
45	2					4
8	1					5
75	2					6
45	2					7
1	1	1				8
40	2					9
39	2					10
46	7	1				11
22	2					12
6	1					13
50	2					14
11	3					15
50	2					16
2	3					17
50	2					18
50	2					19
25	1	1				20
25	2					21
50	2					22
9	3					23
25	1					24
9	1					25
9	1					26
45	2					27
70	3					28
8	1					29
40	2					30
9	1					31
2	3					32
25	1					33
19	2					34
9	1					35
20	1					36
7	3					37
40	2					38
55	2					39
	1					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	STEVENS ROAD SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
2	SUTHERLIN SUB	DISTRIBUTION-UNATTEN	115.00	12.00	
3	SWEET HOME SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
4	TAKELMA SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
5	TALENT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
6	TEXUM SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	TILLER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
8	TOLO SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	TURKEY HILL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	UMAPINE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	UMATILLA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	VERNON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
13	VILAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	VILLAGE GREEN SUB	DISTRIBUTION-UNATTEN	115.00	20.80	
15	VINE STREET SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
16	WALLOWA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
17	WARM SPRINGS SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
18	WARRENTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
19	WASCO SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
20	WECOMA BEACH SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
21	WESTERN KRAFT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	WESTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
23	WESTSIDE HYDRO/SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
24	WEYERHAUSER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	WHITE CITY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
26	WILLOW COVE SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
27	WINSTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	YEW AVENUE SUB	DISTRIBUTION-UNATTEN	115.00	12.50	
29	YOUNGS BAY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
30	Total		15477.27	2559.80	195.00
31	Number of Substations-180				
32					
33	ALBINA SUB	T/D-UNATTENDED	115.00	12.47	69.00
34	APPLEGATE SUB	T/D-UNATTENDED	115.00	69.00	12.47
35	ASHLAND MTN AVE SUB	T/D-UNATTENDED	115.00	69.00	12.47
36	BEND PLANT SUB	T/D-UNATTENDED	69.00	13.09	12.47
37	CAVE JUNCTION SUB	T/D-UNATTENDED	115.00	12.47	69.00
38	HAZELWOOD SUB	T/D-UNATTENDED	115.00	69.00	12.47
39	KNOTT SUB	T/D-UNATTENDED	115.00	12.47	57.00
40	MILE HI SUB	T/D-UNATTENDED	115.00	69.00	12.47

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
50	2					1
25	1					2
42	2					3
12	1					4
50	2					5
25	1					6
1	1					7
11	1					8
13	3					9
20	1					10
25	2					11
50	2					12
25	1					13
40	2					14
20	1					15
7	1					16
12	3					17
25	2					18
3	3					19
3	1					20
50	2					21
22	2					22
22	9					23
40	2					24
60	3					25
28	3					26
22	3					27
25	1					28
37	2					29
4575	346	6				30
						31
						32
177	9					33
65	2					34
70	2					35
31	3					36
70	2					37
132	4					38
163	5					39
39	4					40

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

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PILOT BUTTE SUB	T/D-UNATTENDED	230.00	69.00	12.47
2	SAGE ROAD SUB	T/D-UNATTENDED	115.00	12.47	
3	WINCHESTER SUB	T/D-UNATTENDED	115.00	12.47	69.00
4	Total		1334.00	420.44	338.82
5	Number of Substations-11				
6					
7	CLEARWATER #1 HYDRO PLANT	TRANSMISSION-ATTENDE	138.00	6.90	
8	FISH CREEK HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
9	JC BOYLE HYDRO	TRANSMISSION-ATTENDE	230.00	11.00	
10	LEMOLO #1 HYDRO	TRANSMISSION-ATTENDE	11.30	12.50	
11	LEMOLO #2 HYDRO	TRANSMISSION-ATTENDE	115.00	12.00	
12	PROSPECT 1 HYDRO	TRANSMISSION-ATTENDE	69.00	2.30	
13	PROSPECT 2 HYDRO	TRANSMISSION-ATTENDE	69.00	6.60	
14	PROSPECT 3 HYDRO	TRANSMISSION-ATTENDE	69.00	12.47	
15	TOKETEE HYDRO	TRANSMISSION-ATTENDE	115.00	6.90	
16	BEND HYDRO PLANT	TRANSMISSION-UNATTEN	4.16	2.40	
17	CALAPOOYA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
18	CHILOQUIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
19	COLD SPRINGS SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
20	COVE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
21	DAYS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
22	DIAMOND HILL SUB	TRANSMISSION-UNATTEN	230.00	69.00	
23	DIXONVILLE 115/230 SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
24	DIXONVILLE 500 SUB	TRANSMISSION-UNATTEN	500.00	230.00	
25	EAGLE POINT HYDRO	TRANSMISSION-UNATTEN	115.00	2.40	
26	EAST SIDE HYDRO	TRANSMISSION-UNATTEN	46.00	12.47	
27	FISH HOLE SUB	TRANSMISSION-UNATTEN	115.00	69.00	
28	FRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
29	GRANTS PASS SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
30	GREEN SPRINGS PLANT/SUB	TRANSMISSION-UNATTEN	115.00	69.00	
31	HURRICANE SUB	TRANSMISSION-UNATTEN	230.00	69.00	2.40
32	ISTHMUS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
33	KENNEDY SUB	TRANSMISSION-UNATTEN	69.00	57.00	
34	KLAMATH FALLS SUB	TRANSMISSION-UNATTEN	230.00	69.00	
35	LONE PINE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
36	MALIN SUB	TRANSMISSION-UNATTEN	500.00	230.00	69.00
37	MERIDIAN SUB	TRANSMISSION-UNATTEN	500.00	230.00	
38	MONPAC SUB	TRANSMISSION-UNATTEN	115.00	69.00	
39	NICKEL MOUNTAIN SUB	TRANSMISSION-UNATTEN	230.00	115.00	
40	PARRISH GAP SUB	TRANSMISSION-UNATTEN	230.00	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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
400	4					1
40	2					2
75	5					3
1262	42					4
						5
						6
17	3					7
13	3					8
89	2	1				9
2	3	1				10
40	4					11
5	3					12
40	6	1				13
10	6					14
50	9					15
30	3					16
75	1					17
119	4					18
66	2					19
67	3					20
50	1					21
75	1					22
343	6					23
650	3					24
3	1					25
3	3					26
7	3					27
500	2					28
473	5					29
19	3					30
29	2					31
250	1					32
33	1					33
251	6	1				34
733	10					35
775	4	1				36
1300	6	1				37
50	1					38
114	1					39
150	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	PONDEROSA SUB	TRANSMISSION-UNATTEN	230.00	115.00	
2	PROSPECT CENTRAL SUB	TRANSMISSION-UNATTEN	115.00	69.00	
3	ROBERTS CREEK SUB	TRANSMISSION-UNATTEN	115.00	69.00	
4	SLIDE CREEK HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
5	SODA SPRINGS HYDRO	TRANSMISSION-UNATTEN	115.00	7.00	
6	TROUTDALE SUB	TRANSMISSION-UNATTEN	230.00	115.00	69.00
7	TUCKER SUB	TRANSMISSION-UNATTEN	115.00	69.00	
8	WALLOWA FALLS HYDRO	TRANSMISSION-UNATTEN	20.80		
9	Total		7401.26	2856.84	431.27
10	Number of Substations-42				
11					
12	UTAH				
13	106TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
14	118TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	23RD ST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	70TH SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	ALTAVIEW SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	AMALGA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	AMERICAN FORK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	ARAGONITE	DISTRIBUTION-UNATTEN	46.00	7.20	
21	AURORA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	BANGERTER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
23	BEAR RIVER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	BENJAMIN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	BINGHAM SUB	DISTRIBUTION-UNATTEN	46.00	7.62	
26	BLUE CREEK	DISTRIBUTION-UNATTEN	46.00	12.47	
27	BLUFF SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	BLUFFDALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	BOTHWELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	BRIAN HEAD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	BRICKYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	BRIGHTON SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
33	BROOKLAWN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	BRUNSWICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	BURTON SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
36	BUSH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	CANNON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	CANYONLANDS SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	CAPITOL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	CARBIDE SUB	DISTRIBUTION-UNATTEN	46.00	7.20	

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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.
250	1					1
46	4					2
50	1					3
21	3					4
13	3					5
500	3					6
100	2					7
2	3					8
7413	133	6				9
						10
						11
						12
30	1					13
30	1					14
12	1					15
30	1					16
45	2					17
11	1					18
30	1					19
1	1					20
3	1					21
50	2					22
17	2					23
2	1					24
25	1					25
2	3					26
1	3					27
9	1					28
4	1					29
14	1					30
9	1					31
26	2					32
6	1					33
60	3					34
11	3					35
9	1					36
12	1					37
1	1					38
20	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	CARBONVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	CARLISLE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
3	CASTO SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
4	CENTERVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
5	CENTRAL SUB	DISTRIBUTION-UNATTEN	43.80	12.47	
6	CHAPEL HILL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	CHERRYWOOD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	CIRCLEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	CLEAR CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	CLEAR LAKE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
11	CLEARFIELD SOUTH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	CLINTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
13	CLIVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	COALVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	COLD WATER CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
16	COLEMAN SUB	DISTRIBUTION-UNATTEN	138.00	69.00	12.47
17	COLTON WELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	COMMERCE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
19	COPPER HILLS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	CORINNE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	COVE FORT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	COZYDALE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
23	CROSS HOLLOW SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
24	CUDAHY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	DAMMERON VALLEY SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
26	DECKER LAKE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	DELLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	DELTA SUB	DISTRIBUTION-UNATTEN	46.00	69.00	
29	DESERET SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
30	DEWEYVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	DIMPLE DELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
32	DIXIE DEER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
33	DRAPER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	EAST BENCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
35	EAST HYRUM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	EAST LAYTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	EAST MILLCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	EDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	ELBERTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	ELK MEADOWS 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
6	1					1
30	1					2
25	1					3
22	1					4
9	1					5
30	1					6
50	2					7
3	1					8
4	1					9
	3					10
60	2					11
50	2					12
4	1					13
6	1					14
30	1					15
106	4					16
1	3					17
30	1					18
30	1					19
3	1					20
2	3					21
30	1					22
22	1					23
30	1					24
42	1					25
55	2					26
6	1					27
48	3					28
2	1					29
4	1					30
60	2					31
2	1					32
23	2					33
30	1					34
6	1					35
60	2					36
20	1					37
19	2					38
5	1					39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	ELSINORE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	EMERY CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	EMIGRATION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	ENOCH SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	ENTERPRISE VALLEY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	EUREKA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	FARMINGTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	FAYETTE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	FERRON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
10	FIELDING SUB	DISTRIBUTION-UNATTEN	46.00	12.00	
11	FIFTH WEST SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	FLUX SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	FOOL CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	FOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	FREEDOM SUBSTATION	DISTRIBUTION-UNATTEN	46.00	7.20	
16	FRUIT HEIGHTS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	GARDEN CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	GATEWAY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	GOLD RUSH SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
20	GORDON AVENUE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
21	GOSHEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	GRANGER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	GRANTSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	GUNLOCK HYDRO	DISTRIBUTION-UNATTEN	34.50	2.30	
25	GUNNISON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	HAMMER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	HAVASU SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	HELPER CITY SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
29	HENEFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	HERRIMAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
31	HIAWATHA SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
32	HIGHLAND DIST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	HOGGARD SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
34	HOGLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	HOLDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	HOLLADAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	HUNTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	HUNTINGTON CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
39	IRON MOUNTAIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
40	IRONTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	1					1
3	3					2
25	1					3
14	1					4
10	1					5
3	1					6
30	1					7
1	2					8
5	1					9
6	1					10
50	2					11
4	1					12
2	1					13
7	1					14
	1					15
22	1					16
12	1					17
28	1	1				18
30	1					19
30	1					20
2	1					21
50	2					22
23	1					23
1	1					24
11	2					25
60	2					26
3	1					27
3	3					28
4	1					29
30	1					30
4	3					31
25	1					32
50	2					33
22	1					34
4	1					35
32	2					36
22	1					37
12	2					38
1	1					39
2	1					40

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	IVINS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
2	JORDAN NARROWS SUB	DISTRIBUTION-UNATTEN	46.00	2.40	
3	JORDAN PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
4	JORDANELLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	JUAB SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	JUNCTION SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
7	KAIBAB SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
8	KAMAS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	KEARNS SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
10	KENSINGTON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
11	LAKE PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
12	LARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	LAYTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	LEGRANDE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	LEWISTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	LINCOLN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	LINDON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	LISBON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
19	LOAFER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
20	LOGAN CANYON SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
21	LONE TREE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
22	LOWER BEAVER SUB	DISTRIBUTION-UNATTEN	46.00	6.60	
23	LYNNDYL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	MAESER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	MAGNA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	MANILA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
27	MANTUA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	MAPLETON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	MARRIOTT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	MARYSVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	MATHIS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	MCCORNICK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	MCKAY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	MEADOWBROOK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	46.00
35	MEDICAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	MIDLAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	MIDVALE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	MILFORD TV SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
40	MINERSVILLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	

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SUBSTATIONS (Continued)

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22	1					1
13	2					2
30	1					3
30	1					4
2	3					5
3	1					6
5	1					7
7	1					8
60	2					9
7	1					10
53	2					11
6	1					12
40	2					13
2	1					14
14	1					15
20	1					16
20	1					17
4	1					18
	1					19
1	1					20
20	1					21
1	1					22
4	1					23
12	1					24
30	1					25
22	1					26
2	1					27
14	1					28
20	1					29
3	1					30
9	1					31
6	1					32
20	1					33
42	2					34
57	4					35
30	1					36
25	1					37
14	1					38
	1					39
2	1					40

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

SUBSTATIONS

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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	MOAB CITY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	MONTEZUMA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
3	MOORE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
4	MORGAN SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
5	MORONI SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	MOSS JUNCTION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	MOUNTAIN DELL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	MOUNTAIN GREEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	MYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	NEW HARMONY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
11	NEWGATE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	NEWTON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	NIBLEY SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
14	NORTH BENCH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
15	NORTH FIELDS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	NORTH LOGAN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	NORTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	NORTH SALT LAKE SUB	DISTRIBUTION-UNATTEN	46.00	13.20	
19	NORTHEAST SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
20	NORTHRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	OAKLAND AVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
22	OAKLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	OLYMPUS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	OPHIR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	ORANGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
26	ORANGEVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
27	OREM SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	PACK CREEK RESERVOIR	DISTRIBUTION-UNATTEN	46.00	12.47	
29	PANGUITCH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
30	PARIETTE SUBSTATION	DISTRIBUTION-UNATTEN	69.00	24.90	
31	PARK CITY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	PARKWAY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
33	PARLEYS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
34	PELICAN POINT SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	PINE CANYON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
36	PINE CREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	PINNACLE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
38	PLAIN CITY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	PLEASANT GROVE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	PLEASANT VIEW 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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
19	2					1
12	1					2
3	1					3
7	2					4
6	1					5
6	3					6
5	1					7
6	1					8
6	1					9
7	1					10
20	1					11
5	1					12
14	1					13
25	1					14
2	1					15
25	1					16
22	1					17
25	1					18
45	2					19
14	1					20
24	2					21
6	1					22
22	1					23
3	1					24
20	1					25
14	1					26
48	2					27
4	1					28
5	1					29
4	3					30
35	2					31
50	2					32
16	2					33
6	1					34
55	2					35
2	1					36
14	1					37
22	1					38
25	1					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	PORTER ROCKWELL SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
2	PROMONTORY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	QUAIL CREEK SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
4	QUARRY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	QUICHAPA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
6	RAINS SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
7	RANDOLPH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
8	RASMUSON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	RATTLESNAKE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
10	RED MOUNTAIN SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
11	RED ROCK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
12	REDWOOD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	RESEARCH PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	RICH SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
15	RICHFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	RICHMOND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	RIDGELAND SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
18	RITER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	ROCK CANYON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
20	ROCKVILLE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
21	ROCKY POINT	DISTRIBUTION-UNATTEN	138.00	13.20	
22	ROSE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
23	ROYAL SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
24	SALINA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
25	SANDY SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
26	SARATOGA SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
27	SCIPIO SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	SCOFIELD RESERVOIR SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
29	SCOFIELD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
30	SECOND STREET SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	SEVEN MILE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	SHARON SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
33	SHIVWITS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
34	SHORELINE SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
35	SIXTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	SKULL VALLEY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
37	SKYPARK SUB	DISTRIBUTION-UNATTEN	138.00	12.50	12.50
38	SNARR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
39	SNOWVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
40	SNYDERVILLE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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.
30	1					1
2	1					2
4	1					3
60	2					4
4	1					5
15	1					6
2	1					7
1	3					8
14	1					9
12	1					10
3	1					11
45	2					12
45	2					13
5	1					14
22	2					15
11	1					16
40	2					17
20	1					18
5	1					19
4	1					20
30	1					21
24	3					22
	3					23
11	1					24
60	2					25
60	2					26
1	3					27
1	1					28
1	3					29
13	2					30
	1					31
20	1					32
6	1					33
60	2					34
20	1					35
2	1					36
40	1					37
40	2					38
5	1					39
60	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	SOLDIER SUMMIT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	SOUTH JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
3	SOUTH MILFORD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	SOUTH MOUNTAIN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	SOUTH OGDEN SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
6	SOUTH PARK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
7	SOUTH WEBER SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
8	SOUTHWEST SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
9	SPANISH VALLEY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	SPRINGDALE SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
11	ST. JOHNS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	STAIRS SUB	DISTRIBUTION-UNATTEN	12.47	2.40	
13	STANSBURY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
14	SUMMIT CREEK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
15	SUMMIT PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
16	SUNRISE SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
17	SUPERIOR SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	SUTHERLAND SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
19	TAMARISK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
20	TAYLOR SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
21	THIEF CREEK SUB	DISTRIBUTION-UNATTEN	138.00	24.90	
22	THIRD WEST SUB	DISTRIBUTION-UNATTEN	138.00	13.20	
23	THIRTEENTH SOUTH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
24	THOMPSON SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
25	TOOELE DEPOT SUB	DISTRIBUTION-UNATTEN	46.00	12.50	
26	TOQUERVILLE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	34.50
27	UINTAH SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
28	UNION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
29	UNIVERSITY SUB	DISTRIBUTION-UNATTEN	46.00	7.20	12.50
30	VALLEY CENTER SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
31	VERMILLION SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
32	VERNAL SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
33	VEYO HYDRO	DISTRIBUTION-UNATTEN	34.50	2.40	
34	VICKERS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
35	VINEYARD SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
36	WALLSBURG SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
37	WALNUT GROVE SUB	DISTRIBUTION-UNATTEN	138.00	12.50	
38	WARREN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
39	WASATCH STATE PARK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
40	WASHAKIE SUB	DISTRIBUTION-UNATTEN	138.00	4.16	

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
12	1					1
60	2					2
20	2					3
60	2					4
25	1					5
30	1					6
22	1					7
22	2					8
6	1					9
4	1					10
4	1					11
2	1					12
20	1					13
14	1					14
7	1					15
60	2					16
8	1					17
6	1					18
20	1					19
14	1					20
14	1					21
100	2					22
22	1					23
2	1					24
25	1					25
34	2					26
39	2					27
50	2					28
29	2					29
22	1					30
3	1					31
32	2					32
2	3					33
2	1					34
25	1					35
13	1					36
30	1					37
30	1					38
2	3					39
14	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	WELBY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	WELFARE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
3	WEST COMMERCIAL SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
4	WEST JORDAN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
5	WEST OGDEN SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
6	WEST ROY SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
7	WEST TEMPLE SUB	DISTRIBUTION-UNATTEN	46.00	4.16	
8	WESTWATER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
9	WHITE MESA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	WHITE ROCK SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
11	WILLOWCREEK SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
12	WILLOWRIDGE SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
13	WINCHESTER HILLS SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
14	WINKLEMAN SUB	DISTRIBUTION-UNATTEN	46.00	7.20	
15	WOLF CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
16	WOOD CROSS SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
17	WOODRUFF SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
18	Total		19675.27	3564.73	117.97
19	Number of Substations-285				
20					
21	90TH SOUTH SUB	T/D-UNATTENDED	345.00	138.00	12.47
22	ANGEL SUB	T/D-UNATTENDED	138.00	12.47	46.00
23	BDO SUBSTATION	T/D-UNATTENDED	138.00	12.47	
24	BUTLERVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
25	CENTENNIAL SUB	T/D-UNATTENDED	138.00	12.47	
26	COTTONWOOD SUB	T/D-UNATTENDED	138.00	12.47	46.00
27	DECADE SUB	T/D-UNATTENDED	138.00	12.50	
28	DUMAS SUB	T/D-UNATTENDED	138.00	12.47	
29	EMMA PARK SUBSTATION	T/D-UNATTENDED	138.00	12.47	
30	GROW SUB	T/D-UNATTENDED	138.00	12.47	46.00
31	HALE SUB	T/D-UNATTENDED	138.00	46.00	12.47
32	HIGHLAND SUB	T/D-UNATTENDED	138.00	12.47	46.00
33	JORDAN SUB	T/D-UNATTENDED	138.00	46.00	12.47
34	JUDGE SUB	T/D-UNATTENDED	46.00	12.47	
35	MCCLELLAND SUB	T/D-UNATTENDED	138.00	46.00	12.47
36	MORTON COURT SUB	T/D-UNATTENDED	138.00	12.47	
37	OQUIRRH SUB	T/D-UNATTENDED	345.00	46.00	138.00
38	PARRISH SUB	T/D-UNATTENDED	138.00	12.47	46.00
39	PIONEER PLANT	T/D-UNATTENDED	138.00	2.30	46.00
40	RIVERDALE SUB	T/D-UNATTENDED	138.00	46.00	12.47

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS (Continued)

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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)	
42	2					1
5	1					2
22	1					3
28	1					4
60	2					5
25	1					6
60	3					7
5	1					8
14	1					9
30	1					10
1	1					11
14	1					12
4	1					13
	1					14
6	1					15
20	1					16
2	1					17
5463	393	1				18
						19
						20
1572	5	1				21
135	3					22
30	1					23
205	4					24
40	2					25
289	7					26
60	2					27
60	2					28
8	1					29
72	3					30
114	2					31
97	2					32
164	2					33
22	1					34
340	3					35
65	2					36
835	4	1				37
97	2					38
51	7					39
180	3					40

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PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SEVIER SUB	T/D-UNATTENDED	138.00	46.00	12.47
2	SILVER CREEK SUB	T/D-UNATTENDED	138.00	12.47	46.00
3	SOUTHEAST SUB	T/D-UNATTENDED	138.00	12.47	46.00
4	SPHINX SUB	T/D-UNATTENDED	46.00	12.47	
5	SYRACUSE SUB	T/D-UNATTENDED	345.00	46.00	138.00
6	TAYLORSVILLE SUB	T/D-UNATTENDED	138.00	46.00	12.47
7	TERMINAL SUB	T/D-UNATTENDED	345.00	46.00	138.00
8	TIMP SUB	T/D-UNATTENDED	138.00	46.00	12.47
9	TOOELE SUB	T/D-UNATTENDED	138.00	46.00	12.47
10	TRI CITY SUB	T/D-UNATTENDED	138.00	12.47	
11	WEST VALLEY SUB	T/D-UNATTENDED	138.00	12.47	
12	WESTFIELD SUB	T/D-UNATTENDED	138.00	12.47	
13	Total		5060.00	916.79	906.70
14	Number of Substations-32				
15					
16	EMERY SUB	TRANSMISSION-ATTENDE	345.00	138.00	69.00
17	GADSBY SUB	TRANSMISSION-ATTENDE	138.00	46.00	
18	HUNTER PLANT	TRANSMISSION-ATTENDE	345.00	23.00	
19	HUNTINGTON PLANT	TRANSMISSION-ATTENDE	345.00	23.00	
20	ABAJO SUB	TRANSMISSION-UNATTEN	138.00	69.00	
21	ASHLEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
22	BARNEY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
23	BEN LOMOND SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
24	BLACKHAWK SUB	TRANSMISSION-UNATTEN	138.00	69.00	46.00
25	BOOKCLIFFS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
26	CAMERON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
27	CAMP WILLIAMS SUB	TRANSMISSION-UNATTEN	345.00	138.00	12.47
28	CARBON SUB	TRANSMISSION-UNATTEN	138.00		
29	CLOVER SUB	TRANSMISSION-UNATTEN	345.00	138.00	14.40
30	COLUMBIA SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
31	CRANER FLAT SUB	TRANSMISSION-UNATTEN	138.00	12.47	
32	CUTLER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
33	EL MONTE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
34	GARKANE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
35	GREEN CANYON SUB	TRANSMISSION-UNATTEN	138.00	46.00	
36	GRINDING SUB	TRANSMISSION-UNATTEN	138.00	13.80	
37	HELPER SUB	TRANSMISSION-UNATTEN	138.00	46.00	
38	HONEYVILLE SUB	TRANSMISSION-UNATTEN	138.00	46.00	
39	HORSESHOE SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
40	HUNTINGTON SUB	TRANSMISSION-UNATTEN	345.00	138.00	

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.
34	4					1
100	2					2
50	2					3
3	1	3				4
600	5					5
358	4					6
1108	6	2				7
130	2					8
158	3					9
30	1					10
30	1					11
20	1					12
7057	90	7				13
						14
						15
783	13	1				16
318	2					17
1513	5	1				18
981	4					19
67	1					20
133	2					21
100	1					22
1813	5					23
100	2					24
6	3	1				25
25	4					26
169	2					27
8	1					28
448	1					29
71	2					30
40	2					31
70	2					32
312	3					33
33	1					34
67	2					35
225	3					36
142	2					37
35	1					38
80	2					39
270	4					40

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2012/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	JERUSALEM SUB	TRANSMISSION-UNATTEN	138.00	46.00	
2	LAMPO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
3	MCFADDEN SUB	TRANSMISSION-UNATTEN	138.00	46.00	
4	MIDDLETON SUB	TRANSMISSION-UNATTEN	138.00	69.00	34.50
5	MIDVALLEY SUB	TRANSMISSION-UNATTEN	345.00	138.00	
6	MIDWAY CITY SUB	TRANSMISSION-UNATTEN	138.00	46.00	
7	MINERAL PRODUCTS SUB	TRANSMISSION-UNATTEN	69.00	46.00	
8	MOAB SUB	TRANSMISSION-UNATTEN	138.00	69.00	
9	NEBO SUB	TRANSMISSION-UNATTEN	138.00	46.00	
10	OLMSTED SUB	TRANSMISSION-UNATTEN	46.00	2.40	
11	PAROWAN VALLEY SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
12	PAVANT SUB	TRANSMISSION-UNATTEN	230.00	46.00	
13	PINTO SUB	TRANSMISSION-UNATTEN	345.00	138.00	69.00
14	RED BUTTE SUB	TRANSMISSION-UNATTEN	230.00	138.00	
15	SAND COVE HYDRO	TRANSMISSION-UNATTEN	34.50	2.40	
16	SIGURD SUB	TRANSMISSION-UNATTEN	345.00	230.00	138.00
17	SMITHFIELD SUB	TRANSMISSION-UNATTEN	138.00	46.00	12.47
18	SPANISH FORK SUB	TRANSMISSION-UNATTEN	345.00	138.00	46.00
19	ST GEORGE SUB	TRANSMISSION-UNATTEN	138.00	16.50	
20	THREE PEAKS SUB	TRANSMISSION-UNATTEN	345.00	138.00	
21	WEBER PLANT/SUB	TRANSMISSION-UNATTEN	46.00	2.30	
22	WEST CEDAR SUB	TRANSMISSION-UNATTEN	230.00	138.00	34.50
23	Total		8843.50	3315.87	673.78
24	Number of Substations-47				
25					
26	WASHINGTON				
27	ATTALIA SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
28	BOWMAN SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
29	CASCADE KRAFT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	4.16
30	CLINTON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
31	DAYTON SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
32	DODD ROAD SUB	DISTRIBUTION-UNATTEN	69.00	20.80	
33	GRANDVIEW SUB	DISTRIBUTION-UNATTEN	115.00	12.47	69.00
34	HOPLAND SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
35	NACHES HYDRO	DISTRIBUTION-UNATTEN	115.00	12.47	
36	NOB HILL SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
37	NORTH PARK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
38	ORCHARD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
39	PACIFIC SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
40	POMEROY 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.
67	1					1
75	1					2
45	1					3
141	4					4
900	2					5
67	1					6
12	1					7
67	1					8
67	1					9
15	1					10
138	2					11
133	2					12
258	3					13
400	1					14
	1					15
1124	6					16
63	2					17
1017	5					18
100	3	1				19
450	1					20
7	1					21
262	3					22
13217	114	4				23
						24
						25
						26
25	1					27
45	2					28
118	6					29
25	1					30
23	2					31
25	4					32
42	2					33
50	2					34
20	1					35
42	2					36
45	2					37
50	2					38
28	3					39
9	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	PROSPECT POINT SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	PUNKIN CENTER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
3	RIVER ROAD SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
4	SELAH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
5	SULPHUR CREEK SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	SUNNYSIDE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
7	TIETON SUB	DISTRIBUTION-UNATTEN	115.00	12.47	34.50
8	TOPPENISH SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
9	TOUCHET SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
10	VOELKER SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
11	WAITSBURG SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
12	WAPATO SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
13	WENAS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
14	WHITE SWAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
15	WILEY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
16	Total		2921.00	369.96	107.66
17	Number of Substations-29				
18					
19	CENTRAL SUB	T/D-UNATTENDED	69.00	12.47	
20	MILL CREEK SUB	T/D-UNATTENDED	69.00	12.47	
21	UNION GAP SUB	T/D-UNATTENDED	230.00	115.00	12.47
22	Total		368.00	139.94	12.47
23	Number of Substations-3				
24					
25	MERWIN HYDRO PLANT	TRANSMISSION-ATTENDE	115.00	13.20	
26	YALE PLANT	TRANSMISSION-ATTENDE	115.00	13.80	
27	OUTLOOK SUB	TRANSMISSION-UNATTEN	230.00	115.00	
28	PASCO SUB	TRANSMISSION-UNATTEN	115.00	69.00	7.20
29	POMONA HEIGHTS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
30	WALLA WALLA 230KV SUB	TRANSMISSION-UNATTEN	230.00	69.00	
31	WALLULA SUB	TRANSMISSION-UNATTEN	230.00	69.00	
32	WINE COUNTRY SUB	TRANSMISSION-UNATTEN	230.00	115.00	
33	Total		1495.00	579.00	7.20
34	Number of Substations-8				
35					
36	WYOMING				
37	ANTELOPE MINE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
38	ASTLE STREET	DISTRIBUTION-UNATTEN	34.50	13.20	
39	BAILEY DOME SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
40	BAR X SUB	DISTRIBUTION-UNATTEN	230.00	34.50	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
40	2					1
20	2					2
51	4					3
45	2					4
25	1					5
45	2					6
29	2					7
50	2					8
6	1					9
25	1					10
9	1					11
45	2					12
25	2					13
22	2					14
45	2					15
1029	59					16
						17
						18
14	1					19
45	2					20
348	5					21
407	8					22
						23
						24
183	9	1				25
143	3	1				26
125	1					27
39	9					28
300	2					29
300	2					30
120	2					31
250	1					32
1460	29	2				33
						34
						35
						36
25	1					37
12	1					38
2	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	BIG MUDDY SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
2	BIG PINEY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
3	BLACKS FORK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
4	BRIDGER PUMP SUB	DISTRIBUTION-UNATTEN	230.00	34.50	13.20
5	BRYAN SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
6	BUFFALO TOWN SUB	DISTRIBUTION-UNATTEN	20.80	4.16	
7	BYRON SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
8	CASSA SUB	DISTRIBUTION-UNATTEN	57.00	20.80	12.47
9	CENTER STREET SUB	DISTRIBUTION-UNATTEN	115.00	4.16	
10	CHAPMAN SUBSTATION	DISTRIBUTION-UNATTEN	46.00	12.47	
11	CHUKAR SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
12	CHURCH AND DWIGHT SUB	DISTRIBUTION-UNATTEN	34.50	0.48	
13	COKEVILLE SUB	DISTRIBUTION-UNATTEN	46.00	24.90	
14	COLUMBIA-GENEVA SUB	DISTRIBUTION-UNATTEN	230.00	13.80	
15	COMMUNITY PARK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
16	CROOKS GAP SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
17	DEER CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
18	DJ COAL MINE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
19	DOUGLAS SUB	DISTRIBUTION-UNATTEN	57.00	2.30	
20	DRY FORK SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
21	ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	7.20	
22	EMIGRANT SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
23	EVANS SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
24	EVANSTON SUB	DISTRIBUTION-UNATTEN	138.00	12.47	
25	FORT CASPER SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
26	FORT SANDERS SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
27	FRANNIE SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
28	FRONTIER SUB	DISTRIBUTION-UNATTEN	69.00	4.16	
29	GARLAND SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
30	GLENDO SUB	DISTRIBUTION-UNATTEN	57.00	4.16	
31	GRASS CREEK SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
32	GREAT DIVIDE SUB	DISTRIBUTION-UNATTEN	115.00	34.50	
33	GREYBULL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
34	HANNA SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
35	JACKALOPE SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
36	KEMMERER SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
37	KIRBY CREEK PUMPING STATION	DISTRIBUTION-UNATTEN	34.50	2.40	
38	KIRBY CREEK SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
39	LANDER SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
40	LARAMIE SUB	DISTRIBUTION-UNATTEN	115.00	13.20	

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7	1					1
14	1					2
150	2					3
72	4					4
25	1					5
2	3					6
2	3					7
2	6	1				8
12	1					9
4	1					10
1	3					11
3	2					12
4	1					13
45	2					14
50	2					15
5	3					16
9	1					17
12	1					18
6	3					19
9	1					20
5	1					21
12	1					22
9	1					23
40	2					24
25	1					25
20	1					26
50	2					27
6	1					28
45	2					29
3	4					30
25	1					31
20	1					32
3	1					33
6	1					34
25	1					35
10	1					36
3	3					37
2	3					38
25	2					39
50	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	LATHAM SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
2	LINCH SUB	DISTRIBUTION-UNATTEN	69.00	13.80	
3	LITTLE MOUNTAIN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
4	LOVELL SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
5	MILL IRON SUB	DISTRIBUTION-UNATTEN	34.50	13.80	
6	MILLS SUB	DISTRIBUTION-UNATTEN	12.47	4.16	
7	MURPHY DOME SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
8	NUGGETT SUB	DISTRIBUTION-UNATTEN	69.00	7.20	
9	OPAL SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
10	ORIN SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
11	ORPHA SUB	DISTRIBUTION-UNATTEN	57.00	7.20	
12	PARADISE SUB	DISTRIBUTION-UNATTEN	69.00	25.00	
13	PARCO SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
14	PINEDALE SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
15	PITCHFORK SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
16	POISON SPIDER SUB	DISTRIBUTION-UNATTEN	69.00	2.40	
17	POLECAT SUB	DISTRIBUTION-UNATTEN	34.50	12.47	
18	RAINBOW SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
19	RAVEN SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
20	RED BUTTE SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
21	REFINERY SUB	DISTRIBUTION-UNATTEN	115.00	12.47	
22	SAGE HILL SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
23	SHOSHONI SUB	DISTRIBUTION-UNATTEN	34.50	2.40	
24	SLATE CREEK SUB	DISTRIBUTION-UNATTEN	69.00	12.47	
25	SOUTH CODY SUB	DISTRIBUTION-UNATTEN	69.00	24.90	
26	SOUTH ELK BASIN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
27	SOUTH TRONA SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
28	SPRING CREEK SUB	DISTRIBUTION-UNATTEN	115.00	13.20	
29	SVILAR SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
30	TEN MILE STEP DOWN SUB	DISTRIBUTION-UNATTEN	34.50	12.50	
31	TEN MILE SUB	DISTRIBUTION-UNATTEN	69.00	34.50	
32	THERMOPOLIS TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
33	THUNDER CREEK SUB	DISTRIBUTION-UNATTEN	57.00	12.47	
34	VETERANS SUB	DISTRIBUTION-UNATTEN	34.50	13.20	
35	WELCH SUB	DISTRIBUTION-UNATTEN	57.00	2.40	
36	WERTZ-SINCLAIR SUB	DISTRIBUTION-UNATTEN	57.00	4.16	12.50
37	WEST ADAMS SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
38	WESTVACO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	
39	WORLAND TOWN SUB	DISTRIBUTION-UNATTEN	34.50	4.16	
40	WYOPO SUB	DISTRIBUTION-UNATTEN	230.00	34.50	

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
12	1					2
20	1					3
4	1					4
12	1	1				5
1	3					6
5	1					7
	1					8
7	1					9
2	3					10
3	3					11
30	1					12
5	1					13
8	1					14
17	9	2				15
3	1					16
2	3					17
12	1					18
200	2					19
20	1					20
45	2					21
6	1					22
2	3					23
1	1					24
14	3	1				25
2	6					26
150	2					27
25	1					28
2	3					29
5	1					30
12	1					31
5	1					32
9	1					33
25	2					34
3	3					35
2	6					36
3	1					37
25	1					38
5	1					39
20	1	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	WYUTA SUB	DISTRIBUTION-UNATTEN	46.00	12.47	
2	Total		7493.24	1311.37	38.17
3	Number of Substations-85				
4					
5	BUFFALO SUB	T/D-UNATTENDED	230.00	20.80	
6	ELK HORN SUB	T/D-UNATTENDED	115.00	12.50	
7	FIREHOLE SUB	T/D-UNATTENDED	230.00	34.50	
8	HILLTOP SUB	T/D-UNATTENDED	115.00	34.50	20.80
9	LABARGE SUB	T/D-UNATTENDED	69.00	24.90	
10	POINT OF ROCKS SUB	T/D-UNATTENDED	230.00	34.50	
11	RIVERTON 230 SUB	T/D-UNATTENDED	230.00	12.47	34.50
12	YELLOWCAKE SUB	T/D-UNATTENDED	230.00	34.50	
13	Total		1449.00	208.67	55.30
14	Number of Substations-8				
15					
16	DAVE JOHNSTON PLANT/SUB	TRANSMISSION-ATTENDE	230.00	115.00	69.00
17	JIM BRIDGER 345KV SUB	TRANSMISSION-ATTENDE	345.00	230.00	34.50
18	JIM BRIDGER UNITS 1-4	TRANSMISSION-ATTENDE	345.00	22.00	
19	NAUGHTON SUB	TRANSMISSION-ATTENDE	230.00	69.00	138.00
20	WYODAK 230KV SUB	TRANSMISSION-ATTENDE	230.00	69.00	
21	WYODAK PLANT	TRANSMISSION-ATTENDE	230.00	22.00	
22	BAIROIL SUB	TRANSMISSION-UNATTEN	115.00	34.50	57.00
23	CASPER SUB	TRANSMISSION-UNATTEN	230.00	115.00	13.20
24	CHAPPELL CREEK SUB	TRANSMISSION-UNATTEN	230.00	69.00	
25	CHIMNEY BUTTE SUB	TRANSMISSION-UNATTEN	230.00	69.00	
26	FOOTE CREEK WIND FARM	TRANSMISSION-UNATTEN	230.00	34.50	
27	GLENDO AUTO SUB	TRANSMISSION-UNATTEN	69.00	57.00	
28	MANSFACE SUB	TRANSMISSION-UNATTEN	230.00	34.50	
29	MIDWEST SUB	TRANSMISSION-UNATTEN	230.00	69.00	34.50
30	MINERS SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
31	MUSTANG SUB	TRANSMISSION-UNATTEN	230.00	115.00	
32	OREGON BASIN SUB	TRANSMISSION-UNATTEN	230.00	34.50	69.00
33	PLATTE SUB	TRANSMISSION-UNATTEN	230.00	115.00	34.50
34	RAILROAD SUB	TRANSMISSION-UNATTEN	230.00	138.00	
35	ROCK SPRINGS 230 SUB	TRANSMISSION-UNATTEN	230.00	34.50	
36	SAGE SUB	TRANSMISSION-UNATTEN	69.00	46.00	
37	THERMOPOLIS SUB	TRANSMISSION-UNATTEN	230.00	115.00	
38	Total		4853.00	1722.50	484.20
39	Number of Substations-22				
40					

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
1631	157	6				2
						3
						4
20	1					5
25	1					6
50	2					7
45	2	1				8
8	6					9
25	1					10
74	4					11
25	1					12
272	18	1				13
						14
						15
1358	16					16
1084	22					17
1122	2					18
1232	15	1				19
230	3					20
503	3	1				21
53	3					22
517	5					23
67	1					24
75	1					25
196	2					26
15	2					27
20	1					28
90	4					29
58	4	1				30
200	2					31
65	2					32
140	3					33
400	1					34
50	2					35
22	1					36
175	2					37
7672	97	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					
2	CALIFORNIA				
3	Distribution - 43				
4	T/D - 3				
5	Transmission - 9				
6					
7	IDAHO				
8	Distribution - 65				
9	T/D - 5				
10	Transmission - 18				
11					
12	MONTANA				
13	Transmission - 1				
14					
15	OREGON				
16	Distribution - 180				
17	T/D - 11				
18	Transmission - 42				
19					
20	UTAH				
21	Distribution - 285				
22	T/D - 32				
23	Transmission - 47				
24					
25	WASHINGTON				
26	Distribution - 29				
27	T/D - 3				
28	Transmission - 8				
29					
30	WYOMING				
31	Distribution - 85				
32	T/D - 8				
33	Transmission - 22				
34					
35	ALL STATES				
36	Distribution - 687				
37	T/D - 62				
38	Transmission - 147				
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
324						3
130						4
805						5
						6
						7
721						8
374						9
3606						10
						11
						12
100						13
						14
						15
4575						16
1262						17
7413						18
						19
						20
5463						21
7057						22
13217						23
						24
						25
1029						26
407						27
1460						28
						29
						30
1631						31
272						32
7672						33
						34
						35
13743						36
9502						37
34273						38
						39
						40

Schedule Page: 426.9 Line No.: 24 Column: a

The Dixonville 500kV Substation is jointly owned by PacifiCorp 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.: 36 Column: a

The Malin 500kV Substation is jointly owned by PacifiCorp, Portland General Electric ("PGE"), BPA and Western Area Power Administration ("WAPA"). Ownership of the substation is as follows: PacifiCorp 25.0%, PGE 25.0%, BPA 25.0% and WAPA 25.0%. Operation and maintenance costs are shared among the four parties and responsibility is as follows: PacifiCorp 25.0%, PGE 25.0%, BPA 25.0% and WAPA 25.0%.

Schedule Page: 426.9 Line No.: 37 Column: a

The Meridian 500kV Substation is jointly owned by PacifiCorp 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.: 16 Column: a

The Dave Johnston 230kV Substation is jointly owned by PacifiCorp 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.: 17 Column: a

The Jim Bridger 345kV Substation is jointly owned by PacifiCorp 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.: 20 Column: a

The Wyodak 230kV Substation is jointly owned by PacifiCorp and Black Hills Power. Ownership of the substation is as follows: PacifiCorp 80.0% and Black Hills Power 20.0%. Operation and maintenance costs are shared between the two parties and responsibility is as follows: PacifiCorp 80.0% and Black Hills Power 20.0%.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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				
3	Coal purchases and support services	Bridger Coal Company		149,861,924
4				
5	Coal mining services	Energy West Mining Company	151	65,093,351
6				
7	Coal purchases	Trapper Mining Inc.	151	13,669,844
8				
9	Administrative support services	Interwest Mining Company		822,352
10				
11	Administrative services under the IASA	MEHC		10,423,677
12	Administrative services under the IASA	MEC		3,881,498
13	Administrative services under the IASA	MHC, Inc.	426.5, 923	756,131
14	Administrative services under the IASA	Kern River Gas Transmission Company	107, 923	169,609
15				
16	Gas transportation services	Kern River Gas Transmission Company	501, 547	3,175,157
17				
18	Relocation services	HomeServices of America, Inc.		1,870,846
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Financial support services and employee benefits	Interwest Mining Company	146	508,808
22				
23	Information technology and royalties	Bridger Coal Company	146	493,674
24				
25	Information technology support services	Energy West Mining Company	146	269,154
26				
27				
28	Administrative services under the IASA	MEC	146	1,209,082
29				
30	Administrative services under the IASA	MidAmerican Transmission LLC	146	535,508
31				
32	Administrative services under the IASA	Northern Natural Gas Company	146	309,919
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) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/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	Rail services / right-of-way fees	BNSF Railway Company	151,507,567,589	34,192,694
4				
5	Financial transactions related to energy hedging			
6	activity and banking services	Wells Fargo & Company		20,050,677
7				
8	Computer hardware and software and computer			
9	systems consulting and maintenance services	International Business Machines		2,167,361
10				
11	Rating agency fees	Moody's Investors Service	181, 186, 930.2	517,067
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				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				

Schedule Page: 429 Line No.: 3 Column: c

Accounts charged for Bridger Coal Company: 151, 232, 501, 513 and 921.

Schedule Page: 429 Line No.: 3 Column: d

Non-power goods or services provided by Bridger Coal Company are as follows:

Coal purchases	$ 149,696,962
Support services	164,962
	$ 149,861,924

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: c

Accounts charged for Interwest Mining Company: 421, 426.1, 426.5, 557 and 929.

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. Interwest 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

This footnote applies to all occurrences of "Administrative services under the IASA" on page 429. "IASA" is the Intercompany Administrative Services Agreement between MidAmerican Energy Holdings Company ("MEHC") and its subsidiaries. Amounts which are chargeable to or from another affiliate are assigned first by coding to the specific affiliate. These charges are based on actual labor, benefits and operational costs incurred. Amounts not directly assignable to an individual affiliate, such as work performed where multiple affiliates benefit, are assigned on the basis of allocations, as described below:

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. Eight combinations of this allocator are used for allocating services that benefit different companies within the MEHC organization.

Legislative and Regulatory: The Legislative and Regulatory allocation is used to allocate costs incurred by MEHC'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 MEHC 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.

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.

Processes: This allocator distributes costs of electronic data interchange software and services based on the process count within each affiliate using such software or services.

Plant: This allocator distributes costs of managing the corporate insurance function based on assets for each affiliate.

Schedule Page: 429 Line No.: 11 Column: c

Accounts charged for MEHC: 426.4, 426.5, 923 and 928.

Schedule Page: 429 Line No.: 11 Column: d

Excluded from this line are “convenience” payments made to vendors by one entity on behalf of, and charged to, other entities within the MEHC group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power.

Included in this line are amounts charged to PacifiCorp for awards granted to PacifiCorp employees under the long-term incentive plan (“LTIP”) maintained by MEHC. Excluded from this page are reimbursements by MEHC for payments made by PacifiCorp to its employees under the LTIP upon vesting of the awards. Also excluded from this page are reimbursements of deferred compensation and annual incentive payments associated with transferred employees.

The convenience payments, the LTIP reimbursements and the deferred compensation and 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, 426.4, 426.5, 923 and 928.

Schedule Page: 429 Line No.: 12 Column: d

Excluded from this line are “convenience” payments made to vendors by one entity on behalf of, and charged to, other entities within the MEHC group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute “services” as required by this page.

Schedule Page: 429 Line No.: 18 Column: c

Accounts charged for HomeServices of America, Inc.: 501, 506, 535, 548, 549, 556, 557, 560, 561.2, 568, 580, 581, 590, 593, 595, 597, 902, 903, 908, 921 and clearing accounts.

Schedule Page: 429 Line No.: 21 Column: d

PacifiCorp provides Interwest Mining Company with financial and administrative support and technical services as well as employee benefits for Interwest Mining Company's employees. 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.: 23 Column: d

Non-power goods or services provided to Bridger Coal Company are as follows:

Information technology	$ 465,184
Royalties	28,490
	$ 493,674

Schedule Page: 429 Line No.: 30 Column: d

Excluded from this line are “convenience” payments made to vendors by one entity on behalf of, and charged to, other entities within the MEHC group. Such affiliate charges reflect the ability to obtain price discounts as a result of larger purchasing power and do not constitute “services” as required by this page.

Schedule Page: 429.1 Line No.: 3 Column: d

Non-power goods or services provided by BNSF Railway Company are as follows:

Rail services	$ 34,155,587
Right-of-way fees	37,107
	$ 34,192,694

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.: 6 Column: c

Accounts charged for Wells Fargo & Company: 181, 186, 228.3, 419, 427, 501, 547, 560, 588, 903 and 921.

Schedule Page: 429.1 Line No.: 9 Column: c

Accounts charged for International Business Machines: 165, 232, 903, 909, 921 and 935.

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Schedule	Page No.